BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

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| Federal Power Act Section 202(c) | ) |
| Emergency Order: Tri-State | ) |
| Generation and Transmission | ) |
| Association, Platte River Power | ) |
| Authority, Salt River Project, | ) |
| PacifiCorp, and Xcel Energy | ) |

Exhibit to
Motion to Intervene and Request for Rehearing and Stay of
Public Interest Organizations

Exhibit 2-40:
PIOs' RFR of July Resource Adequacy Report

BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

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| *In re* | ) |
| Resource Adequacy Report | ) |
| Evaluating the Reliability and Security | ) |
| Of the United States Electric Grid | ) |
| | ) |

Motion to Intervene and Request for Rehearing of
Natural Resources Defense Council, the Ecology Center, Environmental Defense Fund, Environmental Law and Policy Center, Public Citizen, Sierra Club, and Vote Solar

## I. INTRODUCTION

Pursuant to section 313 of the Federal Power Act ("the Act"), 16 U.S.C. § 825*l*, Natural Resources Defense Council, the Ecology Center, Environmental Defense Fund, Environmental Law and Policy Center, Public Citizen, Sierra Club, and Vote Solar ("Public Interest Organizations") hereby move, to the extent necessary, to intervene and request rehearing of the Department of Energy's ("Department" or "DOE") "Resource Adequacy Report: Evaluating the Reliability and Security of the United States" ("RAR").[1] The Department issued the RAR in response to Executive Order 14,262 *Strengthening the Reliability and Security of the United States Electric Grid,* April 8, 2025 ("Grid EO"),[2] and claims that the RAR is a "uniform methodology to identify at-risk region(s) and guide reliability interventions" as directed by the Grid EO.[3] But the Department simultaneously disclaims the utility of the RAR to guide interventions uniformly, acknowledging on the very first page that the various "entities responsible for the maintenance and operation of the grid" have information "that could further enhance the robustness of reliability decisions" in their parts of the grid.[4]

The flaws in the RAR continue. The Department overstates assumptions about demand growth and likely retirements while understating likely new entry, building into the RAR an inherent bias toward a finding of inadequate resource adequacy. The Department also departs from best practices by using a

[1] July 7, 2025, https://www.energy.gov/sites/default/files/2025-07/DOE%20Final%20EO%20Report%20%28FINAL%20JULY%207%29.pdf (attached as Ex. 1) (hereinafter, the "RAR").

[2] 90 Fed. Reg. 15521 (Apr. 8, 2025) (hereinafter "Grid EO").

[3] *Id.* at vi.

[4] *Id.* at i.

deterministic approach, which fails to account for necessary uncertainties and demonstrates that the RAR's findings should not be taken as conclusive or form the basis for further extraordinary actions. And on some critical aspects of the RAR analysis, the Department simply fails to explain its own methodology; while the Department describes two thresholds at which the RAR projects outages will occur, it fails to explain when it applies the standard threshold and when it applies the elevated one. These flaws render any reliance on the RAR to "guide reliability interventions" arbitrary and capricious.

While the Department acknowledges that the RAR is unsuitable to guide reliability interventions uniformly and provided no notice or opportunity to comment, the Department nevertheless does not clarify how it will use the RAR, creating confusion as to whether the RAR, in conjunction with the Grid EO, is intended to function as a final rule. Public Interest Organizations believe that the RAR should not be used as the basis for future action by the Department. We submit this request for rehearing in an abundance of caution, to the extent the Department later argues that any of these issues must have been raised in a request for rehearing within 30 days of the publication of the RAR, 16 U.S.C. § 825*l*. We also reserve our right to argue in later proceedings that 16 U.S.C. § 825*l* does not apply.

In sum, the RAR is a poorly crafted solution in search of a problem; there is no "energy emergency" and the regulatory bodies who actually possess authority to ensure resource adequacy are doing their jobs. Consequently, the RAR serves no useful purpose and should simply be withdrawn. By DOE's own admission, the RAR cannot reasonably be relied on to guide DOE interventions, nor, given the false premise and multiple mistaken assumptions, does it provide any value even as a purely informational report. On the contrary, it will only cause confusion for grid operators, energy providers, and members of the public. In the alternative, the Department should not use the RAR as support for any reliability intervention or other action until and unless it (1) provides notice of the statutory authority under which DOE issued the RAR and publishes all data underlying the RAR, (2) explains in detail the specific uses for the methodology, and (3) allows interested parties to comment on the RAR before finalizing it.

## II. STATEMENT OF ISSUES

1. The Department intrudes on Federal Energy Regulatory Commission ("FERC" or "the Commission") and state authority. 16 U.S.C. §§ 824a(c),824o-1; 42 U.S.C. § 7113.
2. The RAR's findings, even if accurate, do not demonstrate any emergency allowing the Department to compel generation under the Federal Power Act. 16 U.S.C. § 824a(c); S. Rep. No. 74-621 (1935); 10 C.F.R. § 205.371; 10 C.F.R. § 205.375; 46 Fed. Reg. 39,985.

3. The RAR is analytically flawed and does not rely upon substantial evidence. 16 U.S.C. 824a(a); 16 U.S.C. § 824o(a)(3).
4. The Department cannot use the RAR as a "uniform methodology" without giving notice and taking public comment. 5 U.S.C. §§ 552, 553; 10 C.F.R. §§ 205.371; 205.373.
5. The Department cannot use the RAR as a "uniform methodology" without following National Environmental Policy Act procedural requirements. 42 U.S.C. § 4332(C).

## III. INTERVENTION

Each of the Public Interest Organizations has interests that may be directly and substantially affected by the use of this RAR as a "uniform methodology" to guide "reliability interventions," including the issuance of Emergency Orders under Section 202(c) of the Federal Power Act, 16 U.S.C. § 824a(c).[5] To the extent that the RAR is determined to be an Order or Rule, each party may intervene in this proceeding.[6] And to the extent the Department treats the RAR as binding and uses it to guide reliability interventions, each of the Public Interest Organizations and their members will suffer concrete injuries that are redressable through rehearing.[7] Each organization is therefore aggrieved if the RAR is a "uniform methodology" for use in guiding interventions, as the Department purports, and each organization may properly apply for rehearing, assuming without conceding that the rehearing procedures apply.[8]

### A. Natural Resources Defense Council

Natural Resources Defense Council ("NRDC") is a national non-profit membership organization whose mission includes ensuring the rights of all people to clean air, clean water, and healthy communities. NRDC has a longstanding organizational commitment to protect the interests of its members and to reducing pollution caused by fossil fuel fired power plants. NRDC works to achieve clean

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[5] *See* RAR, Ex. 1 at iv.

[6] *See* U.S. Dep't of Energy, DOE 202(c) Order Rehearing Procedures, https://www.energy.gov/ceser/doe-202c-order-rehearing-procedures (last visited June 18, 2025) (archived version attached as Ex. 2) (hereinafter "DOE Rehearing Procedures"). This website was altered after June 18, 2025, and the procedures were removed. *Compare* https://web.archive.org/web/20250604093213/https://www.energy.gov/ceser/doe-202c-order-rehearing-procedures with the current website. *See also* Email from Lot Cooke, U.S. Dep't of Energy to Linda Alle-Murphy Re: Rehearing procedures for DOE Order No. 202-05-3 (December 30, 2005) (recommending that "a party seeking rehearing can look for procedural guidance to [Federal Energy Regulatory Commission's ("FERC")] Rules of Practice and Procedure, 18 CFR Part 385.") (attached as Ex. 3).

[7] *See, e.g. Alcoa Inc. v. FERC*, 564 F.3d 1342, 1346 (D.C. Cir. 2009).

[8] *See* 16 U.S.C. § 825*l*(a); *Wabash Valley Power Ass'n, Inc. v. FERC*, 268 F.3d 1105, 1112-13 (D.C. Cir. 2001); *NextEra Energy Res. v. ISO New Eng., Inc.*, 157 FERC ¶ 61,059, at P 5 (2016).

energy solutions that will lower consumer energy bills, meet greenhouse gas emission reduction goals, accelerate the use of energy efficiency and renewable energy, and ensure that clean energy is affordable and accessible to all. NRDC has hundreds of thousands of members across the United States. These NRDC members are harmed by orders to operate fossil fuel powered generation past planned retirement dates because continued operation will subject NRDC members to air and water pollution in the areas where they live, work, and recreate. NRDC members are also exposed to the noise and visual impacts of these facilities' operations. In addition, NRDC members are ratepayers in regions who will be subject to higher electric bills as a result of new or renewed 202(c) Orders issued as a result of the RAR. For that reason, NRDC filed requests for rehearing of DOE's 202(c) orders issued to the J.H. Campbell and Eddystone plants, the latter of which explicitly stated that it would be reexamined following publication of the methodology. NRDC has five U.S. offices that also will be subject to higher electric bills as a result of "reliability interventions" undertaken as a result of the RAR's "uniform methodology." Moreover, NRDC has a sustainable operations plan with a goal of reducing net creation of greenhouse gas emissions derived from building operational activity to zero. NRDC and its members therefore have a strong interest in promoting actions that displace less cost-effective fossil generation with more cost-effective clean energy.

### B. The Ecology Center

The Ecology Center is a Michigan-based non-profit organization headquartered in Ann Arbor, Michigan, with additional offices in Detroit, Michigan. Ecology Center is a public interest organization with more than 50 years of experience advocating for clean energy production, healthy communities, environmental justice, and a sustainable future. Ecology Center works at the local, state, and federal level. Its programs address systemic sources of poor health and environmental degradation through unique partnerships with environmental health and environmental advocates. Ecology Center has over 6,000 members and supporters, that live, use electricity, and pay electric bills in Michigan and could be subject to higher electric bills as a result of new or renewed 202(c) Orders issued as a result of the RAR. In addition, Ecology Center members are harmed by orders to operate fossil fuel powered generation past planned retirement dates because continued operation will subject Ecology Center members to air and water pollution in the areas where they live, work, and recreate.

### C. Environmental Defense Fund

The Environmental Defense Fund ("EDF") is a non-profit membership organization with hundreds of thousands of members nationwide whose mission is to build a vital Earth for everyone by preserving the natural systems on which all life depends. Guided by expertise in science, economics, law, and business partnerships, EDF seeks practical and lasting solutions to address environmental problems and protect human health, including in particular by addressing pollution from the power sector. On behalf of its members, EDF works with partners across

the private and public sectors to engage in utility regulatory forums at the federal level and throughout the United States to advocate for policies that will create an affordable, reliable, and low pollution energy system. Recent 202(c) Orders issued by the DOE have harmed members of EDF by causing increases in pollution, which impact the health of people and nature, and in energy costs. EDF has submitted requests for rehearing regarding the DOE Orders related to the J.H. Campbell and Eddystone power plants and a Petition for Review regarding the DOE Order regarding the J.H. Campbell plant. Further 202(c) Orders issued as a result of the RAR, including extensions of the J.H. Campbell and Eddystone orders and orders directed at other generators, will result in further pollution and cost impacts that will harm EDF members.

### D. Environmental Law and Policy Center

Environmental Law and Policy Center ("ELPC") is a not-for-profit environmental organization with members, contributors, and offices throughout the Midwest. Among other things, ELPC advocates before state public service commissions and the Federal Energy Regulatory Commission for clean, reliable energy generation in order to reduce ratepayer costs and improve environmental outcomes. ELPC members in the Midwest live, work, and recreate near power plants that burn coal or other fossil fuels and are directly impacted by their pollutants. In addition, ELPC members are ratepayers in regions who could be subject to higher electric bills as a result of new or renewed 202(c) Orders issued as a result of the RAR. ELPC and its members could be subject to higher electric bills and impacted by additional pollution as a result of "reliability interventions" undertaken as a result of the RAR's "uniform methodology." ELPC has a longstanding organizational commitment to protect the interests of its members, to reduce pollution caused by fossil fuel-fired power plants, and to promote clean, reliable energy generation.

### E. Public Citizen

Public Citizen, Inc. hereby intervenes in these proceedings. Public Citizen, Inc. is an active intervenor and participant before the Federal Energy Regulatory Commission in Federal Power Act proceedings, as well as before the U.S. Department of Energy in both electricity export and natural gas export dockets to ensure just and reasonable rates and that utilities' operations are consistent with the public interest. Established in 1971, Public Citizen, Inc. is a national, not-for-profit, non-partisan, research and advocacy organization representing the interests of American household consumers. Public Citizen has members in all 50 states and represents the interests of consumers, not represented by any other party in this proceeding. Financial details about our organization are on our website: www.citizen.org/about/annual-report/.

### F. Sierra Club

Sierra Club is a national environmental non-profit whose purpose is to explore, enjoy, and protect the wild places of the earth; to practice and promote the responsible use of the earth's ecosystems and resources; to educate and enlist humanity to protect and restore the quality of the natural and human environment; and to use all lawful means to carry out these objectives. To those ends, the Sierra Club and its members have worked to limit pollution caused by fossil-fuel-fired power plants through public education and advocacy at the local, state, and federal level. Sierra Club represents over 640,000 members nationwide, many of whom reside and recreate in the regions in which the RAR purports to identify resource shortfalls requiring the continued operation of coal- and gas-fired generation. Sierra Club members in those areas would be harmed by the pollution and the increased utility rates caused by any such continued operation.

### G. Vote Solar

Vote Solar is an independent 501(c)(3) non-profit working to re-power the U.S. with clean energy by making solar power more accessible and affordable through effective policy advocacy. In over half of the country, Vote Solar seeks to promote the development of solar at every scale, from distributed rooftop solar to large utility-scale plants. Vote Solar has over 90,000 members nationally. Vote Solar members are ratepayers in regions who could be subject to higher electric bills as a result of new or renewed 202(c) Orders issued as a result of the RAR. Vote Solar is not a trade organization, nor does it have corporate members. Vote Solar is committed to promoting clean, renewable energy and transitioning away from coal generation.

## IV. BACKGROUND

### A. Executive Orders

The genesis of the RAR lies in the President's unsupported day one declaration of a national energy emergency: *Declaring a National Energy Emergency* ("Energy Emergency EO").[9] That declaration's lack of factual underpinning was highlighted in a recent report by DOE's independent statistics and analysis arm, the Energy Information Administration ("EIA"). The EIA report highlights how U.S. energy production and exports are currently at an all-time high.[10] Nonetheless, the Energy Emergency EO was cited as a basis for the

[9] Exec. Order No. 14,156, 90 Fed. Reg. 8433 (January 20, 2025) (hereinafter "Energy Emergency EO") (attached as Ex. 4). *See* also RAR, Ex. 1 at vi (explaining that the Grid EO "builds on" the Energy Emergency EO).

[10] *See* U.S. EIA, *U.S. primary energy production, consumption, and exports increased in 2024* (June 20, 2025), https://www.eia.gov/todayinenergy/detail.php?id=65524.

President's follow-up grid-specific executive order, the Grid EO, that led to DOE's publication of the RAR.[11]

The Grid EO directed DOE to take three steps to address the President's assertion that there may be lack of grid reliability in the future, including: 1) to streamline the processes to issue orders pursuant to Federal Power Act Section 202(c);[12] 2) to develop a reserve margin assessment methodology and use it to identify at risk regions and critical energy resources within those regions and to publish that methodology within 90-days of the Grid EO;[13] and 3) to establish a protocol for identifying critical generating resources and taking action to prevent retirement or conversion of the fuel source of such resources.[14]

Notably, the Grid EO was issued in conjunction with a series of actions by President Trump and DOE designed explicitly to prop up the coal and gas industries, including: 1) Executive Order 14,261, *Reinvigorating America's Beautiful Clean Coal Industry,*[15] which seeks to restart coal leasing and expand coal mining on federal lands, in addition to making these processes easier by offering loans and streamlining permitting;[16] 2) a Presidential Proclamation entitled *Regulatory Relief for Certain Stationary Sources to Promote American Energy* that exempts coal plants from complying with the U.S. Environmental Protection Agency's updated Mercury and Air Toxics Standards;[17] and 3) Executive Order 14,260, *Protecting American Energy from State Overreach*,[18] which directs the U.S.

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[11] Nor does the Energy Emergency EO supply legal support for the Grid EO. Under the National Emergencies Act, 50 U.S.C. § 1631, a declaration of national emergency does not authorize the exercise of emergency powers "unless and until the President specifies the provisions of law under which he proposes that he, or other officers will act." But as Congress made clear, the statute "is not intended to enlarge or add to Executive power" such as authority under Section 202(c), only to "establish clear procedures and safeguards for the exercise by the President of emergency powers conferred on him by other statutes." S. Rep. No. 94-1168, 3 (1976).

[12] Grid EO Section 3(a).

[13] *Id.* Section 3(b).

[14] *Id.* Section 3(c).

[15] *See* Exec. Order No. 14,261, 90 Fed. Reg. 15,517 (Apr. 8, 2025).

[16] DOE simultaneously announced several initiatives to subsidize the coal industry, including loan guarantees for coal-fired power plant projects. Dep't of Energy, *Energy Department Acts to Unleash American Coal by Strengthening Coal Technology and Securing Critical Supply Chains* (Apr. 8, 2025), https://www.energy.gov/articles/energy-department-acts-unleash-american-coal-strengthening-coal-technology-and-securing.

[17] Proclamation No. 10914, 90 Fed. Reg. 16777 (Apr. 8, 2025).

[18] Exec. Order No. 14,260, 90 Fed. Reg. 15513 (Apr. 8, 2025).

Department of Justice to take action to block states' exercises of their police powers to protect their residents from pollution caused by coal and fossil-fuel sources.[19]

## B. RAR

On July 7, 2025, DOE published the RAR on its website. The RAR includes a deterministic analysis of the resource adequacy of the current electric system and three 2030 cases: (1) the Plant Closure case includes 104 GW of coal and gas retirements plus 100% of NERC's Tier 1 additions; (2) the No Plant Closures case includes no retirements but 100% of NERC's Tier 1 additions; and (3) the Required Build case begins with the Plant Closures scenario and projects what additional added perfect capacity would be needed to meet the RAR's determined reliability standards.[20] Each of the three 2030 scenarios assume 50 GW of load growth from data centers and an additional 51 GW of load growth from other sources.[21] The Department finds in the RAR that, under the current system, only ERCOT fails to achieve DOE's selected resource adequacy targets,[22] but that, based on the methodology used to forecast the 2030 scenarios, there will be broader resource adequacy issues in 2030.[23] And, notwithstanding the RAR's upfront acknowledgement that the analysis used "could benefit greatly from the in-depth engineering assessments which occur at the regional and utility level,"[24] the Department proceeds to make broad declarations of future need based on its findings in the RAR.[25]

DOE explained that the RAR was being issued pursuant to the Grid EO. The RAR incorporates a full copy of the Grid EO and explains that "[t]his report serves as DOE's response to [the Grid EO's] Section 3(b) … by delivering the required uniform methodology to identify at-risk region(s) and guide reliability

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[19] These actions mimic President Trump's failed efforts to prop up the coal industry during his first term, including DOE's proposed rule, soundly rejected by FERC, that would have provided assured cost recovery (including a return on equity) for coal and nuclear plants (*see* 162 FERC ¶ 61,012), and the President's unfulfilled directive that DOE use Section 202(c) and the Defense Production Act to block closure of uneconomic coal plants while requiring grid operators to bear the costs. *See* Draft Memorandum (May 29, 2018), https://embed.documentcloud.org/documents/4491203-Grid-Memo/.

[20] RAR, Ex. 1 at 4-5.

[21] *Id.* at 2-3, 15-17.

[22] *Id.* at 7.

[23] *Id.* at 6-9.

[24] *Id.* at i.

[25] *Id.* at 1-2. *See also*, DOE Fact Sheet, https://www.energy.gov/sites/default/files/2025-07/DOE_Fact_Sheet_Grid_Report_July_2025.pdf; DOE Press Release, https://www.energy.gov/articles/department-energy-releases-report-evaluating-us-grid-reliability-and-security.

interventions."[26] DOE's statement that it intends to use the methodology "to guide reliability interventions" and that DOE will continue to use the RAR "on a regular basis to ensure its usefulness for effective action among industry and government decision-makers across the United States" suggests that the RAR may be intended to also serve as the protocol called for by Section 3(c) of the Grid EO.[27] But the RAR fails to clarify this, or, if the RAR does not also serve as DOE's response to Section 3(c), whether a protocol has been or will be developed, or whether any protocol will be made public. The RAR does not include any discussion of Section 3(a) of the Grid EO. To the extent that the Department addressed that portion of the Grid EO's directions, it has not made any process changes public. On the contrary, the Department has made its processes under Section 202(c) even less transparent by removing the existing process guidance from the DOE website.[28]

Notwithstanding the statement in the RAR that DOE intends to use the "methodology to identify at-risk region(s) and guide reliability interventions," e.g., Section 202(c) Orders,[29] other portions of the RAR make clear that it can't and shouldn't be used as a basis for interventions, specifically not issuance of 202(c) Orders. First and foremost, the reliability projections in the RAR focus on conditions five years from now and concede that there are not current grid conditions that fit within Section 202(c)'s definition of an "emergency." Second, the Department candidly concedes the RAR's lack of robustness: "DOE acknowledges that the resource adequacy analysis that was performed in support of this study could benefit greatly from the in-depth engineering assessments which occur at the regional and utility level. The DOE study team built the methodology and analysis upon the best data that was available. However, entities responsible for the maintenance and operation of the grid have access to a range of data and insights that could further enhance the robustness of reliability decisions, including resource adequacy, operational reliability, and resilience."[30]

### C. Section 202(c) Orders

Section 202(c) of the Federal Power Act allows the Secretary of Energy, in certain emergency situations, to require by order temporary connections of facilities, and generation, delivery, interchange, or transmission of electricity as the Secretary

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[26] RAR, Ex. 1 at vi.

[27] *Id.*

[28] *Compare* https://web.archive.org/web/20250604093213/https://www.energy.gov/ceser/doe-202c-order-rehearing-procedures with the current website.

[29] *See* Dep't of Energy, *Department of Energy Releases Report on Evaluating U.S. Grid Reliability and Security* (July 7, 2025), https://www.energy.gov/articles/department-energy-releases-report-evaluating-us-grid-reliability-and-security ("The methodology also informs the potential use of DOE's emergency authority under Section 202(c) of the Federal Power Act.").

[30] RAR, Ex. 1 at i.

determines will best meet the emergency and serve the public interest. Section 202(c) has an important purpose: to mitigate electricity shortages caused by war, drought, and other emergencies. In granting DOE the authority that Section 202(c) provides, Congress considered the severe societal consequences of blackouts and determined that avoiding those consequences justified allowing DOE to act without notice and to require operations that override environmental laws. But Congress was also very careful to narrowly limit DOE's use of that authority, as the title of the provision makes clear, to "temporary" "emergency" situations.[31] And while the statute doesn't define "emergency," DOE's regulations include a lengthy definition which reinforces the key element in the statute: 202(c) orders are for situations that are sudden and unexpected, not for longer term grid management.[32]

1. DOE's Past Use of 202(c) Orders

The Department's application of Section 202(c) consistently confirms the urgency of the conditions necessary to invoke the provision and underscores the lack of authority for the planned implementation scheme described in the Grid EO and RAR.[33] The Department's predominant practice has been to use Section 202(c) to address specific, imminent, and unexpected shortages—not to address longer-term reliability concerns or demand forecasts.[34]

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[31] *See, e.g., Richmond Power & Light,* 574 F.2d at 617 (Section 202(c) "speaks of 'temporary' emergencies, epitomized by wartime disturbances, and is aimed at situations in which demand for electricity exceeds supply and not at those in which supply is adequate but a means of fueling its production is in disfavor.").

[32] 10 C.F.R. § 205.371: "'Emergency,' as used herein, is defined as an unexpected inadequate supply of electric energy which may result from the unexpected outage or breakdown of facilities for the generation, transmission or distribution of electric power. Such events may be the result of weather conditions, acts of God, or unforeseen occurrences not reasonably within the power of the affected 'entity' to prevent. An emergency also can result from a sudden increase in customer demand, an inability to obtain adequate amounts of the necessary fuels to generate electricity, or a regulatory action which prohibits the use of certain electric power supply facilities. Actions under this authority are envisioned as meeting a specific inadequate power supply situation. Extended periods of insufficient power supply as a result of inadequate planning or the failure to construct necessary facilities can result in an emergency as contemplated in these regulations. In such cases, the impacted 'entity' will be expected to make firm arrangements to resolve the problem until new facilities become available, so that a continuing emergency order is not needed. Situations where a shortage of electric energy is projected due solely to the failure of parties to agree to terms, conditions or other economic factors relating to service, generally will not be considered as emergencies unless the inability to supply electric service is imminent. Where an electricity outage or service inadequacy qualifies for a section202(c) order, contractual difficulties alone will not be sufficient to preclude the issuance of an emergency order."

[33] *See FTC v. Bunte Brothers, Inc.*, 312 U.S. 349, 352 (1941) ("[J]ust as established practice may shed light on the extent of power conveyed by general statutory language, so the want of assertion of power by those who presumably would be alert to exercise it, is equally significant in determining whether such power was actually conferred.").

[34] *See, e.g.,* Dep't of Energy Order No. 202-22-4 (Dec. 24, 2022) (responding to ongoing severe winter storm producing immediate and "unusually high peak load" between December 23 and

The law also requires the Department to narrowly tailor the remedies in Section 202(c) orders to ensure that the orders only address the stated emergency, limit the order to "only [the] hours necessary to meet the emergency," be "consistent with any applicable Federal, State, or local environmental law or regulation," and to "minimize[] any adverse environmental impacts.[35] Up until recently, the Department has routinely followed these provisions of the law.[36]

2. DOE's Recent Misuse of Section 202(c)

Prior to issuance of the RAR but consistent with the direction in the Grid EO, DOE issued two Section 202(c) orders blocking the planned closures of two fossil-fuel fired generation resources that were unreliable, uneconomic, and at the end of their useful lives: the J.H. Campbell coal-fired plant in West Olive Michigan,[37] and units 3 and 4 of the Eddystone oil and gas fired plant in Eddystone, Pennsylvania.[38] The Eddystone 202(c) Order stated that "DOE plans to use this methodology [i.e., the RAR] to further evaluate Eddystone Units 3 and 4," thus raising questions about DOE's intentions as to the legal status and efficacy of the RAR.

Public Interest Organizations filed requests for rehearing for both the J.H. Campbell and Eddystone 202(c) Orders.[39] In both cases DOE failed to identify conditions that would qualify as "emergencies" for the purpose of issuance of Section 202(c) Orders. And both Section 202(c) Orders impose significant costs on ratepayers,[40] while increasing emissions of air pollutants and providing no

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December 26) (attached as Ex.5); Department of Energy Order 202-20-2 (Sept. 6, 2020) at 10-2 (responding to shortages produced by ongoing extreme heat and wildfires) (attached as Ex.6); *see also* Benjamin Rolsma, *The New Reliability Override*, 57 CONN. L. REV. 789, 803-4 (describing "sparing[]" use of Section 202(c) outside of wartime shortages during the twentieth century) (attached as Ex. 7).

[35] 16 U.S.C.§ 824a(c)(2).

[36] *See, e.g.,* Ex.5, Dep't of Energy Order No. 202-22-4 (Dec. 24, 2022) at 4-7 (limiting order to the 3 days of peak load, directing PJM to exhaust all available resources beforehand, requiring detailed environmental reporting, notice to affected communities, and calculation of net revenue associated with actions violating environmental laws); Ex.6, Dep't of Energy Order 202-20-2 (Sept. 6, 2020) at 3-4 (limiting order to the 7 days of peak load, directing CAISO to exhaust all available resources beforehand, requiring detailed environmental reporting).

[37]Dep't of Energy Order No. 202-25-3 (May 23, 2025) (attached as Ex. 8).

[38]Dep't of Energy Order No. 202-25-4 (May 30, 2025) (hereinafter "Eddystone 202(c) Order") (attached as Ex. 9).

[39] Mot. to Intervene and Request for Rh'g and Stay of Pub. Int. Orgs., DOE Ord. No. 202-25-3 (June 18, 2025) (hereinafter "Campbell RFR") (attached as Ex.10);Mot. to Intervene and Request for Rh'g and Stay of Pub. Int. Orgs., DOE Ord. No. 202-25-4 (June 27, 2025) (hereinafter "Eddystone RFR") (attached as Ex.11).

meaningful corresponding reliability benefit.[41] The Department denied both of Public Interest Organization's requests for rehearing by operation of law.[42]

### D. Existing Mechanisms Ensure Resource Adequacy

In the United States, how electricity is bought and sold varies by region. Electric utilities can be either traditionally regulated and operate as vertically integrated monopolies, or they can operate in deregulated, competitive markets where electric energy prices are set by the market. Both vertically integrated utilities and utilities in deregulated markets are subject to federal oversight, and in some of the deregulated states, the state nonetheless exercises oversight over the terms of retail supply offers, especially for retail customers. And all utilities are subject to reliability standards developed by the North American Electric Reliability Corporation ("NERC") and approved by FERC. In sum, FERC, Regional Transmission Organizations ("RTOs"), States, and NERC all play a hand in ensuring resource adequacy.

1. Vertically integrated utilities

Until the 1990s, utilities were generally vertically integrated such that generation, transmission, and distribution resources were all held by the same entity.[43] Vertically integrated utilities must seek state approval for power plant investments.[44] Many state regulators require utilities to demonstrate the necessity of proposed investments through an integrated resource planning process.[45] This process is used for long-term planning and requires the utility to justify its investments and demonstrate how it plans to meet customer electricity demand.[46] Even though vertically integrated utilities generate their own electricity, many

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[40] *See e.g.* U.S. Sec. and Exch. Comm'n, Form 10-Q, Consumers Energy Company Quarterly Report For the Quarterly Period Ended June 30, 2025, at 39, 62, 92 (2025) https://d18rn0p25nwr6d.cloudfront.net/CIK-0000201533/10a900b7-263b-4ccd-82a0-4162ba7ae5f2.pdf (describing costs of $29 million to operate Campbell through June 30, 2025); FERC Docket No. ER25-2653-000 (PJM proposed cost allocation to implement DOE Order 202-25-4).

[41] *See* Campbell RFR, Ex. 10 at 11-14; Eddystone RFR, Ex. 11 at 56-60. 87-88.

[42] Dep't of Energy, Notice of Denial of Reh'g by Operation of Law and Providing for Further Consideration of Ord. No. 202-25-3A (July 28, 2025) (attached as Ex. 12); Dep't of Energy, Notice of Denial of Reh'g by Operation of Law and Providing for Further Consideration of Ord. No. 202-25-4A (Aug. 1, 2025) (attached as Ex. 13).

[43] *See* Kathryne Cleary and Karen Palmer, *US Electricity Markets 101* (March 17, 2022), Resources for the Future, https://www.rff.org/publications/explainers/us-electricity-markets-101/.

[44] *Id.*

[45] *Id.*

[46] *Id.*

trade with other utilities during times of need. These wholesale market transactions are subject to regulation by FERC.[47]

2. Competitive markets

Advances in technology and statutory changes led to the development of energy markets and merchant generation that is not owned by incumbent utilities.[48] In the 1990s, FERC fostered competitive markets through rules that allowed the establishment of independently-operated voluntary RTOs that determine the prices for energy, capacity, and ancillary services based on procurement and dispatch of least-cost resources through Order Nos. 888, 890, and 2000.[49] As RTO markets expanded, many states deregulated their utility monopolies and required them to join RTOs. Deregulated states use markets to determine which power plants are necessary for electricity generation.[50] Even in deregulated states, the state sites new generation. Market price signals encourage new investment when supply is tight and encourage the retirement of facilities that are no longer competitive when capacity is plentiful. RTOs now account for approximately 2/3 of all electricity sales in the U.S. and have saved consumers billions of dollars, increased reliability, and reduced environmental harm.[51]

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[47] *See* FERC, *Electric Power Markets* (last updated March 27, 2025), https://www.ferc.gov/electric-power-markets.

[48] *See, e.g.,* Order Terminating Rulemaking Proceeding, Initiating New Proceeding, And Establishing Additional Procedures, 162 FERC ¶ 61,012, PP 7-11 (2018); Promoting Wholesale Competition Through Open Access Non-Discriminatory Transmission Services by Public Utilities; Recovery of Stranded Costs by Public Utilities and Transmitting Utilities, Order No. 888, FERC Stats. & Regs. ¶ 31,036, at 31,639-31,645 (1996), order on reh'g, Order No. 888-A, FERC Stats. & Regs. ¶ 31,048, order on reh'g, Order No. 888-B, 81 FERC ¶ 61,248 (1997), order on reh'g, Order No. 888-C, 82 FERC ¶ 61,046 (1998), aff'd in relevant part sub nom. Transmission Access Policy Study Group v. FERC, 225 F.3d 667 (D.C. Cir. 2000), aff'd sub nom. *New York v. FERC*, 535 U.S. 1 (2002).

[49] Order No. 888, FERC Stats. & Regs. ¶ 31,036, at 638-41 (1996), Order No. 890, FERC Stats. & Regs. ¶ 31,241, at 124-352 (1997), Order No. 2000, FERC Stats. & Regs. ¶ 31,089, at 99-130 (1999).

[50] State regulators in competitive markets still practice oversight over utilities. For example, some states, such as Michigan, use both the market and integrated resource planning. *See* Michigan Public Service Commission, *Phase III – Integrated Resource Plan* (last visited Aug. 4, 2025), https://www.michigan.gov/mpsc/commission/workgroups/mi-power-grid/phase-iii-integrated-resource-plan-mirpp-filing-requirements-demand-response-study-energy-waste-red. Other state legislatures or commissions have enacted subsidies to keep nuclear plants alive, such as in New York, Illinois, Ohio, and New Jersey. *See* U.S. EIA, Five states have implemented programs to assist nuclear power plants (Oct. 7, 2019), https://www.eia.gov/todayinenergy/detail.php?id=41534.

[51] *See, e.g.*, Judy Chang et al., The Brattle Group, Potential Benefits of a Regional Wholesale Power Market to North Carolina's Electricity Customers, 1, 3-7 (April 2019) https://www.brattle.com/wp-content/uploads/2021/05/16092_nc_wholesale_power_market_whitepaper_april_2019_final.pdf (discussing billions of dollars in estimated cost saving); Jennifer Chen & Devin Hartman, *Why wholesale market benefits are not always apparent in customer bills*, R Street (Nov. 10, 2021), https://www.rstreet.org/commentary/why-wholesale-market-benefits-are-not-always-apparent-in-

As explained by FERC, its "support of competitive wholesale electricity markets has been grounded in the substantial and well-documented economic benefits that these markets provide to consumers."[52] In addition to billions of dollars of consumer savings, FERC found that competitive markets protect consumers by "providing more supply options, encouraging new entry and innovation, spurring deployment of new technologies, promoting demand response and energy efficiency, improving operating performance, exerting downward pressure on costs, and shifting risk away from consumers."[53]

3. FERC and NERC Reliability Regulation

As part of its role in regulating the wholesale electric industry, FERC has implemented Congressional mandates to ensure system reliability, including establishing NERC as the Electric Reliability Organization, which sets industry standards for grid reliability that are approved by FERC;[54] coordination requirements for the natural gas and electricity market scheduling;[55] investigation and improvements required in light of the grid's response to extreme weather events;[56] and reviewing capacity accreditation processes to ensure that capacity markets generate reliable results.[57]

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customer-bills/ (same); Jeff St. John, *A Western US energy market would boost clean energy. Will it happen?*, Canary Media (Jun. 10, 2024), https://www.canarymedia.com/articles/utilities/a-western-us-energy-market-would-boost-clean-energy.-will-it-happen; John Tsoukalis et al., Assessment of Potential Market Reforms for South Carolina's Electricity Sector, at 6, 46, 77-78 (Apr. 27, 2019), https://www.scstatehouse.gov/CommitteeInfo/ElectricityMarketReformMeasuresStudyCommittee/2022-04-27%20-%20SC%20Electricity%20Market%20Reform_Brattle%20Report.pdf (discussing cost savings across regional wholesale markets).

[52] Order Terminating Rulemaking Proceeding, Initiating New Proceeding, and Establishing Additional Procedures, 162 FERC ¶ 61,012, P 11 (2018).

[53] *Id.* (citation omitted).

[54] PJM, NERC and Reliability Fact Sheet (Jan. 5, 2025), https://www.pjm.com/-/media/DotCom/about-pjm/newsroom/fact-sheets/nerc-and-reliability-fact-sheet.pdf. *See also* PJM, PJM Ensures a Reliable Grid (Jan. 29, 2025), https://www.pjm.com/-/media/DotCom/about-pjm/newsroom/fact-sheets/reliability-fact-sheet.pdf.

[55] PJM, PJM Promotes Gas/Electricity Industry Coordination (Jan. 29, 2025), https://www.pjm.com/-/media/DotCom/about-pjm/newsroom/fact-sheets/gas-electric-coordination-fact-sheet.pdf. *See also* Order 787, 145 FERC ¶ 61,134 (2013); Order 809, 151 FERC ¶ 61,049 (2015).

[56] *See e.g.,* Centralized Capacity Markets in Regional Transmission Organizations and Independent System Operators, 149 FERC ¶ 61,145 (2014) (order addressing technical conferences on, among other things, the 2014 Polar Vortex); Order Approving Extreme Cold Weather Reliability Standards EOP-011-3 and EOP-012-1 and Directing Modification of Reliability Standard EOP-012-1, 182 FERC ¶ 61094 (2023); Order Approving Extreme Cold Weather Reliability Standard EOP-012-2 and Directing Modification, 187 FERC ¶ 61,204 (2024). *See also* FERC, NERC and Regional Staff, Inquiry into Bulk-Power System Operations During December 2022 Winter Storm Elliott (Oct. 2023), https://www.ferc.gov/sites/default/files/2023-11/24_Winter-Storm_Elliot_1107_1300.pdf; FERC, NERC and Regional Entity Joint Staff, The February 2021 Cold Weather Outages in Texas and the

## V. ARGUMENT

### A. The Department Is Intruding on FERC and State Authority.

The Department's authority over reliability is strictly circumscribed to respond to imminent emergencies;[58] this authority does not extend to regulating long-term or overarching aspects of the electricity sector. Rather, Congress reserved to the states and FERC the authority to regulate the electric sector generally and to regulate resource adequacy and reliability specifically. Recent actions—starting with the Energy Emergency EO and culminating in the RAR—indicate, however, that DOE is not remaining in its designated lane.[59] The RAR lays bare the Department's agenda to prop up fossil fuel businesses by utilizing emergency authority in a systematic fashion that goes well beyond the scope of DOE's authority under the Federal Power Act and illegally intrudes upon authorities that Congress has explicitly reserved to the states or given to FERC.

The authority to maintain a reliable electric system in the United States has evolved over the years to include parties at the federal, regional, state, and local levels.[60] But the Department of Energy has never been granted primary regulatory authority over either reliability or resource adequacy of the grid. Rather, the Department of Energy Organization Act of 1977 ("Organization Act")[61] and the

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South Central United States (Nov. 2021), https://www.nerc.com/pa/Stand/Project202107ExtremeColdWeatherDL/FERC%20Presentation-Phase%202.pdf; PJM, Winter Storm Elliott Event Analysis and Recommendation Report (2023), https://www.pjm.com/-/media/DotCom/library/reports-notices/special-reports/2023/20230717-winter-storm-elliott-event-analysis-and-recommendation-report.pdf.

[57] *Id.*; *see also* Order Accepting Tariff Revisions Subject to Condition, 186 FERC ¶ 61,080 (2024).

[58] *See* 16 U.S.C. §§ 824a(c),824o-1.

[59] *See* Energy Emergency EO, Ex. 4; Grid EO Sec. 3 (RAR, Ex. 1 at C); RAR Ex. 1; DOE, DOE Fact Sheet, https://www.energy.gov/sites/default/files/2025-07/DOE_Fact_Sheet_Grid_Report_July_2025.pdf; DOE Press Release, https://www.energy.gov/articles/department-energy-releases-report-evaluating-us-grid-reliability-and-security; Eddystone 202(c) Order, Ex. 9; Dep't of Energy Order No. 202-25-3 (May 23, 2025), Ex. 8.

[60] *New York v. FERC*, 535 U.S. 1, 5-8 (2002) ("Prior to 1935, the States possessed broad authority to regulate public utilities"). *See generally* Nat'l Ass'n of Reg. Util. Comm'rs ("NARUC"), *Resource Adequacy for State Utility Regulators: Current Practices and Emerging Reforms* (Nov. 2023) https://pubs.naruc.org/pub/0CC6285D-A813-1819-5337-BC750CD704E3?_gl=1*oyp366*_ga*MTc1NzM0NTE0LjE3NTM5ODk1NDA.*_ga_QLH1N3Q1NF*czE3NTM5ODk1NDAkbzEkZzEkdDE3NTM5ODk1NzUkajI1JGwwJGgw; NARUC, *Resource Adequacy Primer for State Regulators* (July 2021), https://pubs.naruc.org/pub/752088A2-1866-DAAC-99FB-6EB5FEA73042?_gl=1*1mituzu*_ga*MTc1NzM0NTE0LjE3NTM5ODk1NDA.*_ga_QLH1N3Q1NF*czE3NTM5ODk1NDAkbzEkZzAkdDE3NTM5ODk1NDAkajYwJGwwJGgw.

[61] 42 U.S.C. § 7111 *et seq.*

Federal Power Act[62] give to the Department only narrow, emergency authority over the electric system—for example through Federal Power Act Sections 202(c) and 215A.[63] The President's declaration of an energy emergency (even if it were legitimate) and other executive orders cannot expand these statutorily defined authorities.[64] And while the Department may of course analyze policy implications and issue reports on various topics—as it has done since its founding—DOE's statements indicate that the RAR is not simply a policy analysis. The Department states—without limitation—that it will use the RAR "to identify at-risk region(s) and guide reliability interventions."[65] Thus, taking DOE at its word, the RAR is beyond the Department's authority.

Further, to the extent that it is an indication of the Department's broader scheme, in the RAR, the Department ignores the limitations on its authority and the comparative breadth of authority explicitly reserved to the states and FERC over the Department. "States are responsible for resource adequacy in siting of electric facilities, establishing retail electric rates, and overseeing the reliability of the distribution system."[66] State public utility commissions review utility proposals for long-term impacts to the system's reliability. "Most states address resource adequacy by requiring large investor-owned utilities to file long-term planning documents like integrated resource plans that include strategies for reliably meeting future demand."[67]

The structure and language of the Organization Act and Federal Power Act reflect Congress's deliberate choices to preserve this traditional state authority over generating facilities and to circumscribe the Department's emergency authority in light of the states' role. Congress noted in the Organization Act that "[n]othing in this chapter shall affect the authority of any State over matters exclusively within its jurisdiction."[68] And the first sentence of the Federal Power Act declares that

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[62] Subsequent legislation has also amended and updated these authorities. *See e.g.* Fixing America's Surface Transportation Act (FAST Act), Pub. L. No. 114–94, 129 Stat. 1312 (2015); Energy Policy Act of 2005, Pub. L. No. 109-58, 119 Stat. 594 (2005).

[63] 16 U.S.C. §§ 824a(c), 824o-1.

[64] *See Biden v. Nebraska*, 600 U.S. 477, 500-01 (2023); *see also* S. Rep. No. 94-1168, 3 (1976), (the National Emergencies Act "is not intended to enlarge or add to Executive power. Rather, the statute is an effort by Congress to establish clear procedures and safeguards for the exercise by the President of emergency powers *conferred on him by other statutes*.") (emphasis added).

[65] RAR, Ex. 1 at vi.

[66] NARUC, *Resource Adequacy Primer for State Regulators*, at 9 (July 2021) https://pubs.naruc.org/pub/752088A2-1866-DAAC-99FB-6EB5FEA73042?_gl=1*1mituzu*_ga*MTc1NzM0NTE0LjE3NTM5ODk1NDA.*_ga_QLH1N3Q1NF*czE3NTM5ODk1NDAkbzEkZzAkdDE3NTM5ODk1NDAkajYwJGwwJGgw.

[67] Nat'l Renewable Energy Lab'y, *Explained: Fundamentals of Power Grid Reliability and Clean Electricity*, at 4 (Jan. 2024) https://docs.nrel.gov/docs/fy24osti/85880.pdf.

[68] 42 U.S.C. § 7113.

federal regulation extends "only to those matters which are not subject to regulation by the States."[69] Section 201(b)(1) further states that, except as otherwise "specifically" provided, federal jurisdiction does not attach to "facilities used for the generation of electric energy."[70] The courts have held that Section 201(b)(1) reserves to the states authority over electric generating facilities,[71] including the authority to order their closure.[72] Congress also recognized the states' exclusive authority over generating facilities in Section 202(b), which provides that FERC's interconnection authority does not include the power to "compel the enlargement of generating facilities for such purposes."[73] And when Congress added new authority regarding reliability to the Federal Power Act in 2005, it also still explicitly clarified that "[n]othing in this section shall be construed to preempt any authority of any State to take action to ensure the safety, adequacy, and reliability of electric service within that State, as long as such action is not inconsistent with any reliability standard…."[74]

The RAR also intrudes upon authority that Congress explicitly and repeatedly gave exclusively to FERC, not the Department. In 1935, Congress passed the Federal Power Act, creating the Federal Power Commission to engage in "federal regulation of electricity in areas beyond the reach of state power."[75] However, until the 1970s, the federal government played a very limited role in energy policy and generally left to private industry and state and local governments the task of establishing energy policies and planning.[76] In 1977, Congress passed the Organization Act,[77] creating both the Department and FERC. The Organization Act transferred most of the authority for overseeing the electric system in the

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[69] 16 U.S.C. § 824(a).

[70] *Id.* § 824(b)(1).

[71] *See, e.g., Hughes v. Talen Energy Mktg., LLC*, 578 U.S. 150, 154 (2016).

[72] *Conn. Dep't of Pub. Util. Control v. FERC*, 569 F.3d 477, 481 (2009) (under Section 201(b), states retain the right "to require retirement of existing generators" or to "take any other action in their role as regulators of generation facilities."). *See also Devon Power LLC et al.*, 109 FERC ¶ 61,154, P 47 (2004) ("Resource adequacy is a matter that has traditionally rested with the states, and it should continue to rest there. States have traditionally designated the entities that are responsible for procuring adequate capacity to serve loads within their respective jurisdictions.").

[73] 16 U.S.C. § 824a(b).

[74] 16 U.S.C. § 824o.

[75] *New York v. FERC*, 535 U.S. 1, 6 (2002).

[76] DOE, *A Brief History of the Department of Energy,* https://www.energy.gov/lm/brief-history-department-energy. *See also* DOE, *Department of Energy 1977-1994, A Summary History* (Nov. 1994), https://www.energy.gov/sites/prod/files/2017/09/f36/DOE%201977-1994%20A%20Summary%20History_0.pdf.

[77] Public Law 95–91 (1977), 42 U.S.C. § 7101 *et seq.*

Federal Power Act to FERC, not the Department;[78] the Department retained primary authority only over "emergency interconnection."[79]

While FERC is housed within the Department, FERC is an independent agency with distinct authority from the Department that the Department may not modify or supersede.[80] Generally the Department "is authorized to establish, alter, consolidate or discontinue such organizational units or components within the Department as [the Secretary] may deem to be necessary or appropriate."[81] But this authority explicitly does not extend to FERC. The Organization Act explains that the Department may not abolish "organizational units or components established by" the Organization Act, nor may it "transfer [] functions vested by this chapter in any organizational unit or component."[82] Because the Organization Act created[83] and transferred specific authority to FERC,[84] the Department has no authority to alter FERC itself nor to seize FERC's statutorily prescribed authority.

Further, "the decision of the Commission involving any function within its jurisdiction . . . shall be final agency action . . . and *shall not be subject to further review by the Secretary* or any officer or employee of the Department."[85] While the Department can propose rules under FERC's jurisdiction, FERC maintains "exclusive jurisdiction . . . to take final action on any proposal made by the Secretary."[86] And when the Department proposes a rule in the exercise of its own functions that FERC determines significantly affects any function within FERC's jurisdiction, FERC can insist on changes that DOE must adopt if DOE wants to issue the rule.[87]

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[78] 42 U.S.C. § 7172 (transferring functions from Federal Power Commission to FERC); 42 U.S.C. § 7151 (the function of the Federal Power Commission is transferred to the Secretary except as provided to FERC). The Department and FERC share authority over certain parts of the Federal Power Act that primarily address recordkeeping and administration. 42 U.S.C. § 7172(a)(2) ("The Commission may exercise any power under the following sections to the extent the Commission determines such power to be necessary to the exercise of any function within the jurisdiction of the Commission: (A) sections 4, 301, 302, 306 through 309, and 312 through 316 of the Federal Power Act.").

[79] *See* 42 U.S.C. § 7172(a)(1)(B).

[80] *See* 42 U.S.C.A. § 7112 (Congressional declaration of purpose in establishing Department); 42 U.S.C. § 7171 (establishment of FERC).

[81] 42 U.S.C. § 7253.

[82] 42 U.S.C. § 7253.

[83] 42 U.S.C. § 7171 (establishment of FERC).

[84] 42 U.S.C. § 7172(a) (transferring functions from Federal Power Commission to FERC).

[85] 42 U.S.C. § 7172(g) (emphasis added).

[86] 42 U.S.C. § 7173. *See* 162 FERC ¶ 61,012.

[87] 42 U.S.C. § 7174.

In 2005, Congress expanded FERC's authority to specifically encompass reliability by updating the Federal Power Act in the 2005 Energy Policy Act.[88] While "FERC had previously addressed electric grid reliability in an indirect manner, such as allowing the cost recovery of public utility expenditures that address discrete reliability matters,"[89] there had been no mandatory reliability standards adopted by any federal regulator. When providing recommendations on reliability in 1998, the Department had concluded "that the U.S. Congress should explicitly assign oversight of bulk-power reliability to the FERC."[90] The new Section 215 followed the Department's suggestion and "tasked FERC [—not the Department—] with a direct role over an entire new field of activity."[91] Section 215 authorizes FERC to certify an electric reliability organization; FERC designated NERC. It is therefore NERC that develops reliability standards that FERC reviews to ensure consistency with federal law.[92] The broad reliability authority Congress granted to FERC contrasts with the very narrow, emergency authority in Section 215A that Congress granted to the Department.[93] The RAR appears to duplicate FERC and NERC's reliability efforts, impermissibly intruding upon authority Congress chose to give FERC —subject to elaborate procedural and substantive limitations—not the Department.

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[88] Pub. L. No. 109-58, 119 Stat. 594 (2005).

[89] FERC, *Reliability Primer*, at 5 (2020) https://www.ferc.gov/sites/default/files/2020-04/reliability-primer_1.pdf.

[90] DOE, *Maintaining Reliability in a Competitive U.S. Electricity Industry* at vii-viii, xiv (Sept. 29, 1998), https://certs.lbl.gov/sites/all/files/basic-page/maintainting-reliability-in-competitive-electricity-industry-1998_0.pdf ("The Administration has proposed legislation that would provide the federal oversight necessary to make reliability standards mandatory. The NERC has begun to reinvent itself to respond to the changing needs of the industry. In addition, the FERC has undertaken several reliability initiatives. However, much more is needed. The Congress, for example, urgently needs to clarify the FERC's authority over an electric industry self-regulating reliability organization and expand the FERC's jurisdiction for reliability over the bulk-power system.") ("The Task Force is confident that the electricity industry, overseen by the Federal Energy Regulatory Commission (FERC) and a restructured self-regulating reliability organization (such as the planned North American Electric Reliability Organization [NAERO]), can and will maintain today's high levels of reliability."). *See also* S. Rep. No. 106-324, Electric Reliability 2000 Act (proposals from Congress such as this one gave FERC the authority over reliability).

[91] FERC, *Reliability Primer*, at 5 (2020) https://www.ferc.gov/sites/default/files/2020-04/reliability-primer_1.pdf.

[92] FERC, Reliability Explainer (Aug. 16, 2023) https://www.ferc.gov/reliability-explainer#:~:text=Both%20NERC%20and%20FERC%20have,blackouts%20or%20systematic%20compliance%20failures.

[93] The 2015 amendment to Federal Power Act creating Section 215A (16 U.S.C. 824o-1(d)) gives DOE the authority to issue orders to address emergencies related to malicious acts resulting from physical attacks to the grid at limited 15-day increments.

Finally, the Department arbitrarily and capriciously assumes that the existing systems are not working. The states and FERC have—pursuant to their authority—established systems to maintain resource adequacy and reliability including integrated resource planning processes and capacity markets. These existing systems are designed to signal to build more energy generation when energy demand rises.[94] Recently, as the Department notes in the RAR, energy demand has been rising; but the Department fails to acknowledge that the state and FERC systems already are appropriately responding, negating claims of an emergency or the need for the Department to interfere, as discussed *infra* in Section C.[95] For example, PJM's, SPP's, and MISO's new "fast track" processes—adopted to address concerns of resource adequacy—"alone would add roughly twice what the DOE assumed for the entire nation."[96] The RAR is written arbitrarily and capriciously incorporating the implicit assumption that capacity market results are not reliable, and that market-driven generator retirement is cause for alarm.

In sum, Congress has explicitly reserved to the states and FERC primary regulatory authority over resource adequacy and reliability. The Department's only authority to directly regulate reliability of the electric grid is narrow emergency authority such as Federal Power Act Sections 202(c) and 215A. The Department does not have broader authority to interfere with resource adequacy or reliability regulations. To the extent that the RAR is the confirmation of the attempt to usurp that authority from the states and FERC, via a "uniform methodology" in the RAR, it is outside of DOE's statutory authority and contrary to law.

### B. The Department's Findings in the RAR, Even if Accurate, Do Not Demonstrate Any Emergency Allowing the Department to Compel Generation Under the Federal Power Act.

Even if the findings in the RAR were accurate (which they are not, as explained in Section C below), they would not empower the Department to exercise any statutory authority, under "section 202 of the Federal Power Act" or otherwise, to override state- or market-driven changes to the electricity generating facilities supplying the grid.[97] As discussed in Section A above, the Federal Power Act gives the Department tightly circumscribed authority over resource adequacy planning, to address "emergency" conditions through "such temporary connections of facilities and such generation, delivery, interchange, or transmission of electric energy" as

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[94] *See e.g.* DOE, A Primer on Electric Utilities, Deregulation, and Restructuring of U.S. Energy Markets, at 3.8 (May 2002); GridLab, GridLab Analysis: Department of Energy Resource Adequacy Report, at 4 (July 11, 2025) (hereinafter "GridLab Analysis") (attached as Ex. 14).

[95] GridLab Analysis, Ex. 14 at 2-3.

[96] GridLab Analysis, Ex. 14 at 3.

[97] Grid EO at Sec. 3 (RAR, Ex. 1 at C-3).

"will best meet the emergency and serve the public interest."[98] The statutory text, structure, and history, as well as case law interpreting Section 202(c), the Department's regulations, and its historic use of Section 202(c), all establish that its "emergency" authority is confined to sudden, unexpected, imminent, and specific electricity shortfalls. The information in the RAR, at most, expresses the Department's view that bulk-power system reliability will be insufficient in 2030. The Department's conclusions in the RAR—even if assumed to be accurate for the sake of argument—consequently provide no basis for the Department to manipulate the electricity market.

1. The Federal Power Act only permits the Department to intervene when necessary to address an imminent, unexpected, and specific electricity shortfall.

The Federal Power Act's text, context, and structure, as well as caselaw and the Department's longstanding regulations, all establish that it does not permit the Department to "prevent" generating facilities "from leaving the bulk-power system" or "converting" from one fuel-source to another based on the Department's view of long-term reliability needs.[99] The Act provides the Department only authority to intervene in electricity markets when necessary to address imminent, near-term, and exigent electricity supply shortfalls requiring immediate response, through the cabined authority provided by Section 202(c) of the Act.

*a. The Text of Section 202(c) Narrowly Limits the Department's Authority to Emergencies: Imminent, Unexpected, and Certain Shortfalls in Electricity Supply.*

The Act's text empowers the Department to require generation only in an "emergency;"[100] the Act primarily reserves authority over generation to the states, allocating more limited federal regulatory power to different agencies, *see section* A above. The statute itself does not define "emergency." At the time Congress enacted Section 202(c), Webster's New International Dictionary of the English Language (1930) defined "emergency" as a "*sudden* or *unexpected* appearance or occurrence . . . An *unforeseen* occurrence or combination of circumstances which calls for *immediate* action or remedy; *pressing* necessity; exigency."[101] Contemporary dictionaries similarly define "emergency" as demanding imminence: an emergency

[98] 16 U.S.C. 824a(c).

[99] Grid EO at Sec. 3(c)(ii) (RAR, Ex. 1 at C-4).

[100] 16 U.S.C. § 824a(c).

[101] Emphasis added.

is "an *unforeseen* combination of circumstances or the resulting state that calls for *immediate* action."[102]

The remainder of Section 202(c) underscores the exigency inherent in the governing term "emergency." The authority granted by Section 202(c) is, in the first instance, a war-time power.[103] An "emergency" under the statute is limited to circumstances of similar urgency: "a *sudden* increase in the demand for electric energy," for example.[104]

The text's use of the present tense also underscores that focus on imminent and certain shortfalls: it empowers the Department to act only where "an emergency *exists*."[105] That near-term focus along with the statute's strictly "temporary" authority[106] precludes use of Section 202(c) to pursue long-term policy goals, such as "fear of overdependence" on foreign oil supplies,[107] or "energy independence."[108]

Section 202's overall structure further highlights Section 202(c)'s emphasis on imminent, near-term concerns. The preceding subsections 202(a) and (b) together define and limit the tools by which the federal government may pursue "abundant" energy supplies in the normal course.[109] The resulting statutory "machinery for the

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[102] Merriam Webster's Dictionary 407 (11th ed. 2009) (emphasis added); *see* 3 Oxford English Dictionary 119 (1st ed. 1913) (defining emergency similarly as "a state of things *unexpectedly* arising, and urgently demanding *immediate* action" (emphasis added)); *see also* Rolsma, Ex. 7 at 812 n.147 (noting that dictionaries have given the term "emergency" the "same meaning for many years").

[103] 16 U.S.C. § 824a(c) (beginning with "[d]uring the continuance of any war in which the United States is engaged"); *see Jarecki v. G.D. Searle & Co.*, 367 U.S. 303, 307 (1961) (noting that statutory terms should be interpreted in the context of nearby parallel terms "in order to avoid the giving of unintended breadth to the Acts of Congress").

[104] 16 U.S.C. § 824a(c) (emphasis added); *see Richmond Power & Light,* 574 F.2d at 615 (holding that Section 202(c) "speaks of 'temporary' emergencies, epitomized by wartime disturbances"); S. Rep. No. 74-621, at 49 (1935) (explaining that Section 202(c) provides "temporary power designed to avoid a repetition of the conditions during the last war, when a serious power shortage arose").

[105] 16 U.S.C. § 824a(c) (emphasis added).

[106] 16 U.S.C. § 824a(c).

[107] *Richmond Power & Light*, 574 F.2d at 617.

[108] RAR, Ex. 1 at 1. *See Richmond Power & Light*, 574 F.2d at 614 (Section 202(c) "speaks of 'temporary' emergencies, epitomized by wartime disturbances, and is aimed at situations in which demand for electricity exceeds supply and not those in which supply is adequate but a means of fueling its production is in disfavor.").

[109] 16 U.S.C. § 824a(a) (seeking "abundant supply of electric energy" by directing the federal government to "divide the country into regional districts for the voluntary interconnection and coordination of facilities for the generation, transmission, and sale of electric energy") & 824a(b)

promotion of the coordination of electric facilities" comprises the following: in subsection (a), an instruction to establish a general framework meant to facilitate "coordination by voluntary action;" in subsection (b), "limited authority to compel interstate utilities to connect their lines and sell or exchange energy," subject to defined procedural and substantive requirements, when "interconnection cannot be secured by voluntary action;" and in subsection (c), "much broader" but "temporary" authority "to compel the connection of facilities and the generation, delivery, or interchange of energy during times of war or other emergency."[110]

That tiered structure—relying on voluntary action for quotidian energy planning, specifying limited authority where that voluntary system fails, and allowing for "temporary" central command-and-control only in case of "emergency"—requires that Section 202(c) remain narrowly bounded to instances of an immediate and unavoidable "break-down in electric supply,"[111] rather than mere want of more abundant supply in the future.[112] Interpreting Section 202(c)'s "emergency" powers to encompass longer-term concerns—e.g., potential shortfalls years into the future, or an expected "expansion of artificial intelligence data centers and an increase in domestic manufacturing,"[113]—would unwind the careful balance of voluntary, market-driven action and federal power set out in subsections 202(a) and 202(b). Such an interpretation cannot be squared with the statutory text and structure.[114]

*b. Congress' Enactment of a Specific, Cabined Scheme to Address Reliability Concerns Confirms that Section 202(c) Cannot be Expanded to Impose Requirements Related to Long-Term Reliability.*

That the Department's Section 202 powers may not be used to enforce the Department's view of long-term reliability needs is confirmed by Section 215 of the Federal Power Act—which specifically and directly delineates the scope of federal power to enforce mandatory long-term reliability requirements for the bulk-power system.[115] Congress added Section 215 to the Federal Power Act in 2005 precisely because the Act as it then existed—including Section 202—did not provide the

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(allowing federal government to order "physical connection … to sell energy or to exchange energy" upon application, and after an opportunity for hearing).

[110] S. Rep. No. 74-621 at 49 (1935).

[111] *Id.*

[112] *cf.* Eddystone 202(c) Order, Ex. 9 at 2 (imposing responsibility on PJM "to ensure maximum reliability on its system").

[113] Grid EO at Sec. 1 (RAR, Ex. 1 at C-4).

[114] *See Otter Tail Power Co. v. Fed. Power Comm.*, 429 F.2d 232, 233-34 (1970) (holding that Section 202(c) "enables the Commission to react to a war or national disaster," while Section 202(b) "applies to a crisis which is likely to develop in the foreseeable future").

[115] 16 U.S.C. § 824o.

federal government with the power to enforce measures designed to ensure broad, long-term reliability.[116]

By enacting Section 215, Congress provided a comprehensive and carefully circumscribed scheme to empower the federal government to enforce long-term reliability requirements. That statutory scheme strikes a careful balance between state and federal authority, and between private, market-driven decisions and top-down control. Reliability standards are devised by NERC independent "of the users and operators of the bulk-power system" but with "fair stakeholder representation."[117] FERC may approve or remand those standards (but not replace them with its own) and is required to "give due weight" to NERC's "technical expertise" while independently assessing effects on "competition."[118] Section 215 provides specified enforcement mechanisms and procedures for reliability standards—which mechanisms conspicuously exclude the power to command specific generation resources to remain operational.[119] And Section 215 carefully preserves state authority over "the construction of additional generation" and in-state resource adequacy, establishing regional advisory boards to ensure appropriate state input on the administration of reliability standards.[120]

Interpreting Section 202(c) to permit the Department to mandate generation based on its own unfettered assessment of long-term bulk-system reliability would effectively allow the Department to bypass Section 215's procedural safeguards, constraints on federal authority, and protection of state power. Such a bypass would impermissibly "contradict Congress' clear intent as expressed in its more recent," reliability-specific "legislation," enacted "with the clear understanding" that the Department had "no authority" to address long-term reliability through Section

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[116] *See* 70 Fed. Reg. 53,118 ("In 2001, President Bush proposed making electric Reliability Standards mandatory and enforceable," leading to enactment of Section 215 in 2005); RAR of the National Energy Policy Development Group (May 2001) at p. 7-6, https://www.nrc.gov/docs/ml0428/ml042800056.pdf (noting that "[r]egional shortages of generating capacity and transmission constraints combine to reduce the overall reliability of electric supply in the country" and that "one factor limiting reliability is the lack of enforceable reliability standards" because "the reliability of the U.S. transmission grid has depended entirely on *voluntary* compliance," and then recommending "legislation providing for enforcement" of reliability standards (emphasis added)); S. Rep. No. 109-78 at 48 (2005) (Section 215 "changes our current voluntary rules system" for long-term reliability "to a mandatory rules system."). *See Alcoa, Inc. v. FERC*, 564 F.3d 1342, 1344 (D.C. Cir. 2009) (noting that prior to the Energy Policy Act of 2005, "the reliability of the nation's bulk-power system depended on participants' voluntary compliance with industry standards").

[117] 16 U.S.C. § 824o(c)-(d). *See also id.* 824o(a)(3) (defining reliability standards as "a requirement … to provide for reliable operation of the bulk-power system").

[118] *Id.* § 824o(d)(2)-(4).

[119] *Id.* § 824o(e).

[120] *Id.* § 824o(i)-(j).

202(c).[121] Congress has, in Section 215, directly established the mechanisms (and limitations) by which the federal government may compel action to ensure long-term electric-system reliability. In so doing, it has confirmed that the Department may not, through Section 202(c) "emergency" orders, use long-term reliability concerns to mandate the generation it views as required to address long-term reliability needs.

*c. DOE's Regulations Similarly Establish that Section 202(c) Emergency Authority Can Only Be Invoked to Address Imminent, Certain Supply Shortfalls Requiring Immediate Response.*

The Department's regulations demonstrate its own long-standing understanding that Section 202(c)'s authority is confined to imminent and unavoidable resource shortages, rather than a mechanism to address long-term concerns as to the reliability of the bulk-power system. The regulations define an emergency as "an *unexpected* inadequate supply of electric energy which may result from the *unexpected* outage or breakdown" of generating or transmission facilities—not a means of planning against distant expectations or risks.[122] Emergencies "may result" from a number of events.[123] The use of the verb "result," defined as "arise as a consequence, effect, or conclusion," suggests that the event triggering the emergency has already happened rather than that there is a speculation that it could occur.[124]

Moreover, the events are characterized by those produced by "weather conditions, acts of God, or unforeseen occurrences not reasonably within the power of the affected 'entity' to prevent."[125] Where the culprit is increased demand, it must be "a *sudden* increase in customer demand" producing a "*specific* inadequate power supply situation,"[126] rather than long-term demand projections producing general reliability concerns. The need for both specificity and certainty is repeated in the Department's regulations defining an inadequate energy supply: "A system may be considered to have" inadequate supply when "the projected energy deficiency . . . *will* cause the applicant [for a 202(c) Order] to be unable to meet its

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[121] *See FDA v. Brown & Williamson Tobacco Corp.*, 529 U.S. 120, 142 & 149 (2000); s*ee also Cal. Indep. Sys. Operator Corp. v. FERC*, 372 F.3d 395, 401–02 (D.C. Cir. 2004) ("Congress's specific and limited enumeration of [agency] power" over a particular matter in one section of the Federal Power Act "is strong evidence that [a separate section] confers no such authority on [agency].").

[122] 10 C.F.R. § 205.371 (emphasis added).

[123] *Id.* ("may result from the unexpected outage," "may be the result of weather conditions," "can result from a sudden increase in customer demand").

[124] Merriam-Webster's Collegiate Dictionary (11th ed. 2003) 1063.

[125] 10 C.F.R. § 205.371

[126] *Id.* (emphasis added).

normal peak load requirements based upon use of all of its otherwise available resources so that it *is* unable to supply adequate electric service to its customers."[127]

And while the regulations suggest that "inadequate planning or the failure to construct necessary facilities *can result* in an emergency," they recognize that the Department may not utilize a "continuing emergency order" to mandate long-term system planning.[128] An emergency may exist where past planning failures produce an immediate, present-tense shortfall (that is where, a shortfall *results* from insufficient planning); the Department has no authority to commandeer bulk-system reliability planning merely because it deems current plans inadequate to meet far-distant needs.[129] As the Department stated when it promulgated those regulations, the statute allows the Department to provide "assistance [to a utility] during a period of unexpected inadequate supply of electricity," but does not empower it to "solve long-term problems."[130]

*d. Courts Have Uniformly Held that Section 202(c) Can Be Invoked Only in Immediate Crises.*

Two courts have addressed the scope of authority under Section 202(c), and both determined that this Section applies only when there is a sudden, unexpected, imminent, and specific emergency.

*Richmond Power and Light of City of Richmond, Indiana v. FERC*, 574 F.2d 610 (D.C. Cir. 1978), arose out of the 1973 oil embargo. The Federal Power Commission needed to decide how to respond to oil shortages, and decided to call for the voluntary transfer for electricity from non-oil power plants to areas of the country that relied heavily on oil, such as New England.[131] The New England Power Pool was not convinced that the voluntary program would work and petitioned the Commission for a 202(c) order.[132] The Commission instead facilitated an agreement between state commissions and supplying utilities, which satisfied the New England Power Pool and it withdrew its petition.[133] A dissatisfied utility

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[127] 10 C.F.R. § 205.375 (emphasis added).

[128] 10 C.F.R. § 205.371 (also recognizing that "where a shortage of electricity is projected due solely to the failure of parties to agree to terms, conditions, or other economic factors" there is no emergency "unless the inability to supply electric service is *imminent*" (emphasis added)).

[129] *See* 10 C.F.R. § 205.375 (requiring present inability to meet demand to demonstrate inadequate energy supply).

[130] 46 Fed. Reg. at 39,985–86.

[131] 574 F.2d at 613.

[132] *Id.*

[133] *Id.*

sought judicial review of the Commission's decision to allow the withdrawal of the Section 202(c) petition.[134]

The court easily upheld the Commission's decision not to invoke Section 202(c).[135] Though the oil embargo had ended, the utility argued that the "high cost and uncertain supply of imported oil" justified an emergency order.[136] The Commission countered that the voluntary program had worked, the New England Power Pool never interrupted service, there was no need for a Section 202(c) order, and the court agreed.[137]

Trying another tactic, the utility argued that "dependence on imported oil leaves this country with a *continuing* emergency."[138] The court observed that Section 202(c) "speaks of 'temporary' emergencies, epitomized by wartime disturbances."[139] Interpreting this statutory language, the court upheld the Department's view that Section 202(c) cannot be used when "supply is adequate but a means of fueling its production is in disfavor."[140] Section 202(c) is not an appropriate means to implement long-term national policy to switch fuels. It is only a temporary fix for a temporary problem.

The Eighth Circuit has similarly held that Section 202(c) can only be used to respond to immediate crises. In *Otter Tail Power Co. v. Federal Power Commission*, 429 F.2d 232 (8th Cir. 1970), a utility insisted that the only way for the Federal Power Commission to properly order the utility to connect to a municipal power provider was to issue a Section 202(c) order. Demand for electricity in the city had increased, and the peak load of the municipal power provider was getting to be so high that both of its two generators would likely need to be used simultaneously in the near future, "causing a possible loss of service should one malfunction during a peak period."[141] To avoid this possible loss of service, the Federal Power Commission issued a Section 202(b) order, requiring the utility to connect the municipal power provider. The utility argued that the Federal Power Commission used the wrong section and should have used Section 202(c) instead.

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[134] *Id.* at 614.

[135] *Id.*

[136] *Id.*

[137] *Id.* at 615.

[138] *Id.* (emphasis added).

[139] *Id.*

[140] *Id.*

[141] *Id.* at 233-34.

The court explained that Section 202(c) "enables the Commission to react to a war or national disaster" by ordering "immediate" interconnection during an "emergency."[142] For non-emergency situations, "[o]n the other hand, Section 202(b) applies," including when there is a "crisis which is likely to develop in the foreseeable future but which does not necessitate immediate action on the part of the Commission."[143] The court upheld the Commission's use of Section 202(b) instead of Section 202(c) because there was no immediate emergency.

The case law uniformly supports the interpretation that Section 202(c) can only be used in acute, short-term, urgent emergencies.

*e. The Department's Prior Orders Recognize that Section 202(c) Does Not Confer Plenary Authority Over Long-Term Resource Adequacy.*

The Department's past applications of Section 202(c) corroborate the urgency of the emergency conditions that are the necessary predicate for any Department intervention under that section.[144] The Department's predominant practice outside of wartime has been to use Section 202(c) to address specific, imminent, and unexpected shortages—not to address longer-term reliability concerns or demand forecasts.[145] The Department has also narrowly tailored the remedies in Section 202(c) orders to ensure that the orders only address the stated emergency, to limit the order to the minimum period necessary, and to mitigate violations of environmental requirements and impacts to the environment.[146]

Public Interest Organizations are not aware of any instance in which the Department has utilized Section 202(c) to mandate generation the Department

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[142] *Id.* at 234 (citing 16 U.S.C. § 824a(c)).

[143] *Id.*

[144] *See FTC v. Bunte Brothers, Inc.*, 312 U.S. 349, 352 (1941) ("[J]ust as established practice may shed light on the extent of power conveyed by general statutory language, so the want of assertion of power by those who presumably would be alert to exercise it, is equally significant in determining whether such power was actually conferred.").

[145] *See, e.g.,* Ex. 5, Dep't of Energy Order No. 202-22-4 (Dec. 24, 2022) (responding to ongoing severe winter storm producing immediate and "unusually high peak load" between Christmas Eve and Boxing Day); Ex. 6 Dep't of Energy Order 202-20-2 (Sept. 6, 2020) at 10-2 (responding to shortages produced by ongoing extreme heat and wildfires); *see also* Ex.7 Rolsma, 57 Conn. L. Rev. at 803-4 (describing "sparing[]" use of Section 202(c) outside of war-time shortages during the twentieth century).

[146] *See, e.g.*, Ex. 5, Dep't of Energy Order No. 202-22-4 (Dec. 24, 2022) at 4-7 (limiting order to the 3 days of peak load, directing PJM to exhaust all available resources beforehand, requiring detailed environmental reporting, notice to affected communities, and calculation of net revenue associated with actions violating environmental laws); Ex. 6 Dep't of Energy Order 202-20-2 (Sept. 6, 2020) at 3-4 (limiting order to the 7 days of peak load, directing CAISO to exhaust all available resources beforehand, requiring detailed environmental reporting).

views as necessary to ensure long-term resource sufficiency—and for good reason.[147] Any such use would exceed the Department's statutory authority.

2. In the RAR, DOE purports to identify only long-term, uncertain, and generalized concerns with bulk-power system reliability, which do not enable the Department to compel generation pursuant to Section 202(c).

Given the statutory limitations described above, the RAR provides no basis for the Department to use Section 202(c) to require that particular "generation resources" are "retained as an available generation resource," or to "prevent . . . an identified generation resource . . . from leaving the bulk-power system or converting" its fuel source.[148] Nor does the Department identify any other source of legal authority for DOE to impose such requirements. In the RAR, the Department only purports to identify capacity shortages that might affect bulk-system reliability in 2030.[149] The Department acknowledges that all but one region—ERCOT—currently meet its criteria.[150] Its claim that shortages might arise five years from now, even if it were correct—would present no "emergency" under Section 202(c). Those non-imminent resource needs are, rather, precisely the long-term reliability and resource adequacy matters over which Congress allocated responsibility to FERC and NERC.

Second, the Department identifies only a "risk of power outages" even in 2030[151] based on the Department's projected "AI and data center load growth under the given assumptions for generator build outs by 2030, generator retirements by 2030, reserve requirements, and potential load growth."[152] The Department acknowledges, meanwhile that its analysis "is not an indication that reliability coordinators would allow this level of load growth to jeopardize the reliability of the system."[153] The RAR—even by its own terms—thus does not specify any shortfall that is certain enough to justify invocation of the Department's emergency powers under Section 202(c). Its numbers are, rather, "indicators to determine where it may be beneficial to encourage increased generation and transmission capacity to meet an expected need."[154] Section 202(c) does not authorize the Department to order generation based on such non-certain shortfalls; it provides distinct, and

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[147] *See Richmond Power and Light,* 574 F.2d at 616.

[148] Grid EO at 2.

[149] *E.g.,* RAR, Ex. 1 at 1, 20, 27, 30, 32, 40.

[150] RAR, Ex. 1 at 7.

[151] *Id.* at 1.

[152] *Id.* at 7.

[153] *Id.*

[154] *Id.*

much more limited powers, by which the Department may facilitate "an abundant supply of electric energy throughout the United States."[155]

And third, the Department does not claim to identify any particular location in which a shortfall might occur, or the specific resources that might best serve to address such shortfall. Instead, in the RAR, the Department provides aggregate estimates of potential loss-of-load under "varied grid conditions and operating scenarios based on historical data."[156] But those estimates do not demonstrate that any single generating facility would best meet the resulting shortfall, and could not therefore justify an emergency order directing a facility to remain available.

Consequently—even setting aside methodological flaws—the Department asserts resource risks in the RAR that are neither imminent, certain, nor specific. Those risks do not describe an emergency that would permit the Department to intervene pursuant to Section 202(c). They represent, rather, the Department's view as to measures that might "assur[e] an abundant supply of electric energy throughout the United States."[157] Section 202 does not permit the Department to compel generation on that basis. The Department also describes in the RAR the measures the Department believes "necessary to provide for reliable operation of the bulk-power system."[158] But Section 215 gives FERC, not the Department, the power to provide for reliable operation of the bulk power system, and specifies the procedures by which such measures must be developed and enforced; the Federal Power Act does not permit the Department to end-run those limitations by deeming long-term reliability an emergency. The RAR consequently could not form the basis of any action by the Department to compel generation under Section 202 of the Federal Power Act.

### C. The RAR Is Analytically Flawed and Does not Rely Upon Substantial Evidence.

The RAR is severely flawed and does not meet DOE's own information quality standards. There are significant informational and methodological limitations and clear analytical and data errors. Any reliance on the RAR to "guide interventions" or to serve as a basis for any DOE decisionmaking would be arbitrary and capricious and not based on substantial evidence, in violation of the Administrative Procedure Act.

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[155] 16 U.S.C. § 824a(a).

[156] RAR, Ex. 1 at 2. *See, e.g., id.* at 21.

[157] 16 U.S.C. § 824a(a).

[158] 16 U.S.C. § 824o(a)(3).

1. The RAR falls woefully short of informational and methodological best practices.

DOE admits the RAR was hastily thrown together without sufficient information. At the outset, DOE acknowledges the resource adequacy analysis in the RAR "could benefit greatly from the in-depth engineering assessments which occur at the regional and utility level."[159] Indeed, "[h]istorically, the nation's power system planners would have shared electric reliability information with DOE through mechanisms such as EIA-411, which has been discontinued."[160] DOE continues to explain that a key takeaway of the RAR is the need for "strengthened regional engagement, collaboration, and robust data exchange which are critical to addressing the urgency of reliability and security concerns that underpin our collective economic and national security."[161] The candor in these comments is revealing; these limitations prove that the RAR does not meet the requirements of the Information Quality Act ("IQA") or DOE's guidelines thereunder.[162] The RAR should be withdrawn so that the Department does not continue to disseminate this poor-quality information, and the RAR should not be relied on in any decisionmaking. In the alternative, the Department should not use the RAR as support for any final action until and unless it (1) provides notice of the statutory authority under which DOE issued the RAR and publishes all data underlying the RAR, (2) explains in detail the specific uses for the methodology, and (3) allows interested parties to comment on the RAR before releasing a final version that incorporates and responds to public comment.

The IQA directs agencies to "ensur[e] and maximiz[e] the quality, objectivity, and integrity of information (including statistical information) disseminated by Federal Agencies."[163] Office of Management and Budget ("OMB") guidelines issued

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[159] RAR, Ex. 1 at i.

[160] *Id.*

[161] *Id.*

[162] *See* Pub. L. 106-554 Sec. 515, 114 Stat. 2763A-153.

[163] *Id.* OMB's government-wide information quality guidelines direct agencies to issue their own implementing guidelines. Agencies must provide the public a way to administratively seek and obtain correction of information disseminated by the agency that does not comply with OMB or agency guidelines. *See* Office of Management and Budget, Guidelines for Ensuring and Maximizing the Quality, Objectivity, Utility, and Integrity of Information, 67 Fed. Reg 8452 (Feb. 22, 2002); Office of Management and Budget, Memorandum for the Heads of Executive Departments and Agencies (Apr. 24, 2019) (hereinafter "OMB Guidelines 2019 Update"), https://www.whitehouse.gov/wp-content/uploads/2019/04/M-19-15.pdf.

Pursuant to the OMB directive, DOE has issued its own agency-specific information quality guidelines. *See* Dep't of Energy, Final Report Implementing Office of Management and Budget Information Dissemination Quality Guidelines (Oct. 1, 2002), no. 6450-01-p, https://www.energy.gov/sites/prod/files/cioprod/documents/finalinfoqualityguidelines03072011.pdf; Dep't of Energy, Final Report Implementing Updates to the Department of Energy's Information

pursuant to the IQA require agencies to ensure that scientific information including "factual inputs, data, models, analyses . . . related to such disciplines as . . . engineering, or physical sciences" undergo certain review procedures to maintain quality standards.[164]

To that end, agencies must "choose a peer review mechanism that is adequate, giving due consideration to the novelty and complexity of the science to be reviewed, the relevance of the information to decisionmaking, the extent of prior peer reviews, and the expected benefits and costs of additional review."[165] Agencies must "strive to ensure that their peer review practices are characterized by both scientific integrity and process integrity," including the "rationale and supportability" of the agency's findings and ensuring "avoidance of real or perceived conflicts of interest" and "a workable process for public comment and involvement."[166] Agencies are encouraged to "have the choice of input data and the specification of the model reviewed by peers before the agency invests time and resources in implementing the model and interpreting the results," in order to "focus attention on data inadequacies in time for corrections . . . before the agency becomes invested in a specific approach."[167] Additionally, peer reviewers must "ensure that scientific uncertainties are clearly identified and characterized," and "ensure that the potential implications of the uncertainties for the technical conclusions drawn are clear."[168] OMB IQA guidelines also require agencies to evaluate "the sensitivity of the agency's conclusions to analytic assumptions."[169] These steps of peer review determine a report's "fitness . . . for policy purposes."[170]

DOE IQA guidelines further note that "in disseminating certain types of information to the public, other information must also be disseminated in order to ensure an accurate, clear, complete, and unbiased presentation."[171] Agencies should provide open access to data and modeling information underlying a report.[172]

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Quality Act Guidelines (2019) (hereinafter "DOE IQA Guidelines 2019 Update"), available at https://www.energy.gov/cio/articles/2019-final-updated-version-doe-information-quality-guidelines.

[164] OMB, Final Information Quality Bulletin for Peer Review, 70 Fed. Reg. 2664, 2667 (Jan. 14, 2005); *see also* OMB Guidelines 2019 Update at 4.

[165] OMB Information Quality Bulletin for Peer Review, 70 Fed. Reg. at 2668.

[166] *Id.*

[167] *Id.*

[168] *Id.* at 2669.

[169] OMB Guidelines 2019 Update at 4.

[170] *Id.*

[171] DOE IQA Guidelines 2019 Update at 16.

[172] OMB Guidelines 2019 Update at 8; *See also*, e.g., *Chem. Mfrs. Ass'n v. U.S. EPA*, 870 F.2d 177, 200 (5th Cir. 1989) ("fairness requires that the agency afford interested parties an opportunity to challenge the underlying factual data relied on by the agency."); *United States v. Nova Scotia Food*

Additionally, DOE is "responsible for ensuring that the information [being disseminated in a report] is consistent with the OMB and DOE guidelines and that the information is of adequate quality for dissemination."[173] For reports containing "influential financial, scientific, or statistical information," DOE must "identify for the [Chief Information Officer] a high ranking official" who is responsible for higher level review of the report's conclusions.[174]

OMB's IQA guidelines recognized that the "[f]ederal government's assessment of risk can directly or indirectly influence the response actions of state and local agencies or international bodies."[175] Thus, under the OMB and DOE guidelines, influential information—information routinely embargoed because of "potential effect on markets" or information "on which a regulatory action with a $100 million per year impact is based"—must meet the highest standards of quality and transparency, and should undergo the rigorous review procedures outlined above.[176]

Here, the RAR does not comply with IQA requirements, rendering any further reliance on it to be arbitrary and capricious. For example, the RAR appears to be inconsistent with internal review processes required: it should have undergone peer review because of its "influential" nature, particularly if the RAR is, as it purports to be, a "uniform methodology" to guide reliability interventions, such as Federal Power Act Section 202(c) orders, which have outsize economic impacts. However, there is no evidence that the RAR underwent any peer review, and, given the time constraints, it is unlikely it did. The Department further failed to make available all underlying data and modeling information used to create the RAR. Additionally, as described in detail below, the RAR relies on improper analytic assumptions, including overstated demand and understated supply forecasts. The RAR includes faulty analysis based on these improper assumptions despite DOE's acknowledgment of significant informational limitations regarding regional- and utility-level engineering data. In addition, the RAR contains numerous errors, such as referring to appendices that do not exist or incorrect appendices,[177] stating

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*Prods. Corp.*, 568 F.2d 240, 251-53 (2d Cir. 1977) (holding that regulation was promulgated in arbitrary and capricious manner where agency failed to disclose data on which it relied).

[173] DOE IQA Guidelines 2019 Update at 22.

[174] *Id.* at 22-23.

[175] OMB Information Quality Bulletin for Peer Review, 70 Fed. Reg at 2667.

[176] DOE IQA Guidelines 2019 Update at 7.

[177] *See* RAR, Ex. 1, at 12 (referring to nonexistent "Outputs" section of an unnamed appendix); *id.* (referring to Appendix B for further detail regarding retirement assumptions, whereas Appendix B describes Canadian transfer limits).

inaccurate units for generation capacity,[178] and falsely asserting bulk power system load shedding occurred in regions during certain events.[179]

2. In the RAR, the Department overstates assumptions about demand.

In the RAR, the Department assumes 101 GW of load growth by 2030—a 15% increase over 2025 load. This increase is more than double the high case in the U.S. EIA 2025 Annual Energy Outlook, which forecasts 6% growth.[180] This extraordinarily high assumed load growth contributes substantially to the findings of low resource adequacy under the Plant Closures scenario in the RAR. As explained below, in the RAR, the Department omits consideration of many factors that will likely dampen load growth in the coming 5 years, thus undermining the validity and usefulness of its results.

The Department assumes 50 GW of load growth from data centers by 2030, which it characterizes as the midpoint among other available forecasts.[181] However, it does not appear that DOE's forecast accounts for load flexibility at these data centers, which would significantly reduce the overall demand that these centers place upon the grid during the periods of peak system risk. While certain data centers may not be capable of load curtailment due to their purpose, many can be flexible. Even a small amount of data center load flexibility provides significant benefits. A recent study by experts at Duke University found that curtailment at data centers during only 0.25% of the year would enable 76 GW of data center power demand to be added to the system today, without triggering resource adequacy problems or requiring further expansion.[182] The White House recently issued an AI Action Plan endorsing demand flexibility as a means to maintain resource adequacy as data center capacity expands: "the United States should investigate new and novel ways for large power consumers to manage their power consumption during critical grid periods to enhance reliability and unlock additional power on the system."[183]

The Electric Power Research Institute has begun an initiative to enhance data center flexibility in light of its benefits for grid reliability, under which

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[178] *Id.* at 9 (text stating that PJM has a shortfall of 2.4 MW).

[179] *See infra* subsection C.6.

[180] *See* GridLab Analysis, Ex. 14 at 2.

[181] RAR, Ex. 1 at 2.

[182] Norris, T. H., T. Profeta, D. Patino-Echeverri, and A. Cowie-Haskell. 2025. Rethinking Load Growth: Assessing the Potential for Integration of Large Flexible Loads in US Power Systems at 20. Durham, NC: Nicholas Institute for Energy, Environment & Sustainability, Duke University, https://nicholasinstitute.duke.edu/publications/rethinking-load-growth (attached as Ex. 15).

[183] White House, Winning the Race: America's AI Action Plan 15 (July 2025), https://www.whitehouse.gov/wp-content/uploads/2025/07/Americas-AI-Action-Plan.pdf.

demonstration projects were set to deploy in the first half of 2025.[184] Early results from other projects to test data center flexibility have been promising.[185] Evaluations of the RAR by GridLab and the NYU Institute for Policy Integrity ("IPI") both have concluded that the Department's failure to account for data center load flexibility renders its findings of elevated reliability risk in 2030 suspect.[186] This is particularly true for DOE's findings concerning the ERCOT region, considering that in June 2025, Texas enacted a law allowing curtailment of these loads during grid emergencies.[187]

Furthermore, it is unclear whether the RAR's data center load forecasts account for potential constraints on the growth of data centers, such as shortages of critical semiconductor chips,[188] and other grid equipment like transformers and switchgears.[189] In addition to the Texas policy mentioned above, states and utilities are proposing new tariff designs for data centers to ensure that data centers don't

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[184] Elec. Power Rsch. Inst., EPRI Launches Initiative to Enhance Data Center Flexibility and Grid Reliability (Oct. 29, 2024), https://perma.cc/75LY-PSP5 ("Led by EPRI, DCFlex will coordinate real-world demonstrations of flexibility in a variety of existing and planned data centers and electricity markets, creating reference architectures and providing shared learnings to enable broader adoption of flexible operations that benefit all electricity consumers. Specifically, DCFlex will establish five to ten flexibility hubs, demonstrating innovative data center and power supplier strategies that enable operational and deployment flexibility, streamline grid integration, and transition backup power solutions to grid assets. Demonstration deployment will begin in the first half of 2025, and testing could run through 2027.").

[185] *See* Anuja Ratnayake, Unlocking AI Potential with Data Center Flexibility, ENERGYCENTRAL (June 12, 2025), https://www.energycentral.com/intelligent-utility/post/unlocking-aipotential-with-data-center-flexibility-PtPoXIAuRMzs5Ff ("In a preliminary test of the depth of computational flexibility possible in an AI data center, the Arizona demonstration site experienced some early success. It showcased the potential for an AI data center to provide grid relief during a peak system event—such as a hot summer day with high power demand—by temporarily and precisely ramping down its electricity consumption without compromising data center performance.").

[186] NYU Institute for Policy Integrity, *Enough Energy*, at 25 (attached as Ex. 16) (hereinafter "IPI Report"); *see also* GridLab Analysis, Ex. 14 at 2 ("It does not address flexibility of this load, however, which was recently demonstrated in a report from Duke University to allow for 100 GW of large load additions today with minimal grid impact.").

[187] S.B. No. 6 § 4, 89th Legislature (Tex. 2025) (to be enacted at Tex. Util. Code § 39.170), https://perma.cc/4Z7H-9XKQ; Brian Martucci, Texas Law Gives Grid Operator Power to Disconnect Data Centers During Crisis, UTILITY DIVE (June 25, 2025), https://perma.cc/SYK3-V4XX; Waleed Aslam & Robin Hytowitz, Elec. Power Rsch. Inst., Texas SB6 Explained: Addressing Large Load Impacts (2025), https://perma.cc/QD8S-3M5C.

[188] *See, e.g.* London Economics International LLC, *Uncertainty and Upward Bias Are Inherent in Data Center Electricity Demand Projections* at 39 (July 7, 2025) (attached as Ex. 17), https://www.selc.org/wp-content/uploads/2025/07/LEI-Data-Center-Final-Report-07072025-2.pdf.

[189] How big tech plans to feed AI's voracious appetite for power, The Economist (July 28, 2025), https://www.economist.com/business/2025/07/28/how-big-tech-plans-to-feed-ais-voracious-appetite-for-power.

pose risks to the distribution system or shift costs to other consumers, all of which could slow or redirect the forecasted data center load growth.[190] The Department fails to evaluate any of these dynamics in the RAR.

In addition to the overall rate of data center load growth, the Department also uses a poorly described and supported methodology to allocate data center load to different regions. As the IPI observes, DOE used state-level growth ratios to allocate the projected data center load across regions, "[b]ut it is unlikely that all the computing demand needs to be processed close to load centers (i.e., proportional to a region's current electric load)."[191] IPI posits that "some computing demand may be served from other regions if it will be cheaper to integrate the data center elsewhere," and observes that "[g]iven the scale of DOE's projected data center load compared to the relatively small resource adequacy shortfalls that the study identifies, these assumptions may have made the difference between whether a region achieves DOE's resource adequacy targets."[192] Figure 8 in the RAR (New Data Center Build) shows that DOE's estimates for the percentage of data center load growth that will be built in various RTOs in some cases differs substantially from the percentages in the various forecasts that DOE used to calculate its overall data center load growth estimate. DOE does not explain why it discards these studies' more geographically specific estimates and instead relies on a single state-level growth ratio derived from a different study.

The Department's approach to estimating non-data center load growth by 2030 is also poorly explained in the RAR and likely flawed. DOE relies upon NERC's 2024 Long-Term Reliability Assessment forecast for overall load growth, but because the Department otherwise seeks to include elevated levels of data center load growth in the RAR, it must back out an estimate of data center load growth from the overall forecast.[193] The estimate that DOE chooses to back out is a "low-growth" case for data center load from a different source (which DOE presents in volumetric consumption terms, rather than peak demand). This approach, without further information to understand DOE's analysis, could have resulted in DOE over-estimating non-data center load growth. This effect is likely exacerbated by recent changes in federal law that will reduce electricity consumption from

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[190] Jason Plautz, *Rulemakers play catch-up as data centers multiply*, E&ENews by Politico (July 18, 2025), https://www.eenews.net/articles/rulemakers-play-catch-up-as-data-centers-multiply/.

[191] IPI Report, Ex. 16 at 26.

[192] *Id.*

[193] RAR, Ex. 1 at 17 ("Given the rapid emergence of AI/DC loads, additional steps were taken to account for this category of demand. It is difficult to determine how much AI/DC load is already embedded in NERC [Long-Term Reliability Assessment] forecast, for example, the 2024 [Long-Term Reliability Assessment] saw more than 50GW increase from 2023, signaling a major shift in utility expectations. To benchmark existing AI/DC contribution, DOE assumed base 2023 AI/DC load equaled the EPRI low-growth case of 166 TWh.").

specific sectors, including vehicles and hydrogen electrolysis. The utility forecasts included in the NERC Long-Term Reliability Assessment included projections of vehicle and building electrification that depend in part on tax credits and incentives that were revoked prior to publication of the RAR as part of the One Big Beautiful Bill Act ("OBBBA"). Recent analysis shows that the elimination or reduction of tax credits that supported new sources of electricity load growth will have a meaningful effect by 2030.[194] As a result, DOE's non-data center load growth projections are likely overstated.

3. Assumptions about supply are unsupported.

*a. In the RAR, the Department Overstates Likely Retirements.*

The Department finds the most dire resource adequacy shortfalls occur in the Plant Closures case, in which it assumes 104 GW of retirements by 2030.[195] This estimate is much higher than the most recent data from the EIA released in June 2025 in its authoritative Form 860, which shows 50 GW fewer retirements than assumed in the RAR.[196] As GridLab experts explained, DOE assumed not only "these 50 GW of likely retirements, but [also] included another 50 GW of *announced* retirements."[197] While it may be appropriate to include announced retirements in certain long-term planning exercises, it is unreasonable to assume such retirements will happen as the basis for extraordinary emergency actions. Without more detail about any formal or binding characteristics of those announcements, or the factors purportedly driving those announcements, it is impossible to verify the validity of this input that doubles the amount of otherwise projected resource retirements. Even EIA's Annual Energy Outlook, which does model projected retirements beyond those already formally noticed, finds 10 GW fewer thermal retirements by 2030 than does DOE.[198] Without further support for the 50 GW assumed retirement

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[194] *See, e.g.,* Princeton NetZero Lab and Evolved Energy Research, A Fork in The Road: Impacts of Federal Policy Repeal on the U.S. Energy Transition, at Tab 12 (last updated July 3, 2025), https://public.tableau.com/app/profile/evolvedenergyresearch/viz/AForkinTheRoad_ImpactsofFederalPolicyRepealontheU_S_EnergyTransition_June/1Title (showing approximately 100 TWh annual energy use reduction in 2030 compared to mid-range estimates of the status quo ante).

[195] RAR, Ex. 1 at 5.

[196] U.S. EIA, Annual Energy Outlook 2025: Table 9. Electricity generating capacity (March 2025), https://www.eia.gov/outlooks/aeo/data/browser/#/?id=9-AEO2025&region=0-0&cases=ref2025&start=2025&end=2030&f=A&linechart=ref2025-d032025a.4-9-AEO2025&map=&sourcekey=0. *See also* GridLab Analysis, Ex. 14 at 2.

[197] GridLab Analysis, Ex. 14 at 2; *see also* IPI Report, Ex. 16 at 24 (explaining that DOE's "number includes both 'confirmed' retirements—resources that have notified their system operators of their impending retirements and begun the retirement process—and 'announced' retirements—which are publicly stated but not officially noticed.").

[198] According to the U.S. EIA's 2025 Annual Energy Outlook, coal-fired generating capacity is projected to decline by 93.6 GW between 2025 and 2030 in the Reference case, approximately 10

value, the Plant Closures case is nothing more than speculation about what might happen if certain assumptions were to come true.

Such assumptions are particularly unjustified given that, as GridLab notes, "[m]ost likely many plants will choose not to retire due to the changing regulatory and economic landscape."[199] The IPI makes a similar point in their critique of DOE's retirement assumptions, noting that "the economics of energy production have changed since 2024. The combined effect of new demand from data centers and the elimination of federal tax credits for new wind and solar resources improves the financial outlook for thermal resources."[200] As one snapshot of this trend, high capacity prices in the PJM region led to 1.1 GW of resources withdrawing formal deactivation notices since last summer.[201] IPI also observes that the Trump Administration is seeking to rescind or reexamine many federal environmental regulations that would have required thermal resources to make investments reducing their pollution or else retire before 2030, "which could cause resources to delay their retirements."[202]

*b. In the RAR, the Department Understates Likely New Entry by 2030 and Other Sources of Supply.*

Among the most impactful and unsupported assumptions in the RAR is that "only [generation] projects that are very mature in the pipeline (such as those with a signed interconnection agreement) will be built" by 2030.[203] DOE thus constrains its analysis to include only projects designated as Tier 1 in the NERC 2024 Long Term Resource Assessment, which it then maps to Interregional Transfer Capability Study regions. Because Tier 1 includes only resources that are already under construction, have signed construction service agreements, and similar

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fewer GW of retirements than modeled in the DOE report. No other fossil fuel technology shows a net decrease in generating capacity in the 2025 Annual Energy Outlook analysis. U.S. EIA, Annual Energy Outlook 2025: Table 9. Electricity generating capacity (March 2025), https://www.eia.gov/outlooks/aeo/data/browser/#/?id=9-AEO2025&region=0-0&cases=ref2025&start=2025&end=2030&f=A&linechart=ref2025-d032025a.4-9-AEO2025&map=&sourcekey=0.

[199] GridLab Analysis, Ex. 14 at 2.

[200] IPI Report, Ex. 16 at 24.

[201] PJM Inside Lines, PJM Auction Procures 134,311 MW of Generation Resources; Supply Responds to Price Signal (July 22, 2025) https://insidelines.pjm.com/pjm-auction-procures-134311-mw-of-generation-resources-supply-responds-to-price-signal/ ("Since the 2025/2026 Base Residual Auction results were posted on July 30, 2024, 17 generating units totaling approximately 1,100 MW worth of Capacity Interconnection Rights have withdrawn their retirements").

[202] IPI Report, Ex. 16 at 24-25.

[203] RAR, Ex. 1 at 12.

characteristics,[204] this assumption "results in minimal capacity additions beyond 2026."[205] As experts at GridLab observe, the assumption that "no projects are built post 2026, [] is not realistic for a report forecasting to 2030."[206] This is especially true given rising energy prices due to increased demand, which is attracting more investment to the market and driving new construction of generation resources.

The Department also states in the RAR that of these Tier 1 additions, just 22 GWs of generator additions are "firm" (thermal) resources, which severely underestimates new gas generation compared to other projections. According to GridLab, "a more reasonable assumption for forecasted capacity additions is the EIA 860 released in June 2025, which has 35 GW of gas additions, and another 53 GW of batteries [for a total of] 88 GW of firm additions by 2030."[207] Other federal government projections are even higher: EIA's 2025 Annual Energy Outlook projects 90 GWs of new fossil generators added to the system through 2030.[208] 80 GWs of the EIA-projected natural gas growth are in earlier development stages and likely did not meet the 2024 NERC Long-Term Reliability Assessment Tier 1 criteria to be included in the RAR.

As researchers at the IPI conclude, DOE departed from best practice in declining to include any resources classified by NERC as "Tier 2" resources[209] in the overall resource adequacy analysis for 2030, even those at advanced stages of the interconnection process.[210] A reasonable process could have involved "examin[ing]

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[204] *See* IPI Report, Ex. 16 at n.155 (citing NERC, 2024 Long Term Reliability Assessment, 137 (last updated July 15, 2025) https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC_Long%20Term%20Reliability%20Assessment_2024.pdf).

[205] RAR, Ex. 1 at A-5.

[206] GridLab Analysis, Ex. 14 at 3.

[207] *Id.*

[208] According to the U.S. EIA, the policy-neutral reference case projects a 93.29 GW increase in combined cycle, fossil steam, and combustion turbine capacity between 2025 and 2030. U.S. EIA, Annual Energy Outlook 2025: Table 9. Electricity generating capacity (March 2025), https://www.eia.gov/outlooks/aeo/data/browser/#/?id=9-AEO2025&region=0-0&cases=ref2025&start=2025&end=2030&f=A&linechart=ref2025-d032025a.4-9-AEO2025&map=&sourcekey=0.

[209] NERC defines Tier 2 resources as those having one of the following characteristics: "Signed/approved Completion of a feasibility study, Signed/approved Completion of a system impact study, Signed/approved Completion of a facilities study, Requested Interconnection Service Agreement, Included in an integrated resource plan or under a regulatory environment that mandates a resource adequacy requirement (Applies to RTOs/ISOs)." NERC, 2024Long Term Reliability Assessment, 137 (Dec. 2024, updated July 15, 2025) https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC_Long%20Term%20Reliability%20Assessment_2024.pdf.

[210] IPI Report, Ex. 16 at 23.

historical statistics of interconnection queue time by region, resource type, and resource size, along with differentiated queue withdrawal rates, estimating Tier 2 resource additions for each region."[211] For example, for the PJM region, the Independent Market Monitor's analysis shows that 15% of generation projects (on an energy basis) successfully enter service.[212] As of late 2024, PJM had over 44 GW of accredited capacity in its interconnection queue.[213] To assume that none of this capacity would enter service by 2030, as DOE's analysis does, is unreasonable.

Such an analysis should also consider factors pointing towards even faster queue times than those seen in the historical data, given factors now expediting interconnection queues such as implementation of FERC Order 2023, streamlining of tools to better utilize existing points of interconnection (e.g., surplus interconnection service), and various interconnection fast tracks that FERC has recently approved.[214] For example, it is unreasonable for DOE to exclude from consideration the over 9 GW of accredited capacity that PJM selected in May 2025 to participate in its Reliability Resource Initiative—the vast majority of these projects (primarily gas and battery energy storage systems) are committed to be online by 2030,[215] but are omitted in DOE's analysis because they do not yet have a signed interconnection agreement. DOE paints an inaccurate picture of new entry by ignoring recently adopted policies designed to address the very same tightening supply and demand conditions that DOE describes.

DOE also underestimates the extent to which interregional transfers of energy could help to prevent or address any shortfalls. Noting that it relies upon the interregional transfer capacities identified by NERC in its Interregional Transfer Capability Study, DOE explains that "[i]mports are assumed to be available up to the minimum total transfer capacity and spare generation in the

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[211] *Id.*

[212] Monitoring Analytics, 2024 State of the Market Report, at 705 (2024) https://www.monitoringanalytics.com/reports/PJM_State_of_the_Market/2024/2024q2-som-pjm-sec12.pdf (noting 14.9% completion rate).

[213] PJM, Reliability Resource Initiative MRC Update, at slide 6 (Nov. 7, 2024) https://www.pjm.com/-/media/DotCom/committees-groups/committees/mrc/2024/20241107-special/item-04---reliability-resource-initiative---presentation.ashx.

[214] *Id. See also* Prefiled Statement of Manu Asthana on Behalf of PJM Interconnection, L.L.C., FERC Docket No. AD25-7, at 4 (May 27, 2025), https://www.ferc.gov/media/manu-asthana-pjm-president-and-ceo (touting recent improvements to PJM's interconnection queue by noting that "[a]n additional approximately 18 GW is being processed to move to the final study phase for completion this year, and an additional 56 GW (including projects from Transition Cycle 2 and Reliability Resource Initiative) will be through the queue by late 2026.").

[215] PJM, Reliability Resource Initiative Results Summary, at slide 9 (May 6, 2025) https://www.pjm.com/-/media/DotCom/committees-groups/committees/pc/2025/20250506/20250506-item-06---reliability-resource-initiative---summary-results.pdf.

neighboring subregion."[216] Because the Interregional Transfer Capability Study calculated interregional transfer capacities for both summer and winter, and for each direction of flow, it is unclear what DOE means regarding allowing transfers up to the minimum. As the IPI observes: "If DOE picked the lesser of the summer and winter transfer capacities and applied that annually, doing so would inaccurately underestimate the amount of interregional transfer capacity."[217] This is yet another example of where DOE fails to explain its methodology with sufficient detail to enable an evaluation of whether its approach is reasonable, or is supported by substantial evidence.

4. DOE's use of a deterministic analysis provides an incomplete and inaccurate picture.

For the RAR, DOE employs a deterministic approach in examining resource adequacy; that is one that "evaluate[s] resource adequacy using relatively stable or fixed assumptions about the representation of the power system," rather than a probabilistic approach that "incorporate[s] data and advanced modeling techniques to represent uncertainty that require more computing power."[218] DOE explains it chose a deterministic approach "for transparency and to model detailed historic system conditions."[219] However, deterministic approaches have significant limitations; as NERC explained in the Interregional Transfer Capability Study on which DOE otherwise heavily relies, because that study did not employ a probabilistic approach, it "should not be considered a North American resource adequacy assessment."[220] The problem, as IPI explains, is that "[b]y examining whether regions would be resource adequate only under conditions that resemble the recent past, DOE's study does not sufficiently account for uncertainty."[221] Furthermore, as NERC itself has explained, under a deterministic approach, "some regions may look resource adequate because they happened to do well during the twelve years of data, while others look resource inadequate but be unlikely to perform as poorly in the future."[222] As IPI concludes, neither of DOE's professed reasons for using a deterministic approach justifies departing from best practices, as "DOE could document a probabilistic approach in a transparent way, and relying on a small sample of historic years is less accurate than a probabilistic approach."[223]

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[216] RAR, Ex. 1 at 12.

[217] IPI Report, Ex. 16 at 26.

[218] RAR, Ex. 1 at 2 n.2.

[219] *Id.*

[220] IPI Report, Ex. 16 at 21 (citing NERC, Interregional Transfer Capability Study, at 4 (2024) (hereinafter "NERC ITCS")).

[221] IPI Report, Ex. 16 at 21.

[222] *Id.* (citing NERC ITCS at 138).

[223] *Id.* at 21.

DOE may have chosen a less sophisticated and rigorous approach given the limited amount of time in which the Grid EO required this analysis to be completed, but regardless of the reason, the limitations inherent in DOE's deterministic methodology mean that its findings should not be taken as conclusive or form the basis for further extraordinary actions.[224]

5. DOE uses an elevated threshold for determining when outages will occur.

In the RAR, the Department projects a shortfall if "the remaining capacity after transmission and demand response falls below the 6 percent or 3 percent needed for error forecasting and ancillary services, depending on the scenario."[225] This approach, and the particular values used as thresholds, come from the NERC Interregional Transfer Capability Study, which uses 3% as the default threshold and 6% only in a sensitivity analysis. NERC explains that the 3% value "was established based on an evaluation of average reserve requirements where load shed may occur" in order for a Balancing Authority to continue to hold the minimum reserves needed to protect the system from cascading or widespread outages.[226] In the sensitivity examined by NERC, using the 6% threshold "significantly altered the existence and extent of predicted outages in many regions, such as producing a 690% increase in the size of the maximum outage event in SERC-Florida."[227]

As the IPI analysis notes, DOE provides no further explanation for when and how it uses 6% as a threshold versus 3%.[228] While the Department directs readers to an appendix with further detail, the appendices do not in fact provide any further information regarding this critical assumption.[229] Furthermore, "the fact that DOE listed 6% first may suggest that 6% was not limited to a sensitivity analysis," and that if "DOE's model instead identifies shortage events even when a region still has 6% of load available as spare capacity, then DOE's results depart from NERC's practice and may overstate the extent of expected outages."[230] DOE's failure to explain its own methodology concerning such a critical input to its analysis, including through the failure to provide information in an appendix that the RAR states exists, renders the RAR arbitrary and capricious. Insofar as the RAR's results for 2030 scenarios depend upon the 6% threshold, DOE must explain why

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[224] *Id.* ("Given the high stakes associated with resource adequacy planning, any future DOE resource adequacy assessment should prioritize accuracy over expediency.")

[225] RAR, Ex. 1 at 12.

[226] IPI Report, Ex. 16 at 22 (citing NERC ITCS, at 91 n.90, 85).

[227] IPI Report, Ex. 16 at 22 (citing NERC ITCS at 105 tbl.8.4); *see also id.* ("Under the 6% sensitivity, NERC also recommended 58 GW of transmission additions to address resource adequacy instead of 35 GW, illustrating the sizable influence of shifting this assumption from 3% to 6%.")

[228] IPI Report, Ex. 16 at 22.

[229] *Id.*

[230] *Id.*

such a threshold is appropriate, given the departure from NERC's practice and the evidence in the NERC report considering the propriety of a far lower threshold.

6. DOE inconsistently applies its own methodology.

Several of the findings in the RAR are inconsistent with the methodology that DOE develops. For instance, DOE states that "[a]nalysis of the current system shows all regions except ERCOT have less than 2.4 hours of average loss of load per year and less than 0.002% NUSE" (the standards DOE developed for this study).[231] DOE further explains that "[w]hen looking at metrics in the worst weather years, regions meet or exceed additional criteria. All regions experienced less than 20% of lost load in any hour."[232] Despite these clear findings, DOE goes on to state that "PJM, ERCOT, and SPP experienced significant loss of load events during 2021 and 2022 winter storms Uri and Elliot which translated into more than 20 hours of lost load," and asserts that this "results in a concentration of lost load within certain years such that some regions exceeded 3-hours-per-year of lost load."[233] As an initial matter, the PJM system did not experience any lost load due to resource inadequacy during Winter Storms Uri or Elliott.[234] Second, DOE's focus on whether a region had lost load or a risk of lost load in a particular weather year is inconsistent with DOE's own articulation of its resource adequacy standards, as "average indicators" assessed across all scenarios and years.[235] As the IPI notes, these standards are "not a requirement that must be achieved in each and every scenario."[236]

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[231] RAR, Ex. 1 at 7.

[232] *Id.*

[233] *Id. See also Id.* at 9 ("For the current system, this analysis identifies an additional 2.4 MW of capacity to meet the NUSE target for PJM, which experiences shortfalls due to the winter storm Elliot historical weather year.").

[234] PJM Inside Lines, PJM Releases Winter Storm Elliott Report (July 17, 2023) https://insidelines.pjm.com/pjm-releases-winter-storm-elliott-report/ ("PJM maintained system reliability and served customers throughout the extreme weather that affected the region Dec. 23–25 [2022], and even was able to support its neighbors during certain periods."); *see also* FERC, NERC and Regional Entity Staff Report, *The February 2021 Cold Weather Outages in Texas and the South Central United States* (Nov. 16, 2021), https://www.ferc.gov/media/february-2021-cold-weather-outages-texas-and-south-central-united-states-ferc-nerc-and (noting that PJM was exporting power to neighboring regions during Winter Storm Uri, and investigating rolling blackouts only in Texas and south central states).

[235] RAR, Ex. 1 at 5.

[236] IPI Report, Ex. 16 at 20.

### D. Notice and Comment Procedures Are Required for Any "Uniform Methodology" the Department Uses to Guide Reliability Interventions.

Under the Administrative Procedure Act, federal agencies must provide notice and an opportunity for public comment when issuing rules, with limited exceptions not applicable here.[237] If the RAR is, as the Department claims on page vi, a "uniform methodology" for agency decisionmaking on reliability interventions, then the Department needed to provide notice and seek and respond to public comment on this methodology. The Department cannot slip in "entirely new information critical" to its "determination[s]" without taking and responding to public comment.[238]

In the past, when the Department sought to create uniform triggers for reliability intervention within its authority, it issued notice and sought comment.[239] If the RAR is a "uniform methodology" for reliability interventions, then the Department has effectively amended those prior regulations on reliability interventions without following legally required procedures. For example, the Department has regulations defining "emergency" and setting forth procedures for an applicant to demonstrate an "emergency" in the context of Federal Power Act Section 202(c) orders.[240] If the RAR is now a mandatory factor in determining whether there is an "emergency," the Department has changed its existing regulations without following required notice and comment procedures.

### E. NEPA Procedures Must Be Followed for Any RAR on Legislative Proposals or "Uniform Methodology" the Department Uses to Guide Reliability Interventions.

Under the National Environmental Policy Act ("NEPA"), agencies must include a "detailed statement" on the environmental impacts of a proposed action "in every recommendation or report on proposals for legislation and other major Federal actions significantly affecting the quality of the human environment."[241] If the RAR is a "uniform methodology" for agency decisionmaking on reliability interventions, it qualifies as a major federal action requiring, at a minimum, an Environmental Assessment and most likely, under the circumstances, a full

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[237] 5 U.S.C. §§ 553(b), (c).

[238] *Am. Pub. Gas Assoc. v. DOE*, 72 F.4th 1324, 1338 (D.C. Cir. 2023) (cleaned up).

[239] *See* Grid Security Emergency Orders: Procedures for Issuances, 83 Fed. Reg. 1174 (Jan. 10, 2018) (final rule on Federal Power Act section 215A procedures issued after notice and comment); Emergency Interconnection of Electric Facilities and the Transfer of Electricity to Alleviate an Emergency Shortage of Electric Power, 46 Fed. Reg. 39,984 (Aug. 6, 1981) (final rules concerning emergency interconnections under Federal Power Act sections 202(c) and 202(d) issued after notice and comment).

[240] 10 C.F.R. §§ 205.371; 205.373.

[241] 42 U.S.C. § 4332(C).

Environmental Impact Statement. However, the RAR does not contain any statement whatsoever, and certainly no "detailed statement," on environmental impacts.

Yet the RAR purports to guide "government decisionmakers" on one of the most significant issues that affect the environment—electricity generation. The electricity sector is responsible for wide-ranging environmental impacts—from smog to greenhouse gas emissions to toxic metals to acid rain.[242] Uniform rules on reliability interventions would significantly affect the environment because some of these reliability interventions allow environmental rules for electricity generators to be waived.[243]

## VI. CONCLUSION

For the reasons set forth above, the undersigned Public Interest Organizations respectfully request that the Department withdraw the RAR. In the alternative, the Department should not use the RAR as support for any reliability intervention or other action until and unless it (1) provides notice of the statutory authority under which DOE issued the RAR and publishes all data underlying the RAR, (2) provides a detailed explanation of the specific uses for the methodology, and (3) allows interested parties to comment on the RAR before finalizing it.

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[242] *See* EPA, Human Health & Environmental Impacts of the Electric Power Sector (Feb. 6, 2025) https://www.epa.gov/power-sector/human-health-environmental-impacts-electric-power-sector.

[243] *See* 16 U.S.C. § 824a(c)(4)(A).

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BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

| | |
|---|---|
| Federal Power Act Section 202(c) | ) |
| Emergency Order: Tri-State | ) |
| Generation and Transmission | ) |
| Association, Platte River Power | ) |
| Authority, Salt River Project, | ) |
| PacifiCorp, and Xcel Energy | ) |

Exhibit to
Motion to Intervene and Request for Rehearing and Stay of
Public Interest Organizations

Exhibit 2-40a:
Department's Response to PIOs' RFR of July Resource Adequacy Report

**Department of Energy**
Washington, DC 20585

September 5, 2025

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**RE: August 8, 2025 Submission**

To Whom It May Concern:

Thank you for your August 8, 2025 submission on behalf of the Natural Resources Defense Council, the Ecology Center, the Environmental Defense Fund, the Environmental Law and Policy Center, Public Citizen, Sierra Club, and Vote Solar (collectively, the Public Interest Organizations). The submission was titled "Motion to Intervene and Request for Rehearing of Natural Resources Defense Council, the Ecology Center, Environmental Defense Fund, Environmental Law and Policy Center, Public Citizen, Sierra Club, and Vote Solar" (Submission). It was not filed in any active docket.

On July 7, 2025, the U.S. Department of Energy (DOE) issued the Report on Strengthening U.S. Grid Reliability and Security (Resource Adequacy Report or RAR), fulfilling Section 3(b) of Executive Order 14262. The RAR presents a unified, transparent methodology for assessing the reliability of the bulk power system and identifying regions at elevated risk of resource inadequacy under projected load growth and plant retirement scenarios. DOE developed this approach in coordination with NERC and leading industry experts to provide a consistent, data-driven framework for informing federal reliability interventions, particularly as the grid faces surging demand from AI-driven data centers, reindustrialization, and electrification.

In the Submission, the Public Interest Organizations seek rehearing of the RAR under section 313 of the Federal Power Act (FPA).[1] An application for rehearing under section 313 of the FPA[2] may be filed only by a "person, electric utility, State, municipality, or State commission" that is "aggrieved" by "an order issued by [DOE]."[3] If these prerequisites are not met, there is no basis for rehearing. Here, we note that the RAR is simply a report that details the current condition of the United States electrical grid. It contains no directives, nor does it impose legal duties upon any party, including the Public Interest Organizations. As such, it cannot be considered an "order" by which the Public Interest Organizations are "aggrieved" within the meaning of section 313 of the FPA, as would be required to request rehearing. Accordingly, DOE will take no action on the Submission.

---

[1] Submission at 1.
[2] 16 U.S.C. § 825*l*(a).
[3] *Id.*

Sincerely,

Tina Francone
Director of the Grid Deployment Office, Acting

BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

| | |
|---|---|
| Federal Power Act Section 202(c) | ) |
| Emergency Order: Tri-State | ) |
| Generation and Transmission | ) |
| Association, Platte River Power | ) |
| Authority, Salt River Project, | ) |
| PacifiCorp, and Xcel Energy | ) |

Exhibit to
Motion to Intervene and Request for Rehearing and Stay of
Public Interest Organizations

Exhibit 2-41:
Inst. Pol'y Integrity Report



# Enough Energy

## A Review of DOE's Resource Adequacy Methodology

Jennifer Danis
Christoph Graf, Ph.D.
Matthew Lifson

**July 2025**

Institute *for*
Policy Integrity
NEW YORK UNIVERSITY SCHOOL OF LAW

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The authors thank Dr. Adria Brooks and Rob Gramlich for their valuable feedback.

This report does not purport to present the views, if any, of NYU School of Law.

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# Executive Summary

On April 8, 2025, President Trump issued an Executive Order on Strengthening the Reliability and Security of the United States Electric Grid (the EO) requiring the Department of Energy (DOE) to (1) "identify current and anticipated regions with reserve margins below acceptable thresholds" and (2) "establish . . . a protocol to identify which generation resources within a region are critical to system reliability."[1] DOE responded on July 7, 2025 with its *Resource Adequacy Report: Evaluating the Reliability and Security of the United States Electric Grid* (DOE Study).[2]

This report reviews best practices for analyzing whether a region is resource adequate and for identifying whether a particular resource is critical for resource adequacy. It next analyzes the DOE Study as compared to those best practices. Finally, it examines next steps for U.S. resource adequacy policy following the DOE Study, in light of different entities' respective authorities over the issue.

In Part 1, this report outlines a four-step process for evaluating whether a region is resource adequate and then identifying which resources are critical. Each step involves choices between traditional methods and best practices adapted to the evolving risks posed by the energy transition and the new conditions brought about by climate change.

- *Step 1*: *Set a Resource Adequacy Target*: Planners should define resource adequacy targets using a multi-metric approach that captures not just outage frequency but also magnitude and duration, possibly supplemented by metrics focused on tail risks instead of expected values. Targets should be region-specific and reflect a local cost-benefit analysis that weighs the incremental benefits and costs of achieving reduced outages.
- *Step 2: Conduct Resource Adequacy Modeling:* Rather than focusing narrowly on annual peak load, planners should assess whether a region achieves the target from Step 1 by modeling all 8,760 hours of the year in chronological order using probabilistic techniques that account for uncertainty like the Monte Carlo method. Best practices include incorporating weather-linked dependencies; climate-adjusted inputs; and realistic assumptions about retirements and additions, interregional imports, and storage and demand response dynamics. This modeling more accurately reflects the risks posed by variable generation and energy-limited resources.
- *Step 3: Establish Accreditation Values:* Resource accreditations—the specific contribution of a resource or resource type to resource adequacy—should be derived from Step 2's probabilistic modeling of a resource's ability to contribute during hours of highest risk.

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1 Exec. Order No. 14,262, Strengthening the Reliability and Security of the United States Electric Grid, 90 Fed. Reg. 15521, 15521–22 (Apr. 14, 2025).

2 U.S. Dep't of Energy, Resource Adequacy Report: Evaluating the Reliability and Security of the United States Electric Grid (2025), https://perma.cc/A587-S88S.

Effective Load Carrying Capability or related probabilistic methods should be applied to all resource types, including thermal plants, to accurately describe their contributions under a wide range of possible futures and hard-to-predict risk periods. Accreditation methods should be applied equally to thermal and variable resources to allow for technology-neutral comparisons.

- *Step 4: Calculate the Reference Margin Level and the Reserve Margin:* Using the resource adequacy modeling and accreditation values from Steps 2 and 3, planners should calculate a reference margin level—the amount of accredited capacity that corresponds to achieving the resource adequacy target. Comparing a region's actual resource fleet to this benchmark allows planners to determine whether the exit or entry of specific resources would affect achievement of the reference margin level and thus the resource adequacy target, given the resources' accreditations.

Part 2 compares the best practices from Part 1 to DOE's methodology in the DOE Study—in which DOE concluded that all transmission planning regions except ERCOT are currently resource adequate but that all regions except ISO-NE and NYISO will be resource inadequate in 2030. Across multiple dimensions, DOE's approach departs from best practices in ways that call these results into question.

- *Resource Adequacy Targets:* DOE's use of a multi-metric standard—2.4 hours of lost load per year and 0.002% normalized unserved energy—is consistent with best practices, but the choice of values is not. Neither value is appropriately justified based on a cost-benefit framework, and the use of a one-size-fits-all target for the entire country ignores regional differences. Additionally, DOE inappropriately attempts to label PJM as currently resource inadequate even though the region achieves DOE's own target according to DOE's modeling.

- *Resource Adequacy Modeling:* DOE models all 8,760 hours of the year chronologically but relies on a deterministic rather than probabilistic framework, limiting its ability to assess uncertainty or tail risks. This less accurate approach evaluates adequacy only under a fixed set of historical weather and load years. Further, DOE's truncated description of how its model decides whether an outage has been triggered makes this assumption impossible to fully evaluate, but DOE's limited explanation does suggest that it may have adopted an overly conservative approach that exaggerates resource adequacy risk. Finally, DOE's 2030 results are significantly shaped by unrealistic assumptions about additions, retirements, load, and possibly interregional imports.

- *Accreditation and Reference Margin Levels:* The DOE Study does not attempt to identify resources that are critical for any region's resource adequacy, and thus does not calculate accreditation values or reference margin levels. But DOE does estimate the amount of perfect capacity required to bring certain regions to the 0.002% NUSE target. DOE could build upon this approach in the future to calculate reference margin levels, but any future efforts should attend to all prongs of its multi-metric resource adequacy target. Additionally, DOE's perfect capacity additions inexplicably bring regions far beyond 0.002% NUSE, meaning that DOE overstates how difficult it would be to cure the purported resource adequacy shortfalls.

Part 3 answers what should happen next for U.S. resource adequacy policy now that DOE has published its study.

- Given how DOE's statutory authority under Section 202(c) of the Federal Power Act is limited to emergencies, DOE's own conclusion that most regions are not currently experiencing resource adequacy shortfalls suggests that DOE has limited legal authority to address potential problems in 2030. Moreover, the limitations of the DOE Study call into question the accuracy of DOE's forecasts.
- Instead of DOE, the Federal Energy Regulatory Commission and the North American Electric Reliability Corporation could more appropriately—and less intrusively from the perspective of states, grid operators, and markets—support resource adequacy by issuing reliability standards that require best practices for regions' resource adequacy efforts. Rather than establishing a national resource adequacy target, these standards would govern how regions select resource adequacy targets, evaluate if they are achieving them, and measure the contributions of specific resources. This step would be in line with the Federal Energy Regulatory Commission's Order No. 747, which approved analytical guardrails for resource adequacy analysis for a portion of the U.S.

# Introduction

How does a regional electric grid operator know when its region has enough electricity to meet demand and whether any specific generation resource, like a particular coal plant, is essential for doing so? President Trump's Executive Order on Strengthening the Reliability and Security of the United States Electric Grid (the EO) implicates these questions: The EO directs the Department of Energy (DOE) to assess if each region of the United States has sufficient energy resources to meet current and future demand, and to identify and retain critical resources.[3] On July 7, 2025, DOE responded to the EO by publishing its *Resource Adequacy Report: Evaluating the Reliability and Security of the United States Electric Grid* (DOE Study).[4]

This report addresses the EO and the DOE Study's fundamental concern: resource adequacy. Resource adequacy is one key aspect of a power system's reliability. It refers to a system's "ability . . . to generate and transmit adequate quantities of electricity to meet demand, taking into account scheduled and reasonably expected unscheduled system outages."[5] Resource adequacy thus concerns whether a system's supply of energy exceeds demand. Determining whether an area is resource adequate is, however, ultimately a policy question, rather than an engineering one, because it would be prohibitively expensive to build a system that serves 100% of demand under all conditions.[6] Deciding whether a region is resource adequate always explicitly or implicitly balances society's desire for reliable electricity with the cost of providing that reliability.

Starting from first principles, Part 1 examines how to determine whether a region meets its selected resource adequacy target and how a planner can know whether any one particular resource is critical for resource adequacy. Part 2 discusses whether the DOE Study reflects, rejects, or obscure these first principles. Part 3 explores next steps for U.S. resource adequacy policy following the publication of the DOE Study, considering the respective roles of the Federal Energy Regulatory Commission (FERC), the North American Electric Reliability Corporation (NERC), DOE, grid operators, and states.

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3 Exec. Order No. 14,262, Strengthening the Reliability and Security of the United States Electric Grid, 90 Fed. Reg. 15521, 15521 (Apr. 14, 2025).

4 U.S. Dep't of Energy, Resource Adequacy Report, *supra* note 2.

5 Burçin Ünel & Avi Zevin, Inst. for Pol'y Integrity, Toward Resilience: Defining, Measuring, and Monetizing Resilience in the Electricity System 11 (2018), https://perma.cc/UDB5-DEEM (citing a NERC "Frequently Asked Questions" page that is no longer available).

6 Energy Sys. Integration Grp., New Resource Adequacy Criteria for the Energy Transition: Modernizing Reliability Requirements 38 (2024), https://perma.cc/NXU4-N4UG.

# Part 1: Best Practices for Resource Adequacy

The EO requires DOE to evaluate the sufficiency of regions' "reserve margins" and establish a resulting protocol to identify "critical" resources that should be retained.[7] To figure out what kind of buffer will ensure that a region achieves a given level of resource adequacy, and to label specific generators as essential for that resource adequacy, a planner would need to undertake a four-step process. At each step, the planner must pick between antiquated approaches and newer best practices.

First, the planner must make the policy choice of selecting a resource adequacy target for the region that, if achieved, would indicate resource adequacy. Second, it should use resource adequacy modeling to determine whether a region has achieved and will continue to achieve the selected target under foreseeable future conditions. Third, the planner should use its resource adequacy modeling with accurate data curation to derive how each generation and storage resource contributes to meeting the target (their "accreditation" values). Fourth, it should use the resource adequacy modeling plus resources' accreditation values to derive an acceptable reserve margin for the region (the "reference margin level"). At this fourth step, the planner can use the accreditation values to check whether the exit of a particular resource would cause a region to dip below the reference margin level.

These best practices have largely emerged to address the resource adequacy challenges caused by the energy transition and extreme weather events caused by climate change. Whereas traditional methods have focused on whether demand would exceed supply during peak load hours, system risk has shifted to *net* peak hours, i.e., when load minus variable generation is highest.[8] Measuring whether supply will meet demand has itself become more complicated. Increasingly, it has become important to perform modeling resource adequacy chronologically—each hour reflecting the conditions that came before it—to account for the dynamics of battery storage resources and demand response.[9] And policymakers now are also confronting the outdated idea that thermal resources are "perfect" capacity, given their weather-related vulnerabilities.[10]

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7 Exec. Order No. 14,262, Strengthening the Reliability and Security of the United States Electric Grid, 90 Fed. Reg. 15521, 15521–22 (Apr. 14, 2025).

8 Juan Pablo Carvallo et al., Lawrence Berkeley Nat'l Lab'y, A Guide for Improved Resource Adequacy Assessments in Evolving Power Systems: Institutional and Technical Dimensions 13 (2023), https://perma.cc/5VLY-B7HF.

9 N. Am. Elec. Reliability Corp. & Nat'l Acad. of Eng'g, Evolving Planning Criteria for a Sustainable Power Grid: A Workshop Report 9 (2024), https://perma.cc/KE8D-W6VX.

10 Nat'l Ass'n of Regul. Util. Comm'rs, Resource Adequacy for State Utility Regulators: Current Practices and Emerging Reforms 32–34 (Nov. 2023), https://perma.cc/K88X-2JCR.

## Step 1: Pick a Resource Adequacy Target

Before any analysis can determine if a system is resource adequate, policymakers must set a clear resource adequacy *target*.[11] This first step involves two distinct choices: (1) selecting one or more metrics to represent the variables by which resource adequacy will be judged, and (2) setting the numerical values for those chosen metrics to achieve the resource adequacy target.

Consider what it would take to set a target, not for resource adequacy, but for human health. First, you would pick the metrics that you think would best define whether a person is healthy, e.g., blood pressure, resting heart rate, or cholesterol levels. Using only one metric would not give you enough information. And paying attention to only each metric's average levels without also examining whether the metric ever reaches dangerous levels could obscure risk of a catastrophic health event. Second, you would pick a value for each metric, like a blood pressure of less than less than 120/80 mmHg. To pick that value, you would consider the best available evidence on what level is optimal.

Similarly, when it comes to resource adequacy, the best practice is to move beyond the standard approach of attending primarily to the *frequency* of outages and to also consider their *magnitude* and *duration*. Additionally, regions should consider metrics focused on the extremes of the probability distribution, rather than expected value metrics that could label a system as resource adequate when a low probability (but plausible) event would be catastrophic.

When selecting numerical values for the chosen resource adequacy metrics, the best practice is to consider the best available evidence on the tradeoff between the benefits and costs of additional resource adequacy. The optimal level of resource adequacy may be different in each region, depending on the local costs of the investments that would be needed to reduce shortfall events and the local consequences of a shortfall.[12] A resource adequacy target should ideally represent the level of resource adequacy that the system planner has identified as socially optimal because it balances costs and benefits.

### Metrics

Historically, U.S. policymakers have framed their resource adequacy targets in terms of loss of load expectation (LOLE),[13] and this metric remains widespread.[14] LOLE typically refers to the number of days per year in which an outage occurs and is largely a measure of frequency.[15]

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11 *See* Energy Sys. Integration Grp., New Resource Adequacy Criteria, *supra* note 6, at 2 tbl.1.

12 *Id.* at 39, 41.

13 Elec. Power Rsch. Inst., Metrics and Criteria: Insights from Case Studies and Recommendations and Considerations for Future Practice 31 (2024), https://perma.cc/W4VF-VQPD.

14 Energy Sys. Integration Grp., New Resource Adequacy Criteria, *supra* note 6, at 8 tbl.2.

15 Elec. Power Rsch. Inst., Resource Adequacy for a Decarbonized Future 3, 8 (Apr. 2022), https://perma.cc/7G9V-CNWB. Technically, the number of days per year in which an outage occurs is "loss of load days" (LOLD), which is a special case of the broader concept of LOLE, which can be used with different event-periods. *Id.* at 7–8. In North America, however, LOLE typically means LOLD. *Id.* at 7; *accord* Gord Stephen et al., *Clarifying the Interpretation and Use of the LOLE Resource Adequacy Metric* at 2, https://perma.cc/A9DJ-C3B5.

Frequency is an important characteristic to track because consumers prefer fewer outages.[16] LOLE coarsely accounts for duration, too, in that an outage that stretches multiple days will count as an additional event for each additional day.

LOLE does, however, obscure important aspects of resource adequacy. It will not differentiate between (1) a 10-hour event with 1 GWh of load shed that is followed by a second identical event within the same day and (2) a 30-minute event with 5 MWh of load shed. Customers are not indifferent, however, between these two situations.[17] Because damages depend on outages' frequency, magnitude, and duration, LOLE neglects key dimensions of resource adequacy affecting customers' wellbeing.[18] Attending to these characteristics when setting resource adequacy targets is more important than ever, because changes in the resource mix and extreme weather due to climate change mean that loss-of-load events have become less uniform and thus less interchangeable.[19]

### *The Multi-Metric Approach*

The best practice is to supplement the traditional LOLE metric (or a different frequency-focused metric like "loss of load events," which separately counts all events within a year and thus differentiates between events that occur during the same day[20]) with additional metrics that capture other dimensions of resource adequacy.[21] Both the Electric Reliability Council of Texas (ERCOT) and the Northwest Power and Conservation Council (NWPCC) have done exactly this, augmenting their LOLE-based targets to include magnitude and duration metrics.[22] Under a multi-metric approach, a system could be declared resource adequate if it achieves selected value targets for each and every metric,[23] or if it achieves some minimum number or combination of the metrics (e.g., any two of a system's three metrics).[24]

A leading magnitude metric that could be incorporated into a multi-metric approach is expected unserved energy (EUE): the amount of demand that the system will fail to serve during a period, typically a year.[25] A region's EUE can be contextualized by dividing it by the region's total annual load—this is called normalized unserved energy (NEUE).[26] Australia uses an annual unserved

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16 Energy Sys. Integration Grp., New Resource Adequacy Criteria, *supra* note 6, at 17.

17 *Id.* at 3.

18 *Id.* at 10.

19 *Id.* at 11, 15, 22.

20 Elec. Power Rsch. Inst., Resource Adequacy for a Decarbonized Future, *supra* note 15, at 8.

21 Energy Sys. Integration Grp., New Resource Adequacy Criteria, *supra* note 6, at 33–37; Elec. Power Rsch. Inst., Resource Adequacy Philosophy: A Guide to Resource Adequacy Concepts and Approaches 23 (2022), https://perma.cc/ZH4Y-ZD7J; Juan Pablo Carvallo et al., *supra* note 8, at 28–29; N. Am. Elec. Reliability Corp. & Nat'l Acad. of Eng'g, *supra* note 9, at vii.

22 Reliability Standard for the ERCOT Region, No. 54584, 2024 WL 4263493, at *24 (Tex. Pub. Utils. Comm'n Sept. 9, 2024); *Resource Adequacy*, Nw. Power & Conservation Council, https://perma.cc/39P6-VBNN.

23 Energy Sys. Integration Grp., New Resource Adequacy Criteria, *supra* note 6, at 35.

24 Elec. Power Rsch. Inst., Metrics and Criteria, *supra* note 13, at 31–32.

25 Energy Sys. Integration Grp., New Resource Adequacy Criteria, *supra* note 6, at 17.

26 *Id.* at 18.

energy metric,[27] as does NWPCC.[28] Planning around these magnitude metrics can help a region avoid catastrophic events associated with significant unserved energy.[29]

But, like LOLE, magnitude-focused metrics like EUE and NEUE are incomplete alone; they do not account for how the unserved energy is distributed throughout the year.[30] An alternative or complementary magnitude metric is "peak shortfall," defined as the largest expected outage of the period.[31] Peak shortfall is potentially useful because damages from a single outage increase nonlinearly with its scale.[32] Both ERCOT and NWPCC have versions of a peak shortfall metric (NWPCC's complements its EUE metric).[33]

For duration, a popular metric that could supplement frequency and magnitude metrics is loss of load hours (LOLH), which measures the number of hours per year in which an outage occurs.[34] LOLH fundamentally resembles LOLE, but is more granular because it analyzes each hour, rather than each day. As such, LOLH does a better job at expressing the aggregate duration of all shortfalls in a region.[35]

Many countries use LOLH as their sole resource adequacy metric,[36] but, in aggregating hours, it neglects the duration of individual events—even though damages increase nonlinearly with an outage's duration.[37] Supplemental metrics such as average shortfall duration[38] and the maximum shortfall length (used in Texas and NWPCC)[39] can capture this aspect of duration.

### *Accounting for Tail Risks*

Beyond questions of frequency, magnitude, and duration, a separate question when using any chosen metric is whether to look at the mean of the distribution, extremes, or both. Traditionally, regions have framed their LOLE, EUE, and LOLH goals in terms of their *mean* values.[40] But the energy transition and climate change have increased the risk of extremely damaging tail risks,[41]

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27 *Id.* at 9.

28 Nw. Power & Conservation Council, *supra* note 22.

29 Energy Sys. Integration Grp., New Resource Adequacy Criteria, *supra* note 6, at 19 tbl.4.

30 *Id.*

31 Elec. Power Rsch. Inst., Resource Adequacy Assessment Tool Guide 18 (2024), https://perma.cc/CB7Q-MXZM (using the equivalent phrase "MW Short").

32 Energy Sys. Integration Grp., New Resource Adequacy Criteria, *supra* note 6, at 3.

33 Reliability Standard for the ERCOT Region, No. 54584, 2024 WL 4263493, at *24 (Tex. Pub. Utils. Comm'n Sept. 9, 2024); *Resource Adequacy*, Nw. Power & Conservation Council, https://perma.cc/39P6-VBNN.

34 Elec. Power Rsch. Inst., Resource Adequacy for a Decarbonized Future, *supra* note 15, at 8.

35 *Id.* at 8.

36 Energy Sys. Integration Grp., New Resource Adequacy Criteria, *supra* note 6, at 8.

37 *Id.* at 3.

38 Elec. Power Rsch. Inst., Resource Adequacy for a Decarbonized Future, *supra* note 15, at 10.

39 Reliability Standard for the ERCOT Region, No. 54584, 2024 WL 4263493, at *24 (Tex. Pub. Utils. Comm'n Sept. 9, 2024); *Resource Adequacy*, Nw. Power & Conservation Council, https://perma.cc/39P6-VBNN.

40 Elec. Power Rsch. Inst., Resource Adequacy Gap Assessment 4 (2023), https://perma.cc/M3A5-2WAL; Juan Pablo Carvallo et al., *supra* note 8, at 12.

41 Energy Sys. Integration Grp., New Resource Adequacy Criteria, *supra* note 6, at 22.

making it increasingly appropriate to factor these risks into regions' metrics.[42] When it comes to resource adequacy, customers care not just about how the how severe and common outages will be on average, but also about how bad the worst outages they will experience could be.

One option for assessing these potentially severe consequences is the "value at risk" method. This method defines the selected metric (whether it is focused on frequency, magnitude, or duration), not in terms of its expected value, but in terms of how bad some relatively unlikely but still plausible scenario would be.[43] For example, one of NWPCC's metrics is the maximum shortfall length, framed in terms of what the maximum shortfall length will be at the 97.5$^{th}$ percentile of the distribution, i.e., how long the shortfall would be if there were only a 2.5% chance that the shortfall could be longer.[44] Planners can also frame a metric both in terms of expected value *and* value at risk for the same system: Belgium previously had an LOLE metric that simultaneously required an expected value of less than 3 LOLH and required the 95$^{th}$ percentile of the distribution to be less than 20 LOLH.[45]

An alternative to the value at risk method is the "conditional value at risk" method, in which the metric is framed not in terms of the value at some percentile of the distribution, but in terms of the average value of the distribution beyond the percentile.[46] Policymakers' preference between these two options will depend on their risk tolerance, as the value at risk method will equally weight all tail events while the conditional value at risk method effectively places more weight on extreme events even within the tail.[47]

### Values

After picking resource adequacy metrics—whether singular or multi-valued, and based on expected values, tail risks, or a combination of the two—the second step for setting a resource adequacy target is picking the numerical value for the metric(s). In the U.S., the most common value for the LOLE metric is 0.1, i.e., outages should occur no more than 0.1 days per year.[48] Selecting a value inherently involves balancing customers' desire for resource adequacy with the cost of achieving it.[49]

Notwithstanding that tradeoff, U.S. resource adequacy planners have largely set these values without any economic analysis. The origin of the widespread 0.1 LOLE target is somewhat enigmatic, especially relative to its contemporary significance, but it appears to describe the

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42 *See* Juan Pablo Carvallo et al., *supra* note 8, at 29; Elec. Power Rsch. Inst., Resource Adequacy Gap Assessment, *supra* note 40, at 8; Elec. Power Rsch. Inst., Resource Adequacy for a Decarbonized Future, *supra* note 15, at 10; Energy Sys. Integration Grp., New Resource Adequacy Criteria, *supra* note 6, at 26–27.

43 Energy Sys. Integration Grp., New Resource Adequacy Criteria, *supra* note 6, at 26–27.

44 Nw. Power & Conservation Council, Pacific Northwest Power Supply Adequacy Assessment for 2029 12 (2024), https://perma.cc/GZY2-PKY7.

45 Elec. Power Rsch. Inst., Metrics and Criteria, *supra* note 13, at 17.

46 Energy Sys. Integration Grp., New Resource Adequacy Criteria, *supra* note 6, at 26–27; Elec. Power Rsch. Inst., Resource Adequacy for a Decarbonized Future, *supra* note 15, at 10.

47 Energy Sys. Integration Grp., New Resource Adequacy Criteria, *supra* note 6, at 27 fig.8.

48 *Id.* at 8.

49 *Id.* at 38.

level of resource adequacy that happened to exist in the 1940s.[50]

The values used in NERC's reports on regions' long-term resource adequacy similarly seem arbitrary. NERC uses a LOLH metric, labeling regions with greater than 2.4 LOLH as high risk, 0.1-2.4 as elevated risk, and less than 0.1 as normal risk. NERC does not explain the basis for these categories, but they appear to stem this from a common (but widely criticized) hourly conversion of the 0.1 LOLE standard.[51] And NERC's values for the NEUE metric—above 0.002% is high risk, less than 0.002% but above zero is elevated risk, negligible or zero is normal risk—is adapted from Australia's 0.002% NEUE target without considering the different national contexts.[52] Context matters because the U.S. and Australia may vary in terms of how damaging outages would be (e.g., how bad it would be to lose electric heating and cooling in light of the region's temperatures) and how expensive it would be to avert them (e.g., the country-specific cost of building a natural gas peaker plant).

A better practice would be to use economic principles to select a socially efficient resource adequacy target, i.e., to select the value at which the incremental costs of additional resource adequacy equal the incremental benefits of achieving it.[53] Where policymakers do estimate the *costs* of improving resource adequacy, they often turn to the concept of "cost of new entry" (CONE).[54] CONE, expressed in $/MWh, represents the marginal investment and fixed costs of adding additional capacity to the system to achieve a more stringent resource adequacy standard.[55] Historically, planners assumed the marginal resource was a combustion turbine, but today it is more accurate to assume a portfolio of diverse resources.[56] Considering CONE by itself, however, does not accurately capture the social marginal cost of achieving higher levels of resource adequacy, because adding capacity can have follow-on effects like reducing the cost of energy.[57] Accordingly, it is better to estimate total net CONE, which nets out potential system benefits such as reduced energy costs for loads and lower operating costs.[58]

To estimate the *benefits* of additional resource adequacy, planners typically rely on the value of lost load (VOLL).[59] The VOLL represents the societal cost of failing to serve a unit of energy

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50 Kevin Carden et al., Nat'l Regul. Rsch. Inst., The Economics of Resource Adequacy: Why Reserve Margins Are Not Just About Keeping the Lights On 2 (2011), https://perma.cc/LS2F-2EZR; Energy Sys. Integration Grp., New Resource Adequacy Criteria, *supra* note 6, at 6.

51 *See* N. Am. Elec. Reliability Corp., 2024 Long-Term Reliability Assessment 11–12 (2024), https://perma.cc/GJB2-VCZQ; Juan Pablo Carvallo et al., *supra* note 8, at 11 ("The LOLE is typically used as a target setting metric and has historically taken a value of 1 event-day in 10 years, commonly (and incorrectly) interpreted as 2.4 hours per year.").

52 N. Am. Elec. Reliability Corp., 2024 Long-Term Reliability Assessment, *supra* note 51, at 141.

53 Kevin Carden et al., *supra* note 50, at 1; Energy Sys. Integration Grp., New Resource Adequacy Criteria, *supra* note 6, at 38–42; Elec. Power Rsch. Inst., Metrics and Criteria, *supra* note 13, at 35.

54 Energy Sys. Integration Grp., New Resource Adequacy Criteria, *supra* note 6, at 13, 41–42.

55 *Id.* at 42.

56 *Id.*

57 Christoph Graf et al., *Cost-Effective Capacity Markets* 29, https://papers.ssrn.com/sol3/papers.cfm?abstract_id=4864513 (posted June 21, 2024); Kevin Carden et al., *supra* note 50, at 8–9.

58 Energy Sys. Integration Grp., New Resource Adequacy Criteria, *supra* note 6, at 42.

59 Elec. Power Rsch. Inst., Metrics and Criteria, *supra* note 13, at 35.

demanded by consumers and is denominated in $/MWh.[60] Estimates vary significantly across customer classes,[61] but modelers can capture this through averaging.[62] More challenging is capturing how the VOLL varies with an outage's particular characteristics. For relatively short outages, the first hour tends to the most expensive,[63] indicating that many frequent outages could be more socially disruptive than a consolidated one of equal length. Long-duration outages result in damages that increase nonlinearly (food spoilage, jeopardized medical care, and loss of access to safe drinking water).[64] Similarly, the VOLL can increase nonlinearly with magnitude: When the grid operator can no longer manage the situation through rotating outages, the resulting uncontrolled outage is much more damaging.[65] Accordingly, undertaking a cost-benefit analysis that allows VOLL to vary with duration and magnitude would produce a more accurate, cost-benefit-justified resource adequacy target.

Many jurisdictions use some version a cost-benefit analysis when setting their resource adequacy targets. In the European Union, countries solve for their specific LOLH targets by dividing a local CONE value by the local VOLL, which, in 2023, resulted in a range from 1 LOLH (Sweden) to 15 LOLH (Czechia).[66] The United Kingdom uses this same approach.[67] Australia periodically reviews its 0.002% NEUE target to ensure that the implied "value of customer reliability," which is akin the VOLL, is close to its estimated value.[68] Somewhat analogous to these examples, the administratively set, downward-sloping demand curves for capacity markets in U.S. regions like PJM embody the tradeoff between the benefits and costs of additional resource adequacy, because the curves dictate how much regions are willing to pay for each increment of additional capacity given the capacity's incremental benefits.[69] Technically, though, this cost-benefit thinking happens not when *setting* the resource adequacy target, but in deciding whether to under-, over-, or exactly *achieve* an already-determined target.

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60 Jennifer Danis et al., Inst. for Pol'y Integrity, Transmission Planning for the Energy Transition: Rethinking Modeling Approaches 6 (2023), https://perma.cc/5A6L-DJHL.

61 Michael J. Sullivan et al., Ernest Orlando Lawrence Berkeley Nat'l Lab'y, Updated Value of Service Reliability Estimates for Electric Utility Customers in the United States xii, tbl.ES-1 (2015), https://perma.cc/CT53-8WEA.

62 *See* Elec. Power Rsch. Inst., Metrics and Criteria, *supra* note 13, at 35.

63 Michael J. Sullivan et al., *supra* note 61, at xii, tbl.ES-1.

64 Energy Sys. Integration Grp., New Resource Adequacy Criteria, *supra* note 6, at 23 fig.5.

65 *See, e.g.*, Joshua W. Busby et al., *Cascading Risks: Understanding the 2021 Winter Blackout in Texas*, 77 Energy Rsch. & Soc. Sci. (2021); Sergio Castellanos et al., *A Synthesis and Review of Exacerbated Inequities from the February 2021 Winter Storm (Uri) in Texas and the Risks Moving Forward*, 5 Progress in Energy (2023); Hassan Haes Alhelou et al., *A Survey on Power System Blackout and Cascading Events: Research Motivations and Challenges*, 12 Energies 1, 16–17 (2019).

66 Energy Sys. Integration Grp., New Resource Adequacy Criteria, *supra* note 6, at 39 fig.12, 40.

67 *Id.* at 40.

68 Reliability Panel AEMC, Final Report: Reliability Standard and Settings Review 2018 i, 14 (2018), https://perma.cc/TAN8-TPXZ.

69 *PJM Interconnection, L.L.C.*, 117 FERC ¶ 61,331, at P 76 (2006) ("In addition, we agree with PJM that a downward-sloping demand curve provides a better indication of the incremental value of capacity at different capacity levels than the current vertical demand curve. Under a vertical demand curve, capacity above the Installed Reserve Margin is deemed to have no value. Incremental capacity above the Installed Reserve Margin is likely to provide additional reliability benefits, albeit at a declining level. This value is reflected in the positive (but declining) prices in the sloped demand curve to the right of the Installed Reserve Margin, but is not reflected in the current capacity market.").

## Step 2: Conduct Resource Adequacy Modeling

Once the policymaker sets a resource adequacy target, a resource adequacy model can predict whether a region is achieving it (and will continue to do so). Traditionally, modeling was limited to examining whether demand would exceed supply during one or a few peak load hours. But the energy transition, combined with extreme weather from climate change, requires planners to rethink prevailing resource adequacy modeling techniques. For most systems, it is now important to model all 8,760 hours of the year, in chronological order, to accurately capture the risk of load shed.

Along with improving models' temporal resolution, it has become important to make more sophisticated assumptions about modeling inputs. In particular, it has become critical to capture how supply and demand have become more dependent on the weather, which, in turn, has become more extreme. In general, a best practice is to use the Monte Carlo method, and run many (on the order of hundreds or thousands) simulations of grid operations, allowing the model to randomly pull from a distribution of possible values for every input.[70] Additionally, best practices exist for curating the data for each input and their interdependencies, such as representing the relationship between the weather and thermal outages.[71]

### Temporal Scope

Historically, resource adequacy modeling focused on the likelihood that supply would exceed demand during one (or a few) top demand hours, ignoring the risk of inadequate supply during the rest of the year.[72] This simplification was more plausible when the grid was dominated by dispatchable resources with relatively predicable outputs.[73]

Now, with the increased penetration of wind and solar, periods of resource adequacy risk have shifted from peak demand to "net peak" demand, defined as load minus energy from non-dispatchable resources.[74] In this new reality, the system is most likely to lack sufficient supply when there is high demand unserved by wind or solar. And, just as weather dictates the performance of these variable resources, it also affects outages at thermal generators (e.g., interruptions of natural gas supply) and load (not just by influencing customers' demand, but also by altering

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70 See Inputs, below, for a more detailed description of the Monte Carlo method.

71 For example, cold winter snaps have historically yielded correlated outages of thermal generators. Nick Wintermantel & Nick Simmons, Astrapé Consulting 8 (2022), https://perma.cc/6D7Y-QCZ2. Similarly, extreme hot weather can require both thermal and nuclear units to cease operations, if the unit can no longer use intake water bodies for cooling. *E.g., High French River Temperatures to Hit Nuclear Production Next Week*, Reuters (June 20, 2025), https://www.reuters.com/business/energy/high-french-river-temperatures-hit-nuclear-production-next-week-2025-06-20.

72 Juan Pablo Carvallo et al., *supra* note 8, at 9; N. Am. Elec. Reliability Corp. & Nat'l Acad. of Eng'g, *supra* note 9, at 2.

73 N. Am. Elec. Reliability Corp. & Nat'l Acad. of Eng'g, *supra* note 9, at 2; Juan Pablo Carvallo et al., *supra* note 8, at 1, 27.

74 Jill Moraski et al., Clean Air Task Force, Beyond LCOE: A Systems-Oriented Perspective for Evaluating Electricity Decarbonization Pathways 21 (2025), https://perma.cc/3A39-FQLW.

behind-the-meter generation that typically provides "negative" load).[75] Given this confluence of variables, the best practice is now to examine all 8,760 hours of the year when evaluating the likelihood and expected characteristics of shortfalls.[76]

The increased prevalence of energy-limited resources like battery storage and demand response have similarly complicated more traditional resource adequacy modeling assumptions. Battery storage's ability to avoid a resource adequacy shortfall will depend on its state of charge.[77] For example, a battery could have sufficient energy to prevent a shortfall in the morning and then, if it has no opportunity to recharge, be empty for a second event that same afternoon. Similarly, demand response participants have only a limited willingness to curtail or shift their demand; activating the program degrades its later effectiveness.[78] Accordingly, the best practice for resource adequacy modeling is to not just to consider all 8,760 hours, but to do so sequentially, capturing how storage and demand response used in one hour can affect their subsequent availability.[79]

## Inputs

To keep pace with the many uncertainties of contemporary resource adequacy analysis, planners have shifted to probabilistic modeling approaches like the Monte Carlo method.[80] Under this best practice, rather than assessing resource adequacy using specific expected values for each input, the user provides the model with a probability distribution for different inputs, and the model randomly samples from those distributions across hundreds or thousands of simulated scenarios.[81] The model will draw the load for each hour, along with potentially correlated variable generation, thermal resource availability, and transmission outages.[82]

While the Monte Carlo method can yield more accurate resource adequacy estimates than simpler methods, its accuracy depends on the user-provided probability distributions, as well as accurate specification of key interdependencies.[83] For weather data, the current best practice is to use as many years as are available, with hourly resolution and geographic granularity.[84] And, especially when forecasting longer-term resource adequacy, it has become important to account

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75 Juan Pablo Carvallo et al., *supra* note 8, at 27; Standard Authorization Request (SAR) Form, N. Am. Elec. Reliability Corp. at 2, https://perma.cc/Q8AU-9YWW.

76 Juan Pablo Carvallo et al., *supra* note 8, at 27; Standard Authorization Request (SAR) Form, N. Am. Elec. Reliability Corp. at 2, https://perma.cc/Q8AU-9YWW.

77 Energy Sys. Integration Grp., Ensuring Efficient Reliability: New Design Principles for Capacity Accreditation 11 (2023), https://perma.cc/4ETD-JQK2.

78 Elec. Power Rsch. Inst., Resource Adequacy Assessment Tool Guide, *supra* note 31, at 55–56.

79 N. Am. Elec. Reliability Corp. & Nat'l Acad. of Eng'g, *supra* note 9, at 9; Juan Pablo Carvallo et al., *supra* note 8, at 9; Nat'l Ass'n of Regul. Util. Comm'rs, *supra* note 12, at 44.

80 Elec. Power Rsch. Inst., Resource Adequacy Assessment Tool Guide, *supra* note 31, at 9.

81 *Id.* at 10.

82 Juan Pablo Carvallo et al., *supra* note 8, at 13.

83 Elec. Power Rsch. Inst., Resource Adequacy Assessment Tool Guide, *supra* note 31, at 12.

84 Juan Pablo Carvallo et al., *supra* note 8, at 30.

for climate change projections,[85] including the increasing severity of extreme events.[86]

For load, the best practice is to capture its relationship to the weather, and to add a probabilistically determined amount of distributed generation as negative load.[87] Similarly, for generation, the best practice is to derive the relationship between weather and its output, while also accounting for how technological improvements will improve production profiles,[88] along with the possibility of other types of common mode failures.[89]

Other important considerations include realistic assumptions about electricity imports from neighboring regions (e.g., probabilistically modeling neighbors' operations during tight periods),[90] intraregional transmission constraints,[91] the impact of probabilistic intraregional transmission failures,[92] and for when the model decides that an outage has been triggered.[93]

Additionally, for forecasting longer-term resource adequacy, modelers need to make assumptions about which resources retire and come online. These assumptions will have a large bearing on model outputs. For retirements, modelers should include announced retirements while also forecasting unannounced retirements by accounting for likely retirements due to federal and state policy, age-based retirements, and retirements driven by economics.[94] For near-term new generation and storage, modelers should consider projects that have cleared or will soon clear the interconnection queue, along with expected build times.[95] To anticipate later-term resource additions, modelers should consider resource costs and trajectories, regulatory incentives and barriers, and other relevant drivers. As with other inputs, modelers can implement retirements and additions through a distribution of probabilities, rather than strict assumptions about what will occur.[96]

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85 *Id.*

86 Elec. Power Rsch. Inst., Resource Adequacy Gap Assessment, *supra* note 40, at 22.

87 Juan Pablo Carvallo et al., *supra* note 8, at 31.

88 *Id.* at 32.

89 Elec. Power Rsch. Inst., Modeling New and Existing Technologies and System Components in Resource Adequacy 17–18 (2023), https://perma.cc/3CWR-G5LM; Energy Sys. Integration Grp., Ensuring Efficient Reliability, *supra* note 77, at 37–38; *How MISO Utilizes PLEXOS for Enhanced Resource Adequacy*, Energy Exemplar (Oct. 9, 2024), https://perma.cc/VQY8-WAVX.

90 Elec. Power Rsch. Inst., Resource Adequacy Gap Assessment, *supra* note 40, at 31; Adria E. Brooks et al., Grid Strategies LLC, Resource Adequacy Value of Interregional Transmission 31 (2025), https://perma.cc/77FQ-L94V; Sam Hostetter & Derek Stenclik, Analysis of Resource Adequacy Across the Eastern Interconnection 7, 16 (2025), https://perma.cc/LCU4-LBZF.

91 Elec. Power Rsch. Inst., Resource Adequacy Scenario Selection Guide 6, (2024), https://perma.cc/FZ5A-5G2M.

92 Juan Pablo Carvallo et al., *supra* note 8, at 13–14; Elec. Power Rsch. Inst., Resource Adequacy Gap Assessment, *supra* note 40, at 12.

93 Kevin Carden et al., *supra* note 50, at 7.

94 Inst. for Pol'y Integrity, Comments on Policy-Driven Retirements in the Context of Order No. 1920 at 4–6 (Oct. 18, 2024), https://perma.cc/GB4R-X55D.

95 *E.g.,* N. Am. Elec. Reliability Corp., 2024 Long-Term Reliability Assessment, *supra* note 51, at 137.

96 *See* Inst. for Pol'y Integrity, Comments, *supra* note 94, at 7–8.

## Step 3: Accreditation

After resource adequacy modeling, the next step is to derive how much credit each resource deserves for its contribution towards the system's resource adequacy—a process called "accreditation." A resource's accreditation, typically expressed as a fraction of its nameplate capacity, captures the resource's estimated availability during the periods when resource adequacy is most strained.[97]

If a planner is interested in determining only whether a system is achieving its resource adequacy target, this step is unnecessary because Step 2 will accomplish that.[98] Nor is this step strictly necessary to determine how the retirement of any particular resource would affect reaching the resource adequacy target; a planner can accomplish that by re-running Step 2 without the resource included.

But, as explained further in Step 4, accreditation is important to calculate a region's *reference reserve margin*, i.e., the resource adequacy cushion that, when obtained, suggests that the system will achieve its resource adequacy target. Accreditation is also valuable because, once a planner calculates the reference margin level, having these accreditation values can allow a policymaker to quickly estimate how the retirement or addition of particular resources would affect maintaining that margin, without needing to re-run the resource adequacy modeling. This kind of analysis could satisfy the EO's call for a protocol to "identify which generation resources within a region are critical to system reliability."[99]

Historically, planners accredited thermal resources at their full nameplate capacity—reflecting an assumption that they could always generate at maximum capacity during the moments of greatest resource adequacy risk—or accredited them based on their nameplate capacity discounted by their average forced outage rate.[100] Variable resources have often been accredited based on their historical performance during peak load hours.[101]

With the energy transition and climate change, however, the best practice is to derive a resource's accreditation from the resource adequacy modeling described in Step 2 using a probabilistic

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97 An Pham et al., Nat'l Renewable Energy Lab'y, Average and Marginal Capacity Credit Values of Renewable Energy and Battery Storage in the United States Power System 5 (2024) (using the equivalent phrase "capacity credit"). These times have become increasingly decoupled with peak load events. Energy Sys. Integration Grp., Ensuring Efficient Reliability, *supra* note 77, at 4.

98 Juan Pablo Carvallo et al., *supra* note 8, at 36 ("Capacity accreditation is not inherent to resource adequacy assessments . . . ."); Energy Sys. Integration Grp., Ensuring Efficient Reliability, *supra* note 77, at vii ("While resource adequacy analysis assesses whether there are enough resources to serve load across the system, capacity accreditation measures the contribution of individual resources toward meeting that goal, both in terms of capacity and energy.").

99 Exec. Order No. 14,262, Strengthening the Reliability and Security of the United States Electric Grid, 90 Fed. Reg. 15521, 15522 (Apr. 14, 2025).

100 Energy Sys. Integration Grp., Ensuring Efficient Reliability, *supra* note 77, at 9, 37; Nat'l Ass'n of Regul. Util. Comm'rs, *supra* note 12, at 5.

101 Juan Pablo Carvallo et al., *supra* note 8, at 36.

method.[102] Probabilistic methods like Effective Load Carrying Capability (ELCC) analyze how slight changes in the modeled resource inputs would affect resource adequacy outcomes.[103] They typically work by adding more of the studied resource to the model, beyond what exists in the base case, and then adding load until the model's base case resource adequacy outcome is restored.[104]

The benefit of probabilistic approaches like ELCC is that, when the modeling inputs from Step 2 are well-curated, the resulting accreditations will more accurately reflect a resource's contribution to resource adequacy during the true risk periods.[105] Additionally, these methods consider a wide range of possible futures, including the possibility of tail events, rather than assuming the future will resemble the past.[106]

The best practice is to apply these ELCC-style methodologies to both variable and thermal resources, storage, and transmission.[107] It is important to treat all resource types equally because capacity accreditation provides a technology-agnostic way of comparing resources' resource adequacy contributions.[108] That purpose is compromised when the resource adequacy value of variable resources is reduced to account for myriad factors affecting their output, without parallel reductions capturing thermal resources' weather dependency and common mode outages.[109] With increased saturation of natural gas resources—which are susceptible to fuel disruptions and extreme weather—it is more important than ever to accurately account for thermal generations' winter risks, especially the risk that a significant amount of thermal capacity will become unavailable at once.[110] Probabilistic methods are ideal for understanding the effect of these risks, including tail risks, in light of the complicated interdependencies of all the factors that dictate the timing of resource adequacy shortfalls.[111]

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102 *Id.* at 36–37; N. Am. Elec. Reliability Corp., Methods to Model and Calculate Capacity Contributions of Variable Generation for Resource Adequacy Planning 24–27 (2011), https://perma.cc/294F-25KU.

103 Elec. Power Rsch. Inst., Resource Adequacy for a Decarbonized Future, *supra* note 15, at 13.

104 *Id.*

105 Energy Sys. Integration Grp., Ensuring Efficient Reliability, *supra* note 77, at 12–14; Elec. Power Rsch. Inst., Resource Adequacy for a Decarbonized Future, *supra* note 15, at 15; Christoph Graf et al., *supra* note 57, at 30. As explained in Step 2 above, these risk periods are becoming harder to predict due to weather's increased influence on supply and demand, and because of increased energy-limited resources in the generation mix.

106 Energy Sys. Integration Grp., Ensuring Efficient Reliability, *supra* note 77, at 14.

107 Juan Pablo Carvallo et al., *supra* note 8, at 37; N. Am. Elec. Reliability Corp., Methods to Model and Calculate Capacity Contributions, *supra* note 102, at 28; Adria E. Brooks et al., *supra* note 90, at 31.

108 Energy Sys. Integration Grp., Ensuring Efficient Reliability, *supra* note 77, at 32, 37.

109 *Id.* at 37–38.

110 Elec. Power Rsch. Inst., Resource Adequacy Gap Assessment, *supra* note 40, at 24; Nat'l Ass'n of Regul. Util. Comm'rs, *supra* note 12, at 40–41; Elec. Power Rsch. Inst., Resource Adequacy Assessment Tool Guide, *supra* note 31, at 30; Elec. Power Rsch. Inst., Resource Adequacy Philosophy, *supra* note 21, at 27.

111 *See* Energy Sys. Integration Grp., Ensuring Efficient Reliability, *supra* note 77, at 11 ("Increasingly, periods of risk are driven by correlation among many components that are often weather-related, including high load, low renewable resource availability, drought, and correlated outages and fuel supply disruptions from the fossil fuel generators."); N. Am. Elec. Reliability Corp., 2024 Long-Term Reliability Assessment, *supra* note 51, at 91 ("If resource performance were to occur at the levels expected during average winter days, the system should be able to serve these high loads. However, resource performance from thermal resources on very cold days, especially natural gas resources, is more likely to be poor. This, coupled with poor performance from solar

## Step 4: Calculating the Reference Margin Level and the Reserve Margin

Using Step 2's resource adequacy modeling and Step 3's accreditations, a planner can assess whether a region's fleet would achieve its appropriate reference margin level.[112] The reference margin level typically expresses the amount of accredited capacity that a region would need to achieve its resource adequacy target. The planner will conduct resource adequacy modeling, adding or subtracting additional capacity or load until the system reaches the resource adequacy target. The reference margin level is the sum of the accredited capacity needed to achieve the target.

Once the planner derives the reference margin level (how much total accredited capacity the system requires), it is also possible to answer whether any particular resource is critical to achieving the margin. To check this, the planner would subtract the accredited capacity of the resource in question from the total accredited capacity of the region, and check whether the difference exceeds the reference margin level.

### Reference Margin Levels

Historically, reference margin levels were—and, in some places, continue to be—resource adequacy targets in themselves (e.g., a target of accredited capacity that is 15% above peak load).[113] But setting a target framed entirely around the summed accredited capacity, even when informed by years of operating experience at different margin levels, yields a target that does not explicitly aim to achieve any particular outcome.[114] As explained in Step 1, targets are more typically expressed in terms of outcomes: the frequency, duration, and/or magnitude of shortfalls.

Yet the idea of a reference margin level has persisted, as planners often convert their outcome-focused targets into the equivalent reference margin levels.[115] For example, a region might have a 0.1 LOLE target and then determine that the 0.1 LOLE target is achieved when the region's installed capacity has an accreditation of at least 15% above peak load.[116] The same type of translation is possible for targets set using other metrics, like EUE or LOLH.[117]

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resources, results in very low total electricity supply and causes loss-of-load events in the ProbA analysis. The winter load-loss events tend to occur during morning and evening demand peaks and coincide with poor thermal performance and poor solar performance.").

112 This is also commonly referred to as a planning reserve margin, connoting that it includes resources that are in reserve and only be dispatched in highly constrained scenarios.

113 Elec. Power Rsch. Inst., Resource Adequacy Philosophy, *supra* note 21, at 24; Energy Sys. Integration Grp., New Resource Adequacy Criteria, *supra* note 6, at 8–9.

114 Elec. Power Rsch. Inst., Resource Adequacy for a Decarbonized Future, *supra* note 15, at 5–6; N. Am. Elec. Reliability Corp., Methods to Model and Calculate Capacity Contributions, *supra* note 102, at 29–30.

115 Energy Sys. Integration Grp., New Resource Adequacy Criteria, *supra* note 6, at 7; Juan Pablo Carvallo et al., *supra* note 8, at 37; N. Am. Elec. Reliability Corp. & Nat'l Acad. of Eng'g, *supra* note 9, at 1.

116 Juan Pablo Carvallo et al., *supra* note 8, at 28.

117 N. Am. Elec. Reliability Corp. & Nat'l Acad. of Eng'g, *supra* note 9, at 15; Juan Pablo Carvallo et al., *supra* note 8, at 29.

Given how resource adequacy risk has evolved, however, the best practice is to derive the reference margin level using the probabilistic resource adequacy modeling from Step 2 (itself conducted in accordance with best practices).[118] Doing this helps to ensure that the margin is calculated to comprehensively reflect year-round risks. Indeed, when resource adequacy risk shifts beyond peak load hours, the amount of accredited capacity necessary to achieve the resource adequacy target can become *lower* than peak load—because resources' accreditations will be based on their outputs during moments of greatest risk, which may be lower than their outputs at peak load.[119] Accordingly, calculating a reference margin level that matches accredited capacity to peak load would overestimate the necessary margin.

While there are multiple plausible ways to use probabilistic resource adequacy modeling to convert the resource adequacy target to a reference margin level, the general approach depends on whether the modeling reveals that the system is exactly achieving the target, underachieving it, or overachieving it. For the rare case in which the system happens to be exactly achieving the resource adequacy target, then the sum of the total accredited capacity installed on the system equals the reference margin level. It can be expressed as MW of accredited capacity, or in reference to some other amount, like a percentage of peak load.[120]

It is more likely, however, that the system is either above or below the resource adequacy target. In these instances, it is common to add or subtract accredited capacity in the model until the system achieves the target.[121] Then, the reference margin level will be the amount of accredited capacity on the modeled system when the target is achieved, again expressed as a quantity of MWs or as a percentage of peak load.

### Effect of Particular Resources

Once the reference margin level and accreditation values have been calculated, it becomes possible to test how the exit (or entry) of a particular resource would affect the region's resource adequacy.

An example is useful in understanding how. Imagine that the reference margin level for a region is 25 GW, and its resource mix has 26 GW of accredited capacity. As is, the region would be exceeding its reference margin level by 1 GW. If any resource with an accreditation greater than 1 GW were to exit the grid, that would cause the actual reserve margin to dip below the reference margin level. Because the reference margin level was calculated following Steps 1–3,

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118 Elec. Power Rsch. Inst., Resource Adequacy for a Decarbonized Future, *supra* note 15, at 6, 11; Nat'l Ass'n of Regul. Util. Comm'rs, *supra* note 12, at 95. *See also* N. Am. Elec. Reliability Corp., 2024 Long-Term Reliability Assessment, *supra* note 51, at 11.

119 Energy Sys. Integration Grp., Ensuring Efficient Reliability, *supra* note 77, at 18.

120 *Id.*; N. Am. Elec. Reliability Corp., Methods to Model and Calculate Capacity Contributions, *supra* note 102, at 6.

121 Nat'l Ass'n of Regul. Util. Comm'rs, *supra* note 12, at 95. *See also, e.g.*, MISO, Planning Year 2025–2026 Loss of Load Expectation Study Report 34–35, https://perma.cc/4VV5-4FHU; Western Power Pool, Western Resource Adequacy Program, 102 Forward Showing Reliability Metrics 14 (2024), https://perma.cc/7A6Q-A96E; NYISO, 2024 Reliability Needs Assessment 44 (2024), https://perma.cc/LD5E-RMV9; IESO, Annual Planning Outlook: Resource Adequacy and Energy Assessments Methodology 19 (2024), https://perma.cc/26N7-QC5J.

this dip would indicate that the region can no longer be expected to achieve the resource adequacy target (e.g., 0.1 LOLE) underlying the 25 GW reference margin level. In contrast, any resource with an accredited capacity of 1 GW or less could retire without causing the system to violate its resource adequacy target.

Importantly, this technique for evaluating individual resources' impact works only for relatively small changes to the system, such as the exit or entry of one or a few plants. When larger changes happen in the region's resource composition, the new mix will itself affect resources' accreditation values, because these values inherently depend on the entire fleet composition.[122] To calculate the resource adequacy effect of major changes to the fleet (e.g., the retirement of half of the coal capacity in a region), it would be necessary to re-run the modeling from Step 2 with different inputs.

Having reviewed resource adequacy terms, methodologies, and best practices, Part 2 next uses this understanding to discuss DOE's recent resource adequacy modeling endeavor.

[122] Energy Sys. Integration Grp., Ensuring Efficient Reliability, *supra* note 77, at 30.

# Part 2: DOE's *Resource Adequacy Report*

On July 7, 2025, DOE published its *Resource Adequacy Report: Evaluating the Reliability and Security of the United States Electric Grid* (DOE Study), responding to the EO's request for a "uniform methodology to identify at-risk region(s) and guide reliability interventions."[123] The report does not fulfill the EO's separate request for a "a protocol to identify which generation resources within a region are critical to system reliability."[124]

The DOE Study generally examines the resource adequacy of two time periods: today and 2030. According to the study, today, only ERCOT currently fails to achieve DOE's selected resource adequacy targets.[125] Under DOE's assumptions about load growth (including load growth from data centers), resource additions, and retirements, its modeling shows that all transmission planning regions will be resource inadequate in 2030 except ISO-NE and NYISO.[126] When reporting that a region is or would be resource inadequate, DOE sometimes calculates the amount of perfect capacity that could restore the region to resource adequacy.[127]

The DOE Study borrows heavily from NERC's recent Interregional Transfer Capability Study, which analyzed interregional transmission capacity and evaluated how additional interregional capacity could improve resource adequacy.[128] In contrast to NERC's Interregional Transfer Capability Study, the DOE Study does not consider how shortfalls could be mitigated through additional interregional transmission, which can be an alternative to new generation.[129]

Building on Part 1's discussion of how a resource adequacy model's metrics, values, and input assumptions drive its results, this Part evaluates DOE's resource adequacy methodology, including its input choices for load growth, resource additions, and retirements. At each step, it discusses the assumptions embedded in DOE's modeling choices, and reviews why those assumptions provide a weak basis for commanding specific, aging resources to continue serving load at consumers' expense and outside of existing market structures.

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123 U.S. Dep't of Energy, Resource Adequacy Report, *supra* note 2, at vi.

124 Exec. Order No. 14,262, Strengthening the Reliability and Security of the United States Electric Grid, 90 Fed. Reg. 15521, 15521 (Apr. 14, 2025).

125 U.S. Dep't of Energy, Resource Adequacy Report, *supra* note 2, at 7.

126 *Id.* at 8.

127 *Id.* at 5. The exact meaning of these perfect capacity quantities is unclear due to contradictions within the DOE Study. At times, DOE explains that these are the perfect capacity quantities that restore the system to 0.002% while assuming projected retirements. *Id.* At other points, though, DOE states that these quantities assume no retirements. *Id.* at 9.

128 *Id.* at 2; N. Am. Elec. Reliability Corp., Interregional Transfer Capability Study vi, ix (2024), https://perma.cc/U7M3-L56J.

129 *See generally* Adria E. Brooks et al., *supra* note 90.

## Resource Adequacy Targets

The DOE Study uses a multi-metric resource adequacy target of 2.4 LOLH and 0.002% normalized unserved energy (NUSE), which is the deterministic equivalent to NEUE.[130] DOE's decision to use a multi-metric target aligns with best practices, and its decision to use LOLH and NEUE together is reasonable. But DOE's value selections for these metrics are problematic.

For LOLH, DOE indicated that it picked 2.4 because that value "translates into one day of lost load in ten years," i.e., the traditional 0.1 LOLE standard.[131] This decision does not align with best practices for two reasons. First, it seeks to unquestioningly replicate the already arbitrary 0.1 LOLE standard (which merely captures the level of resource adequacy that happened to exist in the 1940s).[132] DOE's choice thus does not reflect any meaningful cost-benefit analysis.

Second, DOE's conversion of 0.1 LOLE to 2.4 LOLH is inaccurate.[133] A region with 0.1 LOLE will experience only one day with an outage—of any length—across ten years, which will be 24 hours in only the most extreme case. A region with 2.4 LOLH will have 24 hours of outages across the decade, across any combination of hours. DOE's selection of 2.4 LOLH metric would therefore, in the vast majority of cases, permit a greater duration and frequency of outages.[134] Although this 2.4 LOLH target might indicate that, all else being equal, DOE's methodology is too permissive, DOE's inputs and assumptions likely dominate its analysis and lead DOE to overestimate potential shortfalls.

Turning to NUSE, DOE reports that it selected 0.002% because NERC uses that same value in its long-term resource adequacy assessments.[135] But, as discussed in Part 2, NERC adopted that value from Australia without any consideration of how the costs and benefits of resource adequacy differ in the U.S. context.[136] In contrast, DOE previously used 0.001% in the National Transmission Planning Study.[137]

Moreover, contrary to best practices, for both LOLH and NUSE, DOE imposes the same resource adequacy target across the entire continental United States, without considering regional differences. As noted in Part 1, when it comes to averting outages, regions face different costs and benefits with regard to resource adequacy and thus different socially optimal levels of resource adequacy.

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130 U.S. Dep't of Energy, Resource Adequacy Report, *supra* note 2, at 4, 14 ("This study does not employ common probabilistic industry metrics such as EUE or LOLE due to their reliance on probabilistic modeling. Instead, deterministic equivalents are used.").

131 *Id.* at 4.

132 Kevin Carden et al., *supra* note 50, at 2; Energy Sys. Integration Grp., New Resource Adequacy Criteria, *supra* note 6, at 6.

133 Juan Pablo Carvallo et al., *supra* note 8, at 11 ("The LOLE is typically used as a target setting metric and has historically taken a value of 1 event-day in 10 years, commonly (and incorrectly) interpreted as 2.4 hours per year.").

134 Gord Stephen et al., *supra* note 15, at 3, https://perma.cc/A9DJ-C3B5.

135 U.S. Dep't of Energy, Resource Adequacy Report, *supra* note 2, at 4 n.10.

136 N. Am. Elec. Reliability Corp., 2024 Long-Term Reliability Assessment, *supra* note 51, at 141.

137 U.S. Dep't of Energy, National Transmission Planning Study: Chapter 2: Long-Term U.S. Transmission Planning Scenarios 4, 82 (2024), https://perma.cc/R8RA-23E2.

Finally, at times, the DOE Study appears to struggle with the very meaning of a resource adequacy standard: It questions both PJM's and SPP's resource adequacy, even though each satisfies the metrics DOE's itself picked for its analysis. For PJM in particular, DOE notes that the region currently satisfies both prongs of the resource adequacy metric, but not for the particular weather year that includes Winter Storm Elliot.[138] Seemingly for this reason, DOE concludes that PJM needs 2.4 GW of additional perfect capacity to be resource adequate now.[139] But DOE's resource adequacy targets are, in DOE's own words, "average indicators" to be achieved across all modeled scenarios, not a requirement that must be achieved in each and every scenario.[140] PJM is resource adequate today according to DOE's targets.

Of course, as discussed in Part 1, it may be reasonable for a system planner to set a resource adequacy target that depends, in part, on each region's performance during tail risks. But DOE has not done so here.

## Resource Adequacy Modeling

DOE's resource adequacy modeling is inconsistent with best practices. DOE's high-level decisions about the study's overall modeling approach and data input decisions both diverge from the best practices described in Part 1.

### Deterministic Model

While the DOE Study appropriately examines all 8,760 hours of the year in chronological order,[141] DOE departs from best practices by using deterministic modeling rather than a probabilistic approach (like the Monte Carlo method), perhaps because of the EO's relatively short timeline.[142] Rather than randomly sampling probability distributions for each input to construct hundreds or thousands of plausible scenarios, DOE "evaluates whether a power system has sufficient resources . . . under a pre-defined set of conditions which correspond to the past few years of real-world events."[143] DOE uses twelve years of data (2007–2013 and 2019–2023) for weather, load, and generation.[144]

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138 U.S. Dep't of Energy, Resource Adequacy Report, *supra* note 2, at 7, 9, 27.

139 *Id.* at 9.

140 *Id.* at 7.

141 *See* U.S. Dep't of Energy, Resource Adequacy Report, *supra* note 2, at 10, 12–13.

142 *Id.* at 2. The EO provided an extremely accelerated deadline of 90-days for DOE to produce results. *See* Exec. Order No. 14,262, Strengthening the Reliability and Security of the United States Electric Grid, 90 Fed. Reg. 15521, 15521 (Apr. 14, 2025). The DOE Study itself provides additional evidence for this conclusion, with its acknowledgement that "[p]robabilistic approaches incorporate data and advanced modeling techniques to represent uncertainty" but "require more computing power." U.S. Dep't of Energy, Resource Adequacy Report, *supra* note 2, at 2 n.2.

143 U.S. Dep't of Energy, Resource Adequacy Report, *supra* note 2, at 10.

144 *Id.* at 11. While DOE uses historical data for the years 2019–2023, it uses "synthetic" data for 2007–2013. *Id.* "The synthetic approach used historical weather data to estimate load and resource availability if those same weather conditions were to occur again in the future. The historic approach used historical measured data for load, as well as wind and solar resource output, from recent years and scaled it appropriately to represent future conditions." N. Am. Elec. Reliability Corp., Interregional Transfer Capability Study, *supra* note 128, at 74.

By examining whether regions would be resource adequate only under conditions that resemble the recent past, DOE's study does not sufficiently account for uncertainty. Indeed, in the Interregional Transfer Capability Study, from which DOE borrowed, NERC itself explains the limitations of this same deterministic approach and same data: Some regions may look resource adequate because they happened to do well during the twelve years of data, while others look resource inadequate but be unlikely to perform as poorly in the future.[145] Addressing the deterministic vs. probabilistic distinction, NERC cautions that, because a "[p]robabilistic resource adequacy analysis was not conducted[,] . . . . the [Interregional Transfer Capability Study] should not be considered a North American resource adequacy assessment."[146]

DOE grounds its use of a deterministic model in "transparency" and an interest in "model[ing] detailed historic system conditions."[147] Neither is a reason to step away from best practices: DOE could document a probabilistic approach in a transparent way, and relying on a small sample of historic years is less accurate than a probabilistic approach. Given the high stakes associated with resource adequacy planning, any future DOE resource adequacy assessment should prioritize accuracy over expediency.

### Outage Threshold

Another modeling choice is the threshold for determining when a shortfall event has occurred. DOE projects a shortfall if "the remaining capacity after transmission and demand response falls below the 6 percent or 3 percent needed for error forecasting and ancillary services, depending on the scenario."[148] This choice means that DOE identifies shortfall events in the hours when, after exhausting imports and demand response, a region's excess energy falls below 6% or 3% of hourly load—but it is not clear when DOE uses 6% versus 3%. DOE states that more details are available in a section of the study's appendix entitled "Outputs," but, as of publication of this report, no such section appears to be available.[149]

NERC uses a 3% threshold in its Interregional Transfer Capability Study, using 6% only in a sensitivity analysis.[150] According to NERC, the 3% value "was established based on an evaluation of average reserve requirements where load shed may occur" and reflects how "a Balancing Authority will continue to hold reserves even if involuntary load shed is underway to safeguard the system from cascading or widespread outages."[151] It is impossible to tell from the DOE Study when DOE used 6% versus 3%, but the fact that DOE listed 6% first may suggest that 6% was not limited to a sensitivity analysis.

If DOE's model instead identifies shortage events even when a region still has 6% of load available as spare capacity, then DOE's results depart from NERC's practice and may overstate

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145 *Id.* at 138.
146 *Id.* at 4.
147 U.S. Dep't of Energy, Resource Adequacy Report, *supra* note 2, at 2 n.2.
148 *Id.* at 12.
149 *Id.*
150 N. Am. Elec. Reliability Corp., Interregional Transfer Capability Study, *supra* note 128, at 84.
151 *Id.* at 91 n.90, 85.

the extent of expected outages. In NERC's Interregional Transfer Capability Study, this change alone *significantly* altered the existence and extent of predicted outages in many regions, such as producing a 690% increase in the size of the maximum outage event in SERC-Florida.[152] Under the 6% sensitivity, NERC also recommended 58 GW of transmission additions to address resource adequacy instead of 35 GW, illustrating the sizable influence of shifting this assumption from 3% to 6%.[153]

## Inputs

DOE's prediction that most regions will experience resource inadequacy by 2030 depends heavily on its assumptions about resource additions, retirements, load growth, and interregional imports. In each instance, DOE makes choices that raise significant questions about the validity of its modeling results.

### *Additions*

DOE assumes that the only resource additions by 2030 will be those NERC currently categorizes as "Tier 1."[154] To be a Tier 1 resource, the resource must have achieved at least one milestone from a NERC list that signifies the unit is "very mature in the development pipeline."[155] This assumption is very conservative: The study itself admits that "[t]his results in minimal capacity additions beyond 2026."[156] In other words, DOE's finding of widespread resource inadequacy in 2030 rests on the assumption that very little will be built from 2027–2030. For example, NERC identifies 17,047 MW of Tier 1 resources slated to come online in PJM throughout 2025 and 2026, but only 1,108 MW from 2027–2030.[157]

The drop-off in Tier 1 resources after 2026 is not due to a shortage of projects in development, but rather because NERC currently classifies much of the capacity that will come online between 2027 and 2030 as "Tier 2."[158] Tier 2 resources occupy a wide range of positions in the interconnection queue, from the earliest stages (e.g., those having completed a feasibility study) to the very end

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152 *Id.* at 105 tbl.8.4

153 *Id.*

154 U.S. Dep't of Energy, Resource Adequacy Report, *supra* note 2, at 4.

155 *Id.* at A-5. More specifically, the resource must have finished construction, be under construction, have a signed/approved interconnection service agreement, have a signed/approved power purchase agreement, have a signed/approved construction service agreement, have a signed/approved wholesale market participant agreement, or (if it is in the footprint of a vertically integrated utility) be included in an integrated resource plan or under a regulatory environment that mandates a resource adequacy requirement. N. Am. Elec. Reliability Corp., 2024 Long-Term Reliability Assessment, *supra* note 51, at 137.

156 U.S. Dep't of Energy, Resource Adequacy Report, *supra* note 2, at A-5. *See also* Ric O'Connell, *GridLab Analysis: Department of Energy Resource Adequacy Report*, GridLab (July 11, 2025), https://perma.cc/B3GC-T7GA ("The report assumes just 22 GW of new 'firm' capacity (narrowly defined as gas) is added which is based on NERC LTRA 'Tier 1' – projects with a very high likelihood of success. The report assumes no projects are built post 2026, which is not realistic for a report forecasting to 2030. A more reasonable assumption for capacity additions is the EIA 860 released in June, which has 35 GW of gas additions, and another 53 GW of batteries – **88 GW of firm additions by 2030**.") (bolded text in original).

157 N. Am. Elec. Reliability Corp., 2024 Long-Term Reliability Assessment, *supra* note 51, at 89.

158 *See id.* at 137.

of the process (e.g., those that have requested an interconnection service agreement).[159]

In recent years, the median project has taken approximately 55 months (4.58 years) to go from entering the queue to commercial operation.[160] Extrapolating from this historical trend reveals that a large number of Tier 2 resources will likely be operating by 2030. DOE should have anticipated some of them in the 2030 resource mix, and it departed from best practices by excluding all Tier 2 resources.[161] To do this forecasting accurately, DOE should have examined historical statistics of interconnection queue time by region, resource type, and resource size, along with differentiated queue withdrawal rates, estimating Tier 2 resource additions for each region.[162]

And applying historical statistics for time spent in a region's interconnection queue would itself be a conservative methodology for DOE to use, as FERC Order 2023 and related regional interconnection queue updates are set to speed up waiting times.[163] For example, the DOE Study found a 10.5 GW resource adequacy deficit for PJM in 2030 but failed to consider the almost 12 GW of nameplate capacity—mostly gas—that PJM is fast-tracking through its Reliability Resource Initiative.[164] PJM expects that 90% of this capacity will be online by 2030.[165] PJM is simultaneously pursuing other resource adequacy interventions, including a FERC-approved change to surplus interconnection service (to allow new generators to come online faster by taking advantage of underutilized transmission capacity),[166] and a FERC-pending proposal to expedite the process to transfer capacity interconnection rights from retiring generators to new resources.[167]

Finally, recently "retired" resources represent another potential source of fast additions.[168]

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159 *Id.*

160 Joseph Rand et al., Lawrence Berkeley Nat'l Lab'y, Queued Up: 2024 Edition: Characteristics of Power Plants Seeking Transmission Interconnection As of the End of 2023 41 (2024), https://perma.cc/5DE4-XNK6.

161 *See* N. Am. Elec. Reliability Corp., 2024 Long-Term Reliability Assessment, *supra* note 51, at 23 fig.2.

162 *See generally* Joseph Rand et al., Lawrence Berkeley Nat'l Lab'y, Queued Up: 2024 Edition: Characteristics of Power Plants Seeking Transmission Interconnection As of the End of 2023 (2024), https://perma.cc/5DE4-XNK6.

163 *Improvements to Generator Interconnection Procedures and Agreements*, 184 FERC ¶ 61,054 (2023).

164 Donnie Bielak, PJM, Reliability Resource Initiative: Additional Summaries 2 (2025), https://perma.cc/Y2AB-3CEM; Donnie Bielak, PJM, Reliability Resource Initiative: Results Summary 6 (2025), https://perma.cc/MYQ8-Y53G. *See also* Ric O'Connell, *supra* note 156 ("The study ignores both utility plans for meeting increased load growth and how markets will respond. In fact, markets and utilities have already responded with plans to add new capacity and fast track new resources. These include PJM's Reliability Resource Initiative, which plans on adding 11 GW of new firm resources by 2030. SPP and MISO both have proposals at FERC (called ERAS) that will likely add another 30 GW of firm resources. Those three regional efforts alone would add roughly twice what the DOE assumed for the entire nation.").

165 *PJM Chooses 51 Generation Resource Projects To Address Near-Term Electricity Demand Growth*, PJM Inside Lines (May 2, 2025), https://perma.cc/8EW2-G2XZ.

166 *PJM Interconnection, L.L.C.*, 190 FERC ¶ 61,083 (2025).

167 Proposed Revisions to PJM's Open Access Transmission Tariff, PJM, Docket No. ER25-____-000 (Jan. 31, 2025), https://perma.cc/J9T3-MCGL.

168 *E.g.*, Francisco "A.J." Camacho & Daviel Schulman, *Mothballed Nuclear Plant on Brink of Revival*, EnergyWire (July 15, 2025), https://subscriber.politicopro.com/article/eenews/2025/07/15/mothablled-nuclear-plant-on-brink-of-revival-00445239.

### *Retirements*

DOE's assumption that 104 GW of nameplate capacity will retire by 2030 likely overestimates retirements.[169] This number includes both "confirmed" retirements—resources that have notified their system operators of their impending retirements and begun the retirement process—and "announced" retirements—which are publicly stated but not officially noticed.[170] These data come from NERC's Long-Term Reliability Assessment 2024 model.[171] In turn, NERC receives reports of confirmed retirements directly from each region, while announced retirements come from multiple sources, including Energy Information Agency Form 860 data, trade press, and utility integrated resource plans.[172]

These data likely overestimate retirements.[173] First, the economics of energy production have changed since 2024. The combined effect of new demand from data centers and the elimination of federal tax credits for new wind and solar resources improves the financial outlook for thermal resources.[174] Second, federal environmental regulations that would have required thermal resources to make investments reducing their pollution or else retire were projected to result in significant retirements before 2030.[175] But the Trump Administration has begun to rescind or reexamine these rules, which could cause resources to delay their retirements.[176]

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169 *See* U.S. Dep't of Energy, Resource Adequacy Report, *supra* note 2, at 5.

170 *Id.* at 12.

171 *Id.*

172 N. Am. Elec. Reliability Corp., 2024 Long-Term Reliability Assessment, *supra* note 51, at 28 n.19.

173 Ric O'Connell, *supra* note 156 ("The report assumed 104 GW of retirements by 2030, with 3/4 of this coal and 1/4 gas. But the most recent data from the U.S. Energy Information Administration released in June (the EIA 860) has just **half** of this capacity retiring. In the report, the DOE assumed these 50 GW of likely retirements, but included another 50 GW of *announced* retirements, inconsistent with their assumption around capacity additions. Most likely many plants will choose not to retire due to the changing regulatory and economic landscape, driven by the administration's policies.") (bolded text in original).

174 Aurora Energy Research, Impact of Reform to Clean Energy Tax Credits on Investment, Jobs and Consumer Bills 10 (2025), https://perma.cc/VHR5-UEGP; ("Most demand is made up through more production from existing plants (35%), meaning these plants are running for longer hours and/or at higher output levels. Some projects that retired in the base case scenario see longer lifetimes in Tax Credit Removal scenario because of more favorable economics due to clean energy decline (making up 17% of lost generation), and the rest is made up for by new build thermal plants (29%)."); Energy Innovation Pol'y & Tech. LLC, Federal Clean Energy Tax Credits Make Energy More Affordable—A Meta-Analysis (2025) https://perma.cc/QH2E-7PLL ("The research is clear—repealing technology-neutral energy tax credits would raise annual energy bills up to $140–$220 per year nationally, and over $500 per year in some states."). *See also* Ethan Howland, *PJM Capacity Prices Hit Record Highs, Sending Build Signal to Generators*, Utility Dive (July 31, 2024), https://perma.cc/UC6U-QHYT ("Prices in the PJM Interconnection's latest capacity auction hit record highs, which should provide incentives for power plant companies to build new generating resources and keep existing ones operating, according to the grid operator."); Ethan Howland, *MISO Summer Capacity Prices Jump to $666.50/MW-day as Power Supplies Shrink*, Utility Dive (Apr. 29, 2025), https://perma.cc/A6S5-4A4U ("Capacity prices for the upcoming summer season jumped to $666.50/MW-day from $30/MW-day last year across the Midcontinent Independent System Operator's footprint—driven in part by declining surplus capacity, according to the results of its latest planning resource auction released Monday.").

175 PJM, Energy Transition in PJM: Resource Retirements, Replacements & Risks 8 (2023), https://perma.cc/7J3A-FL8U.

176 *EPA Launches Biggest Deregulatory Action in U.S. History*, EPA (Mar. 12, 2025), https://perma.cc/55MN-2SUB.

### *Load*

The DOE Study assumes 50 GW of growth in data center load and 51 GW of additional non-data center load.[177] DOE does not account for the possibility that this data center load could be flexible, even as one study suggests that 76 GW of additional data center load could be accommodated today if it could be curtailed only 0.25% of the time, and relevant corporations have confirmed flexibility potential.[178]

In June 2025, Texas enacted a law that allows ERCOT to curtail certain new loads over 75 MW during emergencies.[179] DOE assumes an additional 8 GW of data center load in ERCOT by 2030 and finds a reliability shortfall of 10.5 GW (which is likely an overestimate for the reasons discussed elsewhere in this Part, including how this 10.5 GW brings ERCOT to 0.0008% NUSE instead of 0.002% NUSE).[180] Accordingly, Texas's new law could go a long way towards avoiding the DOE-identified resource adequacy problem. Other regions like PJM are considering strategies to soften the resource adequacy impact of data centers, including ways to better encourage their participation in demand response programs.[181] DOE should have considered the possibility that some of the projected data center load would be flexible, especially in ERCOT.

Additionally, how DOE chose to distribute the projected 50 GW of data center load across regions is questionable. The DOE Study explains it used state-level growth ratios to perform this allocation.[182] But it is unlikely that all the computing demand needs to be processed close to load centers (i.e., proportional to a region's current electric load). In fact, some computing demand

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177 U.S. Dep't of Energy, Resource Adequacy Report, *supra* note 2, at 2–3.

178 Tyler H. Norris et al., Nicholas Inst. for Energy, Env't & Sustainability, Rethinking Load Growth: Assessing the Potential for Integration of Large Flexible Loads in US Power Systems 2 (2025), https://perma.cc/6693-3HZU; *EPRI Launches Initiative to Enhance Data Center Flexibility and Grid Reliability,* Elec. Power Rsch. Inst. (Oct. 29, 2024), https://perma.cc/75LY-PSP5 ("Led by EPRI, DCFlex will coordinate real-world demonstrations of flexibility in a variety of existing and planned data centers and electricity markets, creating reference architectures and providing shared learnings to enable broader adoption of flexible operations that benefit all electricity consumers. Specifically, DCFlex will establish five to ten flexibility hubs, demonstrating innovative data center and power supplier strategies that enable operational and deployment flexibility, streamline grid integration, and transition backup power solutions to grid assets. Demonstration deployment will begin in the first half of 2025, and testing could run through 2027."); Anuja Ratnayake, *Unlocking AI Potential with Data Center Flexibility*, EnergyCentral (June 12, 2025), https://www.energycentral.com/intelligent-utility/post/unlocking-ai-potential-with-data-center-flexibility-PtPoXIAuRMzs5Ff ("In a preliminary test of the depth of computational flexibility possible in an AI data center, the Arizona demonstration site experienced some early success. It showcased the potential for an AI data center to provide grid relief during a peak system event—such as a hot summer day with high power demand—by temporarily and precisely ramping down its electricity consumption without compromising data center performance."). *See also* Ric O'Connell, *supra* note 156 ("It does not address flexibility of this load, however, which was recently demonstrated in a report from Duke University to allow for 100 GW of large load additions today with minimal grid impact.").

179 S.B. No. 6 § 4, 89th Legislature (Tex. 2025) (to be enacted at Tex. Util. Code § 39.170), https://perma.cc/4Z7H-9XKQ; Brian Martucci, *Texas Law Gives Grid Operator Power to Disconnect Data Centers During Crisis*, Utility Dive (June 25, 2025), https://perma.cc/SYK3-V4XX; Waleed Aslam & Robin Hytowitz, Elec. Power Rsch. Inst., Texas SB6 Explained: Addressing Large Load Impacts (2025), https://perma.cc/QD8S-3M5C.

180 U.S. Dep't of Energy, Resource Adequacy Report, *supra* note 2, at 40.

181 Tim Horger, PJM, Large Load Additions Workshop 28 (2025), https://perma.cc/4HSN-CW4W.

182 U.S. Dep't of Energy, Resource Adequacy Report, *supra* note 2, at 17.

may be served from other regions if it will be cheaper to integrate the data center elsewhere. Given the scale of DOE's projected data center load compared to the relatively small resource adequacy shortfalls that the study identifies, these assumptions may have made the difference between whether a region achieves DOE's resource adequacy targets.[183]

### *Interregional Imports*

The DOE Study states that it has adopted the interregional transfer capacities from NERC's Interregional Transfer Capability Study but also notes that transfers are "available up to the *minimum* total transfer capacity."[184] NERC's values describe the available transmission capacity between regions, including sub-regions of larger transmission-constrained regions like PJM, SPP, and MISO.[185] NERC provides a summer value and a winter value for each interregional interface and for each direction of flow.[186]

It is unclear what DOE means when it says that transfers are allowed up to their "minimum." If DOE picked the lesser of the summer and winter transfer capacities and applied that annually, doing so would inaccurately underestimate the amount of interregional transfer capacity.

## Accreditation & Reference Margin Levels

While DOE issued its study in response to the EO's request for a "methodology to identify current and anticipated regions with reserve margins below acceptable thresholds,"[187] it does so through resource adequacy modeling, rather than by calculating accreditation values and using them to derive reference margin levels. As explained in Part 2, properly performed resource adequacy modeling is sufficient to determine whether a region is resource adequate.

In contrast, accreditations and reference margin levels are useful in combination to quickly evaluate how the loss or addition of a particular resource would affect whether a region achieves its resource adequacy target without re-running regional resource adequacy modeling. They are thus more applicable to EO Section 3(c)'s separate command to establish a "protocol to identify which generation resources within a region are critical to system reliability.[188] Thus far, DOE has not released a study implementing this provision. DOE may eventually supplement the DOE Study with additional accreditation and reference margin level analyses.

Nonetheless, while the DOE Study does not calculate accreditation values or reference margin levels, it does undertake the related exercise of evaluating how much additional perfect capacity would bring certain regions to resource adequacy.[189] (DOE calculated these perfect capacity

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183 *See id.* at 9, 17.

184 *Id.* at 18, 12, A-1 (emphasis added).

185 N. Am. Elec. Reliability Corp., Interregional Transfer Capability Study, *supra* note 128, at 7, 9–10.

186 *Id.* at 17–24.

187 Exec. Order No. 14,262, Strengthening the Reliability and Security of the United States Electric Grid, 90 Fed. Reg. 15521, 15521 (Apr. 14, 2025).

188 *Id.* at 15522.

189 U.S. Dep't of Energy, Resource Adequacy Report, *supra* note 2, at 5.

additions for only four of the seven regions that failed to achieve 0.002% NUSE in 2030: PJM, SPP, SERC, and ERCOT—not MISO, CAISO, or West Non-CAISO.[190]) More specifically, DOE asked how much perfect capacity it would take for regions to achieve the 0.002% NUSE resource adequacy standard in 2030.[191]

If, in the future, DOE were to also calculate the accredited capacity of a region's fleet and then add the solved-for perfect capacity, it could calculate the region's reference margin level. Similarly, although DOE did not perform any perfect capacity analysis for regions that achieve 0.002% NUSE, DOE could subtract perfect capacity from the accredited capacity of the regional fleets to solve for reference margin levels. Once DOE calculates a region's reference margin, it could look at the accredited capacity of any resource to evaluate how its exit or entry would affect achievement of the reference margin level.

In calculating any reference margin levels, DOE should attend to all prongs of its multi-metric resource adequacy target. Here, DOE Study's perfect capacity exercise focuses exclusively on 0.002% NUSE. But if a region achieves 0.002% NUSE and not 2.4 LOLH, it would be resource inadequate according to the terms of this DOE Study. Separate reference margin levels may apply to each prong, and a region would be resource adequate only when the highest reference margin level is achieved.

Additionally, going forward, DOE should better prioritize accuracy in any new studies with respect to calculating a region's need for perfect capacity additions/subtractions. Critically, while DOE asserted that it added the amount of perfect capacity needed to bring each region to 0.002% NUSE, the 10.5 GW that it added to PJM actually brought it to 0.0003% NUSE; the 500 MW added to SERC brought it to 0.0002% NUSE; the 1.5 GW added to SPP brought it to 0.0002% NUSE; and the 10.5 GW added to ERCOT brought it to 0.0008% NUSE.[192] All of these values indicate significantly greater resource adequacy that 0.002% NUSE, sometimes by an order of magnitude.

While DOE explains that its perfect capacity additions were done "by hand with a limited number of iterations (15)" such that the capacity additions "should not be considered the minimum possible capacity to accomplish these targets," that approach does not appear to explain why DOE brought these regions far beyond the 0.002% NUSE target.[193] Rather, this explanation suggests that, for each of the regions, DOE could have achieved these high levels of resource adequacy using less perfect capacity than it added. Accordingly, to achieve 0.002% NUSE, DOE likely could have added much less perfect capacity than it did. Identifying resources that meet these overestimated capacity levels could result in overpaying to achieve a different resource adequacy target than selected.

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190 *Id.* at 20–42.
191 Id. at 5.
192 *Id.* at 27, 30, 32, 40.
193 *Id.* at 19.

# Part 3: Next Steps

Having reviewed best practices for resource adequacy modeling and the DOE Study, this final section discusses next steps for U.S. resource adequacy policy considering the diverse actors in this space and their respective authorities.

The Federal Power Act (FPA) gives FERC, and FERC's designated "Electric Reliability Organization" (ERO), NERC, jurisdiction over and responsibility for ensuring "[e]lectric reliability" for the "bulk power system," i.e., the high-voltage transmission network and the energy that flows through it.[194] More specifically, the FPA requires NERC to "establish and enforce reliability standards," which take effect after FERC approves them.[195] Importantly, FERC can also order NERC to submit reliability standards on particular topics and can independently enforce reliability standards.[196] NERC's six regional entities (comprising the continental U.S. plus Canada) also have authority to propose reliability standards to NERC.[197]

Achieving reliability arguably requires that bulk power system be resource adequate because, as FERC explains, "[i]f resources cannot meet load, or are insufficient to provide a reserve margin above expected load, then instability, uncontrolled separation or cascading failures can result from the unanticipated loss of a system element."[198] But, although reliable grid operations depend in part on resource adequacy, the FPA does not put FERC and NERC in the driver's seat for this aspect of reliability. FERC lacks authority to *directly achieve* resource adequacy because it cannot order construction of electric generation facilities.[199] Rather, states retain their traditional authority "over facilities used for the generation of electric energy,"[200] which some exercise by requiring utilities to submit integrated resource plans describing their plans to meet future demand.[201] Other states fully or partially delegate this authority to the Regional Transmission Organizations (RTOs) that operate their regional grids, e.g., by relying on the RTOs to achieve resource adequacy through capacity markets.[202]

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194 16 U.S.C. § 824o(a).

195 16 U.S.C. § 824o(a)(2), (d). FERC does not have authority to create reliability standards directly. *See id.* at § 824o(d).

196 16 U.S.C. § 824o(d)(5), (e)(3).

197 16 U.S.C. § 824o(e)(4); *ERO Enterprise; Regional Entities,* N. Am. Elec. Reliability Corp., https://perma.cc/EQ9E-BXJW.

198 *Planning Resource Adequacy Assessment Reliability Standard*, 134 FERC ¶ 61,212, at P 25 (2011). Reliable operation also encompasses a second aspect of reliability not implicated by the EO—operational reliability—which refers to "ability of the electric system to withstand sudden disturbances while avoiding cascading blackouts." Burçin Ünel & Avi Zevin, *supra* note 5, at 11.

199 16 U.S.C. § 824o(a)(3). The FPA also prohibits FERC from directing utilities to build transmission, and states retain primary siting authority for transmission. *See id.*; *Building for the Future Through Electric Regional Transmission Planning and Cost Allocation*, 187 FERC ¶ 61,068 at P258 (2024).

200 16 U.S.C. § 824(b)(1).

201 Coley Girouard, *Understanding IRPs: How Utilities Plan for the Future*, Advanced Energy United (Aug. 11, 2015), https://perma.cc/5MDN-26QY.

202 Dena Adler & Jennifer Danis, Inst. for Pol'y Integrity, Reducing Pollution Without Sacrificing Reliability 14–16

But FERC and NERC can still play an important role for resource adequacy: FERC and NERC, through reliability standards, can ensure grid operators are proactively conducting appropriate resource adequacy assessments and analyses. In Order No. 747, FERC approved a regional reliability standard for conducting resource adequacy assessments.[203] This enforceable reliability standard requires, at a minimum, that entities within the applicable footprint conduct an annual analysis of what reserve margin would be necessary to ensure no more than 0.1 LOLE, using specific inputs like the median load forecast and accounting for important factors like fuel availability.[204] This reliability standard does not require regions to actually achieve 0.1 LOLE, only to conduct the mandated analysis.[205] A future reliability standard could require regions to instead adopt best practices comparable to those described in Part 1.

Turning to DOE, the DOE Reorganization Act put emergency grid reliability powers in DOE's hands for addressing certain emergency situations. Section 202(c) of the FPA empowers DOE, upon the finding of an emergency, to require, among any things, "such generation . . . as in its judgment will best meet the emergency and serve the public interest."[206] Section 202(c) and its implementing regulations, along with the common understanding of the word "emergency," indicate that this authority is limited to unexpected events.[207] Additionally, DOE's implementing regulations indicate that a shortage caused by a resource's poor economics would not qualify as an emergency, unless the shortage is "imminent."[208] When promulgating these regulations, DOE noted that:

> DOE does not intend these regulations to replace prudent utility planning and system expansion. This intent has been reinforced in the final rule by expanding the "Definition of Emergency" to indicate that, while a utility may rely upon these regulations for assistance during a period of unexpected inadequate supply of electricity, it must solve long-term problems itself.[209]

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(2024), https://perma.cc/G6J3-9ZL4. These capacity markets are FERC-jurisdictional, and operate according to rules contained in tariffs filed with FERC, specifying particulars like demand curve type, resource accreditation, and formulas for calculating reserve margins. *See, e.g.*, *PJM Interconnection, L.L.C.*, 191 FERC ¶ 61,066, at P 8 (2025).

203 *Planning Resource Adequacy Assessment Reliability Standard*, 134 FERC ¶ 61,212, at P 1 (2011).

204 Standard BAL-502-RF-03, N. Am. Elec. Reliability Corp., https://perma.cc/9MB5-5H67.

205 *Planning Resource Adequacy Assessment Reliability Standard*, 134 FERC ¶ 61,212, at P 33 (2011) ("The only obligations under BAL-502-RFC-02 are analysis and documentation requirements. This regional Reliability Standard does not specify how the results of the analysis required in this standard are to be used. For example, BAL-502-RFC-02 does not require state commissions to use the resource assessment analysis resulting from BAL-502-RFC-02 for economic decisions regarding resource adequacy requirements.").

206 16 U.S.C. § 824a(c)(1).

207 16 U.S.C. § 824a(c)(1); 10 C.F.R. § 205.371; Burçin Ünel & Avi Zevin, *supra* note 5, at 37–38.

208 10 C.F.R. § 205.371 ("Situations where a shortage of electric energy is projected due solely to the failure of parties to agree to terms, conditions or other economic factors relating to service, generally will not be considered as emergencies unless the inability to supply electric service is imminent.").

209 Emergency Interconnection of Electric Facilities and the Transfer of Electricity to Alleviate an Emergency Shortage of Electric Power, 46 Fed. Reg. 39984, 39985 (Aug. 6, 1981) (codified at 10 C.F.R. pt. 205).

In a departure from prior practice,[210] DOE has now used this authority to prevent thermal plants from retiring.[211] These orders have already drawn challenges from multiple parties, including from a politically diverse coalition of utility regulators.[212] Parties argue, among other points, that the plants' retirements were not unexpected; that the regions would be resource adequate even without the plants; and that DOE's newly asserted authority over resource adequacy triggers the major questions doctrine.[213]

Having nationally set best practices and principles for determining resource adequacy in the face of rapidly escalating demand and the clean energy transition could be useful if they are well vetted and use appropriate legal constructs. The FPA in conjunction with the DOE Reorganization Act suggest that the appropriate course of action for the federal government to support resource adequacy would be for NERC and FERC to set national resource adequacy *planning* standards (not a national resource adequacy target) to help regions guard against potential resource adequacy risks that might materialize in the future, instead of allowing DOE to stretch its 202(c) emergency authorities.

The DOE study itself cautions, "the resource adequacy analysis that was performed in support of this study could benefit greatly from the in-depth engineering assessments which occur at the regional and utility level."[214] Despite DOE's press statement asserting that the study's methodology can help guide "guide Federal reliability interventions,"[215] presumably to address the EO's mandate that DOE find a way to routinize further 202(c) emergency orders,[216] the study reports a fundamental limitation for doing so: It does not find any near-term reliability risk from current levels of resource adequacy.

The study itself states that, "one of the key takeaways from this study process is the underscored 'call to action' for strengthened regional engagement, collaboration, and robust data exchange which are critical to addressing the urgency of reliability and security concerns that underpin our

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210 Cong. Rsch. Serv., Federal Power Act: The Department of Energy's Emergency Authority 4 (updated 2025), https://perma.cc/AU8L-VR55.

211 *DOE's Use of Federal Power Act Emergency Authority*, U.S. Dep't of Energy, https://perma.cc/DPB9-6B74.

212 Ethan Howland, *Groups Appeal DOE "Emergency" Order Keeping Michigan Plan Online*, Utility Dive (updated June 20, 2025), https://perma.cc/P9YZ-FNLK; Ethan Howland, *Eight Utility Regulators Challenge DOE Order Keeping Michigan Coal Plant* Open, Utility Dive (June 26, 2025), https://perma.cc/55FE-2RYR; Motion to Intervene and Request for Rehearing of the Joint Consumer Advocates, Dep't of Energy Order No. 202-25-4 (June 27, 2025), https://perma.cc/PD74-6CNC.

213 Request for Rehearing by Michigan Attorney General Dana Nessel, Dep't of Energy Order No. 202-25-3, at 27–31, 35–36 (June 18, 2025); Motion to Intervene and Request for Rehearing and Stay of Sierra Club et al., Dep't of Energy Order No. 202-25-3, at 29–36 (June 18, 2025), https://perma.cc/4MYN-MHZC; Petition to Intervene and Request for Rehearing of the Organization of MISO States, Inc., Dep't of Energy Order No. 202-25-3, at 2–6 (June 23, 2025), https://perma.cc/D3PG-56H2. *See also* Brief of the Institute for Policy Integrity at 4–13, V.O.S. Selections, Inc. v. Trump, No. 25-00066-GSK-TMR-JAR (Ct. Int'l Trade May 8, 2025), https://perma.cc/5Z4T-8CHG (describing the major questions doctrine).

214 U.S. Dep't of Energy, Resource Adequacy Report, *supra* note 2, at i.

215 *Department of Energy Releases Report on Evaluating U.S. Grid Reliability and Security*, U.S. Dep't of Energy (July 7, 2025), https://perma.cc/942V-L7VB.

216 *See* Exec. Order No. 14,262, Strengthening the Reliability and Security of the United States Electric Grid, 90 Fed. Reg. 15521, 15521–22 (Apr. 14, 2025).

collective economic and national security." And it presents a pathway to fulfill DOE's discussion of what will happen next: "The report will inform joint planning processes and help integrate modern metrics into national reliability assessment methodology."[217] FERC directing NERC to develop national resource adequacy planning metrics, protocols, and input parameters would fit neatly within this call to action.

[217] *Reliability*, U.S. Dep't of Energy, https://perma.cc/RSW3-FNN2.

# Conclusion

Given ever-increasing demand for electricity—proliferation of data centers for artificial intelligence; electrification of heating, cooling, and transportation; and pushes to onshore manufacturing—maintaining resource adequacy is essential. But there is no single answer to the question of when a system is resource adequate, or even what constitutes resource adequacy. Still, as this report explains, there are better and worse ways to pick resource adequacy targets, to evaluate whether the system has achieved and will maintain them, and to understand the resource adequacy impacts of a particular resource entering or exiting the system. The DOE Study uses some of these best practices but not other important ones, undermining the accuracy of its predictions. The DOE Study will hopefully focus additional attention on resource adequacy and speed up federal and state endeavors already underway to bolster resource adequacy. It does not, however, provide a rational basis for DOE to take action now to thwart ongoing plans for uneconomic, aging resources to retire. DOE's next best step would be to request that FERC open a proceeding eliciting proposals for nationwide, enforceable reliability standards mandating not a national resource adequacy target, but best practices for grid planners to conduct resource adequacy assessments. Additionally, states and grid operators should continue working together to expedite resource permitting, better forecast what hyperscaler demand will materialize, engage in holistic transmission planning, and speed interconnection queues—all of which will support future resource adequacy.

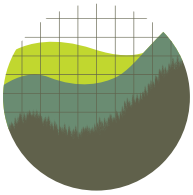

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Exhibit to
Motion to Intervene and Request for Rehearing and Stay of
Public Interest Organizations

Exhibit 2-42:
GridLab Report

1

# GridLab Analysis: Department of Energy Resource Adequacy Report



Ric OConnell

Rethinking Reliability

July 11, 2025

# Overview:

This memo provides a high-level overview of the recently released Department of Energy (DOE) Resource Adequacy Report, released on July 7, 2025. This report is a result of the Executive Order from the Trump Administration on Strengthening the Reliability and Security of the Grid, which directed the agency to develop and publish a methodology for "analyzing current and anticipated reserve margins for all regions of the bulk power system regulated by the Federal Energy Regulatory Commission and shall utilize this methodology to identify current and anticipated regions with reserve margins below acceptable thresholds as identified by the Secretary of Energy."

The Executive Order also directs the DOE to prevent generation sources exceeding 50 MW from retiring or converting fuel sources if it would reduce generating capacity in at-risk regions, based on the new methodology. The DOE has so far issued two emergency orders under section 202(c) of the Federal Power Act. These orders directed plant owners and grid operators to delay by 90 days the retirement of the Campbell coal plant in Michigan owned by Consumers Energy and the Eddystone gas and oil plant in Pennsylvania, owned by Constellation. The EO and its methodology report did not include a mechanism for public input.

# Bottomline of the DOE report:

The report warns of a 100X increased risk of outages if the forecasted retirements by 2030 take place. The report blames the lack of "firm" generation replacement in the planned supply.

# Bottomline of GridLab analysis:

The report's conclusions are problematic since the **report undercounts the resources that are likely to be added to the grid,** and **overstates** the retirements expected. Utilities and markets *already* have plans to meet increased load growth, yet the **DOE report assumes they are doing nothing after 2026**

the **DOE report assumes they are doing nothing after 2026.**

# DOE Report Analysis – Key Takeaways:

- The report is based on three key assumptions: (1) the amount of load that will be added to the grid over the next five years, (2) the number of plants assumed to retire, and (3) the amount of new capacity added to the grid. The study used aggressive assumptions regarding load growth and retirements, but conservative assumptions about how much new generation capacity will be added, even assuming no new resources after 2026.
    - Load Growth: The report assumes 50 GW of data center load and allocates it regionally. It does not address flexibility of this load, however, which was recently demonstrated in a report from Duke University to allow for 100 GW of large load additions today with minimal grid impact. The DOE report then adds 51 GW of non-data center load, which means overall load growth by 2030 is 101 GW or 15%. For comparison, EIA assumed 6% growth in their Annual Energy Outlook 2025 high growth case. This is very aggressive load growth, although not necessarily unreasonable, as it is collected from each of the RTOs and utilities.
    - Retirements: The report assumed 104 GW of retirements by 2030, with 3/4 of this coal and 1/4 gas. But the most recent data from the U.S. Energy Information Administration released in June (the EIA 860) has just **half** of this capacity retiring. In the report, the DOE assumed these 50 GW of likely retirements, but included another 50 GW of *announced* retirements, inconsistent with their assumption around capacity additions. Most likely many plants will choose

not to retire due to the changing regulatory and economic landscape, driven by the administration's policies.

- Capacity Additions: The report assumes just 22 GW of new "firm" capacity (narrowly defined as gas) is added which is based on NERC LTRA "Tier 1" – projects with a very high likelihood of success. The report assumes no projects are built post 2026, which is not realistic for a report forecasting to 2030. A more reasonable assumption for capacity additions is the EIA 860 released in June, which has 35 GW of gas additions, and another 53 GW of batteries – **88 GW of firm additions by 2030.**

- The study ignores both utility plans for meeting increased load growth and how markets will respond. In fact, markets and utilities have already responded with plans to add new capacity and fast track new resources. These include PJM's Reliability Resource Initiative, which plans on adding 11 GW of new firm resources by 2030. SPP and MISO both have proposals at FERC (called ERAS) that will likely add another 30 GW of firm resources. Those three regional efforts alone would add roughly twice what the DOE assumed for the entire nation.
- This national report attempts to address what is primarily a regional issue with regional solutions. A handful of regions face pressure due to rising load growth, and those regions have already enacted plans to address this growth. For example, MISO, SPP and PJM have all instituted "fast track" processes to get firm generation online (gas and batteries), which is expected to install 43 GW of new resources by 2030. The DOE report, however, shows just 13.5 GW of new firm resources in those three regions.

## DOE Report Assumptions vs. U.S. Energy Information Administration

## Energy Information Administration Data:

| | DOE Report | EIA 860 |
|---|---|---|
| Load growth: | 101 GW | N/A |
| Capacity Additions | 209 GW | 200 GW |
| Gas Capacity Additions | 22 GW | 35 GW |
| Battery Capacity Additions | 31 GW | 53 GW |
| Retirements | 104 GW | 52 GW |

Previous post
**London Calling: How UK Grid Innovation ...**


## Conclusion:

If the DOE report had used more consistent assumptions, it would have likely come to very different conclusions. Utilities and RTOs have planning processes and market mechanisms in place to build new resources in response to higher load growth and the retirement of older, uneconomic plants. The DOE's solution to keep older units online past retirement dates is a crude and expensive approach. The DOE should defer to state planning processes and regional markets to meet the challenge.

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| Authority, Salt River Project, | ) |
| PacifiCorp, and Xcel Energy | ) |

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Public Interest Organizations

Exhibit 2-43:
Duke University Rethinking Load Growth Study

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# Rethinking Load Growth

## Assessing the Potential for Integration of Large Flexible Loads in US Power Systems

Tyler H. Norris, Tim Profeta, Dalia Patino-Echeverri, and Adam Cowie-Haskell

Nicholas Institute for Energy, Environment & Sustainability nicholasinstitute.duke.edu

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# INTRODUCTION

## A New Era of Electricity Demand

Rapid US load growth—driven by unprecedented electricity demand from data centers, industrial manufacturing, and electrification of transportation and heating—is colliding with barriers to timely resource expansion. Protracted interconnection queues, supply chain constraints, and extended permitting processes, among other obstacles, are limiting the development of new power generation and transmission infrastructure. Against this backdrop, there is increasing urgency to identify strategies that accommodate rising demand without compromising reliability, affordability, or progress on decarbonization.

Aggregated US winter peak load is forecasted to grow by 21.5% over the next decade, rising from approximately 694 GW in 2024 to 843 GW by 2034, according to the *2024 Long-Term Reliability Assessment* of the North American Electric Reliability Corporation. This represents a 10-year compound annual growth rate (CAGR) of 2.0%, higher than any period since the 1980s (NERC 2024). Meanwhile, the Federal Energy Regulatory Commission's (FERC) latest five-year outlook forecasts 128 GW in peak load growth as early as 2029—a CAGR of 3.0% (FERC 2024b).

The primary catalyst for these updated forecasts is the surge in electricity demand from large commercial customers. While significant uncertainty remains, particularly following the release of DeepSeek, data centers are expected to account for the single largest growth segment, adding as much as 65 GW through 2029 and up to 44% of US electricity load growth through 2028 (Wilson et al. 2024; Rouch et al. 2024). Artificial intelligence (AI) workloads are projected to represent 50% to 70% of data center demand by 2030—up from less than 3% at the start of this decade—with generative AI driving 40% to 60% of this growth (Srivathsan et al. 2024; Lee et al. 2025).

Analysts have drawn parallels to the 1950s through the 1970s, when the United States achieved comparable electric power sector growth rates (Wilson et al. 2024). Yet these comparisons arguably understate the nature of today's challenge in the face of stricter permitting obstacles, higher population density, less land availability, skilled labor shortages, persistent supply chain bottlenecks, and demand for decarbonization and greater power reliability. While historical growth rates offer a useful benchmark, the sheer volume of required new generation, transmission, and distribution capacity forecasted for the United States within a condensed timeframe appears unprecedented.

The immensity of the challenge underscores the importance of deploying every available tool, especially those that can more swiftly, affordably, and sustainably integrate large loads. The time-sensitivity for solutions is amplified by the market pressure for many of these loads to interconnect as quickly as possible. In recent months, the US Secretary of Energy Advisory Board (SEAB) and the Electrical Power Research Institute (EPRI) have highlighted a key solution: load flexibility (SEAB 2024, Walton 2024a). The promise is that the unique profile of AI data centers can facilitate more flexible operations, supported by ongoing advancements in distributed energy resources (DERs).

Flexibility, in this context, refers to the ability of end-use customers to temporarily reduce their electricity consumption from the grid during periods of system stress by using on-site generators, shifting workload to other facilities, or reducing operations.[1] When system planners can reliably anticipate the availability of this load flexibility, the immediate pressure to expand generation capacity and transmission infrastructure can potentially be alleviated, mitigating or deferring costly expenditures. By facilitating near-term load growth without prematurely committing to large-scale capacity expansion, this approach offers a hedge against mounting uncertainty in the US data center market in light of the release of DeepSeek and related developments (Kearney and Hampton 2025).

## Summary of Analysis and Findings

To support evaluation of potential solutions, this study presents an analysis of the existing US electrical power system's ability to accommodate new flexible loads. The analysis, which encompasses 22 of the largest balancing authorities serving 95% of the country's peak load, provides a first-order estimate of the potential for accommodating such loads with minimal capacity expansion or impact on demand-supply balance.[2]

Specifically, we estimate the gigawatts of new load that could be added in each balancing authority (BA) before total load exceeds what system planners are prepared to serve, provided the new load can be temporarily curtailed as needed. This serves as a proxy for the system's ability to integrate new load, which we term *curtailment-enabled headroom*.

Key results include (see Figure 1):

- 76 GW of new load—equivalent to 10% of the nation's current aggregate peak demand—could be integrated with an average annual load curtailment rate of 0.25% (i.e., if new loads can be curtailed for 0.25% of their maximum uptime)
- 98 GW of new load could be integrated at an average annual load curtailment rate of 0.5%, and 126 GW at a rate of 1.0%
- The number of hours during which curtailment of new loads would be necessary per year, on average, is comparable to those of existing US demand response programs
- The average duration of load curtailment (i.e., the length of time the new load is curtailed during curtailment events) would be relatively short, at 1.7 hours when average annual load curtailment is limited to 0.25%, 2.1 hours at a 0.5% limit, and 2.5 hours at a 1.0% limit
- Nearly 90% of hours during which load curtailment is required retain at least half of the new load (i.e., less than 50% curtailment of the new load is required)
- The five balancing authorities with the largest potential load integration at 0.5% annual curtailment are PJM at 18 GW, MISO at 15 GW, ERCOT at 10 GW, SPP at 10 GW, and Southern Company at 8 GW[3]

1 Note that while *curtailment* and *flexibility* are used interchangeably in this paper, *flexibility* can refer to a broader range of capabilities and services, such as the provision of down-reserves and other ancillary services.

2 For further discussion on the nuances regarding generation versus transmission capacity, see the section on limitations.

3 A complete list of abbreviations and their definitions can be found at the end of the report.

Overall, these results suggest the US power system's existing headroom, resulting from intentional planning decisions to maintain sizable reserves during infrequent peak demand events, is sufficient to accommodate significant constant new loads, provided such loads can be safely scaled back during some hours of the year. In addition, they underscore the potential for leveraging flexible load as a complement to supply-side investments, enabling growth while mitigating the need for large expenditures on new capacity.

We further demonstrate that a system's potential to serve new electricity demand without capacity expansion is determined primarily by the system's load factor (i.e., a measure of the level of use of system capacity) and grows in proportion to the flexibility of such load (i.e., what percentage of its maximal potential annual consumption can be curtailed). For this reason, in this paper we assess the technical potential for a system to serve new load under different curtailment limit scenarios (i.e., varying curtailment tolerance levels for new loads).

The analysis does not consider the technical constraints of power plants that impose intertemporal constraints on their operations (e.g., minimum downtime, minimum uptime, startup time, ramping capability, etc.) and does not account for transmission constraints. However, it ensures that the estimate of load accommodation capacity is such that total demand does not exceed the peak demand already anticipated for each season by system planners, and it discounts existing installed reserve margins capable of accommodating load that exceeds historical peaks. It also assumes that new load is constant throughout all hours.

This analysis should not be interpreted to suggest the United States can fully meet its near- and medium-term electricity demands without building new peaking capacity or expanding the grid. Rather, it highlights that flexible load strategies can help tap existing headroom to more quickly integrate new loads, reduce the cost of capacity expansion, and enable greater focus on the highest-value investments in the electric power system.

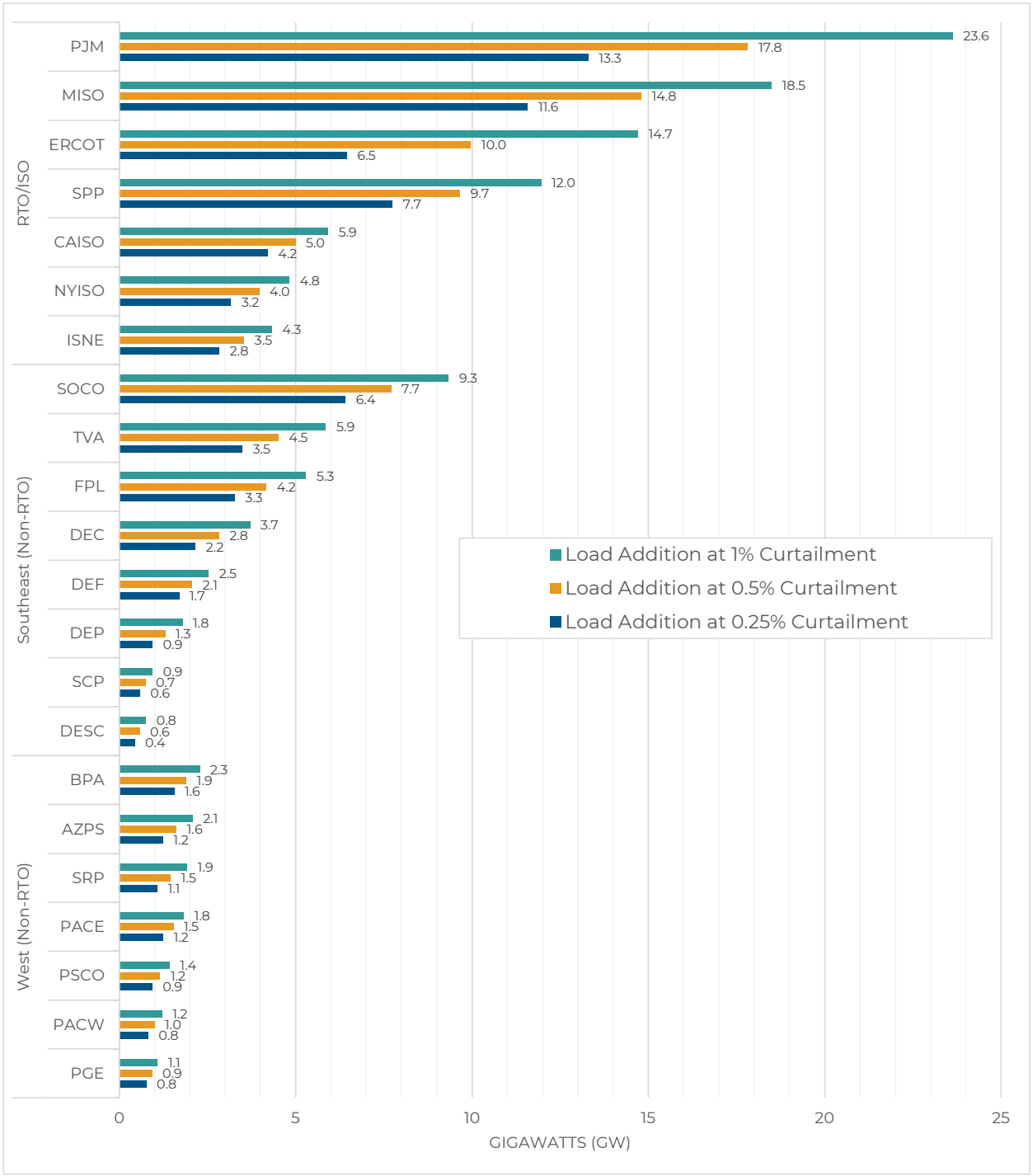
This paper proceeds as follows: the following section provides background on the opportunities and challenges to integrating large new data centers onto the grid. It explores how load flexibility can accelerate interconnection, reduce ratepayer costs through higher system utilization, and expand the role of demand response, particularly for AI-specialized data centers. We then detail the methods and results for estimating curtailment-enabled headroom, highlighting key trends and variations in system headroom and its correlation with load factors across regions. The paper concludes with a brief overview of key findings, limitations, and near-term implications.

## BACKGROUND

### Load Flexibility Can Accelerate Grid Interconnection

The growing demand for grid access by new large loads has significantly increased interconnection wait times, with some utilities reporting delays up to 7 to 10 years (Li et al. 2024; Saul 2024; WECC 2024). These wait times are exacerbated by increasingly severe transmission equipment supply chain constraints. In June 2024, the President's National Infrastructure Advisory Council highlighted that transformer order lead times had ballooned to two to five years—up from less than one year in 2020—while costs surged by 80% (NIAC 2024). Circuit breakers have seen similar delays: last year, the Western Area Power Administration

## Figure 1. System Headroom Enabled by Load Curtailment of New Load by Balancing Authority, GW




Note: *System headroom* refers to the amount of GW by which a BA's load can be augmented every hour in the absence of capacity expansion so that, provided a certain volume of curtailment of the new load, the total demand does not exceed the supply provisioned by system planners to withstand the expected highest peak. The headroom calculation assumes the new load is constant and hence increases the total load by the same GW hour-by-hour.

reported lead times of up to four and a half years for lower voltage classes and five and a half years for higher voltage classes, alongside a 140% price hike over two years (Rohrer 2024). Wood Mackenzie reported in May 2024 that lead times for high-voltage circuit breakers reached 151 weeks in late 2023, marking a 130% year-over-year increase (Boucher 2024).

Large load interconnection delays have recently led to growing interest among data centers in colocating with existing generation facilities. At a FERC technical conference on the subject in late 2024 (FERC 2024c), several participants highlighted the potential benefits of colocation for expedited interconnection,[4] a view echoed in recent grey literature (Schatzki et al. 2024). Colocation, however, represents only a portion of load interconnections and is not viewed as a long-term, system-wide solution.

Load flexibility similarly offers a practical solution to accelerating the interconnection of large demand loads (SIP 2024, Jabeck 2023). The most time-intensive and costly infrastructure upgrades required for new interconnections are often associated with expanding the transmission system to deliver electricity during the most stressed grid conditions (Gorman et al. 2024). If a new load is assumed to require firm interconnection service and operate at 100% of its maximum electricity draw at all times, including during system-wide peaks, it is far more likely to trigger the need for significant upgrades, such as new transformers, transmission line reconductoring, circuit breakers, or other substation equipment.

To the extent a new load can temporarily reduce (i.e., curtail) its electricity consumption from the grid during these peak stress periods, however, it may be able to connect while deferring—or even avoiding—the need for certain upgrades (ERCOT 2023b). A recent study on Virginia's data center electricity load growth noted, "Flexibility in load is generally expected to offset the need for capacity additions in a system, which could help mitigate the pressure of rapid resource and transmission expansion" (K. Patel et al. 2024). The extent and frequency of required curtailment would depend on the specific nature of the upgrades; in some cases, curtailment may only be necessary if a contingency event occurs, such as an unplanned transmission line or generator outage. For loads that pay for firm interconnection service, any period requiring occasional curtailment would be temporary, ending once necessary network upgrades are completed.[5] Such "partially firm," flexible service was also highlighted by participants in FERC's 2024 technical conference on colocation.[6]

Traditionally, such arrangements have been known as *interruptible* electric service. More recently, some utilities have pursued *flexible* load interconnection options. In March 2022, for example, ERCOT implemented an interim interconnection process for large loads seeking to connect in two years or less, proposing to allow loads seeking to qualify as controllable load resources (CLRs) "to be studied as flexible and potentially interconnect more MWs" (ERCOT 2023b). More recently, ERCOT stated that "the optimal solution for grid reliability is for

4 For example, the Clean Energy Buyers Association (2024) noted, "Flexibility of co-located demand is a key asset that can enable rapid, reliable interconnection."

5 Such an arrangement is analogous to provisional interconnection service available to large generators, as defined in Section 5.9.2 of FERC's Pro Forma *Large Generator Interconnection Agreement* (LGIA).

6 MISO's market monitor representative stated, "instead of being a network firm customer, could [large flexible loads] be a non-firm, or partial non-firm [customer], and that could come with certain configuration requirements that make them truly non-firm, or partially non-firm. But, all those things are the things that could enable some loads to get on the system quicker" (FERC 2024c).

more loads to participate in economic dispatch as CLRs" (Springer 2024). Similarly, Pacific Gas and Electric (PG&E) recently introduced a Flex Connect program to allow certain loads faster access to the grid (Allsup 2024).

These options resemble interconnection services available to large generators that forgo capacity compensation, and potentially higher curtailment risk, in exchange for expedited lower-cost grid access (Norris 2023). FERC codified this approach with Energy Resource Interconnection Service (ERIS) in Order 2003 and revisited the concept during a 2024 technical workshop to explore potential improvements (Norris 2024). Some market participants have since proposed modifying ERIS to facilitate the colocation of new generators with large loads (Intersect Power 2024).

## Ratepayers Benefit from Higher System Utilization

The US electric power system is characterized by a relatively low utilization rate, often referred to as the *load factor*. The load factor is the ratio of average demand to peak demand over a given period and provides a measure of the utilization of system capacity (Cerna et al. 2023). A system with a high load factor operates closer to its peak system load for more hours throughout the year, while a system with a low load factor generally experiences demand spikes that are higher than its typical demand levels (Cerna et al. 2022). This discrepancy means that, for much of the year, a significant portion of a system's available generation and transmission infrastructure is underutilized (Cochran et al. 2015).

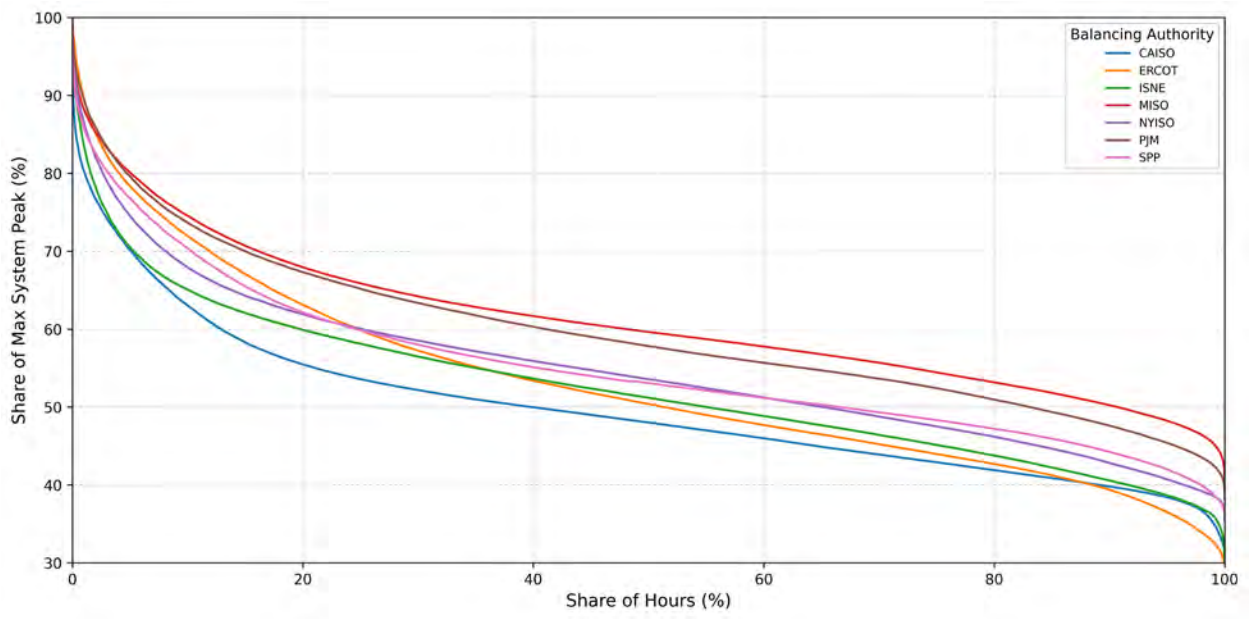
The power system is designed to handle the highest demand peaks, which in some cases may occur less than once per year, on average, due to extreme weather events. As a result, the bulk of the year sees demand levels well below that peak, leaving substantial headroom in installed capacity. Seasonal shifts add another layer of complexity: some balancing authorities may show higher load factors in summer, yet experience significantly lower utilization in winter, and vice versa.

The *load duration curve* (LDC) illustrates system utilization by ranking demand from highest to lowest over a given period. It provides a visual representation of how often certain demand levels occur, highlighting the frequency and magnitude of peak demand relative to average load. A steep LDC suggests high demand variability, with peaks significantly exceeding typical loads, while a flatter LDC indicates more consistent usage. Figure 2 presents LDCs for each US RTO/ISO based on hourly load between 2016 and 2024, standardized as a percentage of each system's maximum peak demand to allow cross-market comparisons.

A system utilization rate below 100% is expected for most large-scale infrastructure designed to withstand occasional surges in demand. Nevertheless, when the gap between average demand and peak demand is consistently large, it implies that substantial portions of the electric power system—generation assets, transmission infrastructure, and distribution networks—remain idle for much of the year (Riu et al. 2024). These assets are expensive to build and maintain, and ratepayers ultimately bear the cost.

Once the infrastructure is in place, however, there is a strong economic incentive to increase usage and spread these fixed costs over more kilowatt-hours of delivered electricity. An important consideration is therefore the potential for additional load to be added without significant new investment, provided the additional load does not raise the system's overall

## Figure 2. Load Duration Curve for US RTO/ISOs, 2016–2024




This figure is adapted from the analysis section of this paper, which contains additional detail on the data and method.

peak demand and thereby trigger system expansion.[7] When new loads are flexible enough to avoid a high coincident load factor, thereby mitigating contribution to the highest-demand hours, they fit within the existing grid's headroom.[8] By strategically timing or curtailing demand, these flexible loads can minimize their impact on peak periods. In doing so, they help existing customers by improving the overall utilization rate—thereby lowering the per-unit cost of electricity—and reduce the likelihood that expensive new peaking plants or network expansions may be needed.

In contrast, inflexible new loads that increase the system's absolute peak demand can drive substantial additional needs for generation and transmission capacity. Even a modest rise in peak demand may trigger capital investments in peaking plants, fuel supply infrastructure, and reliability enhancements. These cost implications have contributed to increasingly contentious disputes in which regulators or ratepayer advocates seek to create mechanisms to pass the costs of serving large loads directly to those loads and otherwise ensure data centers do not shift costs via longer contract commitments, billing minimums, and upfront investment (Howland 2024a; Riu et al. 2024). Some examples include:

- The **Georgia Public Service Commission (GPSC)**, citing "staggering" large load growth and the need to protect ratepayers from the costs of serving those customers, recently implemented changes to customer contract provisions if peak draw exceeds 100 MW, mandating a GPSC review and allowing the utility to seek longer contracts and minimum billing for cost recovery (GPSC 2025). This follows GPSC's approval

7 See the discussion on limitations and further analysis in the following section for additional nuance.

8 Demand charges are often based on coincident consumption (e.g., ERCOT's Four Coincident Peak charge uses the load's coincident consumption at the system's expected seasonal peak to determine an averaged demand charge that may account for >30% of a user's annual bill).

of 1.4 GW of gas capacity proposed by Georgia Power in response to load growth "approximately 17 times greater than previously forecasted" through 2030/2031, a forecast it revised upward in late 2024 (GPC 2023, 2024).

- **Ohio**, where American Electric Power issued a moratorium on data center service requests, followed by a settlement agreement with the Public Service Commission staff and consumer advocates that calls for longer contract terms, load ramping schedules, a minimum demand charge, and collateral for service from data centers exceeding 25 MW (Ohio Power Company 2024).
- **Indiana**, where 4.4 GW of interconnection requests from a "handful" of data centers represents a 157% increase in peak load for Indiana Michigan Power over the next six years. Stakeholders there have proposed "firewalling" the associated cost of service from the rest of the rate base, wherein the utility would procure a separate energy, capacity, and ancillary resource portfolio for large loads and recover that portfolio's costs from only the qualifying large loads (Inskeep 2024).
- **Illinois**, where Commonwealth Edison reported that large loads have paid 8.2% of their interconnection costs while the remaining 91.8% is socialized across general customers (ComEd 2024).

These examples underscore the significance of exploring how flexible loads can mitigate peak increases, optimize the utilization of existing infrastructure, and reduce the urgency for costly and time-consuming capacity expansions.

## Demand Response and Data Centers

*Demand response* refers to changes in electricity usage by end-use customers to provide grid services in response to economic signals, reliability events, or other conditions. Originally developed to reduce peak loads (also called *peak shaving*), demand response programs have evolved to encompass a variety of grid services, including balancing services, ancillary services, targeted deferral of grid upgrades, and even variable renewable integration (Hurley et al. 2013; Ruggles et al. 2021). Demand response is often referred to as a form of *demand-side management* or *demand flexibility* (Nethercutt 2023).

Demand response is the largest and most established form of virtual power plant (Downing et al. 2023), with 33 GW of registered capacity in wholesale RTO/ISO programs and 31 GW in retail programs as of 2023 (FERC 2024a).[9] As a share of peak demand, participation in RTO/ISO programs ranges from a high of 10.1% in MISO to a low of 1.4% in SPP. A majority of enrolled capacity in demand response programs are industrial or commercial customers, representing nearly 70% of registered capacity in retail (EIA 2024).

Following a decade of expansion, growth in demand response program participation stalled in the mid-2010s partially because of depressed capacity prices, forecasted over-capacity, and increasingly restrictive wholesale market participation rules (Hledik et al. 2019). However, the resurgence of load growth and increasing capacity prices, coupled with ongoing advancements in DERs and grid information and communication technologies (ICT) appears likely to reverse this trend.

9 RTO/ISO and retail data may overlap.

Studies of national demand response potential have identified a range of potential scenarios (Becker et al. 2024), ranging as high as 200 GW by 2030 in a 2019 study, comprising 20% of the then-forecasted system peak and yielding $15 billion in annual benefits primarily via avoided generation and transmission and distribution (T&D) capacity (Hledik et al. 2019). Notably, this research was conducted before recent load growth forecasts.

## The Participation Gap: Data Centers and Demand Response

For nearly two decades, computational loads—and data centers in particular—have been identified as a promising area for demand response. Early studies explored these capabilities, such as a two-phase Lawrence Berkeley National Laboratory study drawing on six years of research, which concluded in 2010 that "data centers, on the basis of their operational characteristics and energy use, have significant potential for demand response" (Ghatikar et al. 2010) and in 2012 that "[certain] data centers can participate in demand response programs with no impact to operations or service-level agreements" (Ghatikar et al. 2012). The 2012 study provided one of the earliest demonstrations of computational load responsiveness, finding that 10% load shed can typically occur within 6 to 15 minutes.

Despite this promise, data centers have historically exhibited low participation rates in demand response programs as a result of operational priorities and economic incentives (Basmadjian 2019; Clausen et al. 2019; Wierman et al. 2014). Data centers are designed to provide reliable, uninterrupted service and generally operate under service-level agreements (SLAs) that mandate specific performance benchmarks, including uptime, latency, and overall quality of service. Deviation from these standards can result in financial penalties and reputational harm, creating a high-stakes environment where operators are averse to operational changes that introduce uncertainty or risk (Basmadjian et al. 2018).

Compounding this challenge is the increasing prevalence of large-scale colocated data centers, which represent a significant share of the data center market (Shehabi et al. 2024). These facilities house multiple tenants, each with varying operational requirements. Coordinating demand response participation in such environments introduces layers of administrative and logistical complexity, as operators must mediate cost- and reward-sharing agreements among tenants. Further, while data centers possess significant technical capabilities, tapping these capabilities for demand response requires sophisticated planning and expertise, which some operators may not have needed to date (Silva et al. 2024).

Economic considerations have further compounded this reluctance. Implementing a demand response program requires investments in advanced energy management systems, staff training, and integration with utility platforms for which costs can be material, particularly for smaller or midsized facilities. At the same time, financial incentives provided by most demand response programs have historically been modest and insufficient to offset the expenses and opportunity costs associated with curtailed operations. For operators focused on maintaining high utilization rates and controlling costs, the economic proposition of demand response participation may be unattractive.

Existing demand response program designs may inadvertently discourage participation. Many programs were originally created with traditional industrial consumers in mind, with different incentives and operational specifications. Price-based programs may require high price variability to elicit meaningful responses, while direct control programs without sufficient guardrails may introduce unacceptable risks related to uptime and performance. The

complexity of active participation in demand response markets, including bidding processes and navigating market mechanisms, adds another layer of difficulty. Without streamlined participation structures, tailored incentives, and metrics that reflect the scale and responsiveness of data centers, many existing demand response programs may be ill-suited to the operational realities of modern data centers.

### Table 1. Key Data Center Terms

| Term | Definition |
|---|---|
| AI workload | A broad category encompassing computational tasks related to machine learning, natural language processing, generative AI, deep learning, and other AI-driven applications. |
| AI-specialized data center | Typically developed by hyperscalers, this type of facility is optimized for AI workloads and relies heavily on high-performance graphics processing units (GPUs) and advanced central processing units (CPUs) to handle intensive computing demands. |
| Computational load | A category of electrical demand primarily driven by computing and data processing activities, ranging from general-purpose computing to specialized AI model training, cryptographic processing, and high-performance computing (HPC). |
| Conventional data center | A facility that could range from a small enterprise-run server room to a large-scale cloud data center that handles diverse non-AI workloads, including file sharing, transaction processing, and application hosting. These facilities are predominantly powered by CPUs. |
| Conventional workload | A diverse array of computing tasks typically handled by CPUs, including file sharing, transaction processing, application hosting, and similar operations. |
| Cryptomine | A dedicated server farm optimized for high-throughput operations on blockchain networks, typically focused on validating and generating cryptocurrency. |
| Hyperscalers/hyperscale data centers | Large, well-capitalized cloud service providers that build hyperscale data centers to achieve scalability and high performance at multihundred megawatt scale or larger (Howland 2024b, Miller 2024). |
| Inferencing | The ongoing application of an AI model, where users prompt the model to provide responses or outputs. According to EPRI, inferencing represents 60% of an AI model's annual energy consumption (Aljbour and Wilson 2024). |
| Model training | The process of developing and training AI models by processing vast amounts of data. Model training accounts for 30–40% of annual AI power consumption and can take weeks or months to complete (Aljbour and Wilson 2024). |

## Rethinking Data Centers with AI-Driven Flexibility

Limited documentation of commercial data center participation in demand response has reinforced a perception that these facilities' demands are inherently inflexible loads. A variety of recent developments in computational load profiles, operational capabilities, and broader market conditions, however, suggest that a new phase of opportunity and necessity is emerging.

In a July 2024 memo on data center electricity demand, the SEAB recommended the Department of Energy prioritize initiatives to characterize and advance data center load flexibility, including the development of a "flexibility taxonomy and framework that explores the financial incentives and policy changes needed to drive flexible operation" (SEAB 2024). Building on these recommendations, EPRI announced a multi-year Data Center Flexible Load Initiative (DCFlex) in October 2024 with an objective "to spark change through hands-on and experiential demonstrations that showcase the full potential of data center operational flexibility and facility asset utilization," in partnership with multiple tech companies, electric utilities, and independent system operators (Walton 2024a).[10]

The central hypothesis is that the evolving computational load profiles of AI-specialized data centers facilitate operational capabilities that are more amendable to load flexibility. Unlike the many real-time processing demands typical of conventional data center workloads, such as cloud services and enterprise applications, the training of neural networks that power large language models and other machine learning algorithms is deferrable. This flexibility in timing, often referred to as *temporal flexibility*, allows for the strategic scheduling of training as well as other delay-tolerant tasks, both AI and non-AI alike. These delay-tolerant tasks are also referred to as *batch processing* and are typically not user-prompted (AWS 2025).

This temporal flexibility complements the developing interest in *spatial flexibility*, the ability to dynamically distribute workloads across one or multiple data centers in different geographic locations, optimizing resource utilization and operational efficiency. As stated by EPRI in a May 2024 report, "optimizing data center computation and geographic location to respond to electricity supply conditions, electricity carbon intensity, and other factors in addition to minimizing latency enables data centers to actively adjust their electricity consumption … some could achieve significant cost savings—as much as 15%—by optimizing computation to capitalize on lower electric rates during off-peak hours, reducing strain on the grid during high-demand periods" (EPRI 2024). For instance, having already developed a temporal workload shifting system, Google is seeking to implement spatial flexibility as well (Radovanović 2020).

In addition to temporal and spatial flexibility, other temporary load reduction methods may also enable data center flexibility. One approach is dynamic voltage and frequency scaling, which reduces server power consumption by lowering voltage or frequency at the expense of processing speed (Moons et al. 2017; Basmadjian 2019; Basmadjian and de Meer 2018). Another is server optimization, which consolidates workloads onto fewer servers while idling or shutting down underutilized ones, thereby reducing energy waste (Basmajian 2019; Chaurasia et al. 2021). These load reduction methods are driven by advances in virtual workload management, made possible by the "virtualization" of hardware (Pantazoglou et al. 2016).

10 Pointing to EPRI's new DCFlex Initiative, Michael Liebreich noted in a recent essay, "For instance, when they see how much it costs to work 24/7 at full power, perhaps data-center owners will see a benefit to providing some demand response capacity… " (Liebreich 2024).

Finally, temperature flexibility leverages the fact that cooling systems account for 30% to 40% of data center energy consumption (EPRI 2024). For instance, operators can increase cooling during midday when solar energy is abundant and reduce cooling during peak evening demand.[11] While these methods may be perceived as uneconomic due to potential impacts on performance, hardware lifespan, or SLAs, they are not intended for continuous use. Instead, they are best suited for deployment during critical hours when grid demand reduction is most valuable.

Beyond peak shaving, data centers also hold potential to participate in ancillary services, particularly those requiring rapid response, such as frequency regulation. Studies have described how data centers can dynamically adjust workloads to provide real-time support to the grid, effectively acting as "virtual spinning reserves" that help stabilize grid frequency and integrate intermittent renewable resources (McClurg et al. 2016; Al Kez et al. 2021; Wang et al. 2019). This capability extends beyond traditional demand response by providing near-instantaneous balancing resources (Zhang et al. 2022).

Three overarching market trends create further opportunities for load flexibility now than in the past. The first is constrained supply-side market conditions that raise costs and lead times for the interconnecting large inflexible loads, when speed to market is paramount for AI developers. The second is advancements in on-site generation and storage technologies that have lowered costs and expanded the availability of cleaner and more commercially viable behind-the-meter solutions, increasing their appeal to data center operators (Baumann et al. 2020). The third is the growing concentration of computational load in colocated or hyper-scale data centers—accounting for roughly 80% of the market in 2023—which is lending scale and specialization to more sophisticated data center operators. These operators, seek-ing speed to market, may be more likely to adopt flexibility in return for faster interconnec-tion (Shehabi et al. 2024; Basmadjian et al. 2018). The overarching trends underpinning this thesis are summarized in Table 2.

An important consideration for future data center load profiles is the balance between AI-specialized data centers focused on model development and those oriented toward inferencing. If fewer AI models are developed, a larger proportion of computing resources will shift toward inferencing tasks, which is delay-intolerant and variable (Riu et al. 2024). According to EPRI, training an AI model accounts for 30% of its annual footprint, compared to 60% for inferencing the same model (EPRI 2024).

In the absence of regulatory guidance, most advancements in data center flexibility to date are being driven by voluntary private-sector initiatives. Some hyperscalers and data center developers are taking steps to mitigate grid constraints by prioritizing near-term solutions for load flexibility. For example, one such company, Verrus, has established its business model around the premise that flexible data center operations offer an effective solution for growth needs (SIP 2024). Table 3 highlights additional initiatives related to facilitating or demonstrating data center flexibility.

11 Cooling demand for servers is inherently dependent on server workloads. Therefore, reducing workloads saves on cooling needs as well.

## Table 2. Trends Enabling Data Center Load Flexibility

| Category | Legacy | Future |
|---|---|---|
| Computational load profile | • Conventional servers with CPU-dominated workloads (Shehabi et al. 2024)<br>• Real-time, delay-intolerant, and unscheduled processing (e.g., cloud services, enterprise apps)<br>• Low latency critical | • AI-specialized servers with GPU or tensor processing unit (TPU)-favored workloads (Shehabi et al. 2024)<br>• Greater portion of delay-tolerant and scheduled machine learning workloads (model training, non-interactive services)<br>• Higher share of model training affords greater demand predictability<br>• Highly parallelized workloads (Shehabi et al. 2024) |
| Operational capabilities | • Minimal temporal load shifting<br>• Minimal spatial load migration<br>• High proximity to end users for latency-sensitive tasks<br>• Reliance on Tier 2 diesel generators for backup<br>• Limited utilization of on-site power resulting from pollution concerns and regulatory restrictions (Cary 2023) | • More robust and intelligent temporal workload shifting (Radovanović et al. 2022)<br>• Advanced spatial load migration and multi–data center training (D. Patel et al. 2024)<br>• Flexibility in location for model training<br>• Backup power diversified (storage, renewables, natural gas, cleaner diesel)<br>• Cleaner on-site power enables greater utilization |
| Market conditions | • Minimal electric load growth<br>• High availability of T&D network headroom<br>• Standard interconnection timelines and queue volumes<br>• Low supply chain bottlenecks for T&D equipment<br>• Low capacity prices and forecasted overcapacity<br>• High cost of clean on-site power options<br>• Small-scale “server room” model | • High electric load growth<br>• Low availability of T&D network headroom<br>• Long interconnection timelines and overloaded queues<br>• High supply chain bottlenecks for T&D equipment<br>• High capacity prices and forecasted undercapacity (Walton 2024b)<br>• Lower cost of clean on-site power options (Baranko et al. 2024)<br>• Data center operations concentrating in large-scale facilities and operators |

## Table 3. Implementations of Computational Load Flexibility

| Category | Examples |
|---|---|
| Operational flexibility | • Google deployed a "carbon-aware" temporal workload–shifting algorithm and is now seeking to develop geographic distribution capabilities (Radovanović 2020).<br>• Google data centers have participated in demand response by reducing non-urgent compute tasks during grid stress events in Oregon, Nebraska, the US Southeast, Europe, and Taiwan (Mehra and Hasegawa 2023).<br>• Enel X has supported demand response participation by data centers in North America, Ireland, Australia, South Korea, and Japan, including use of on-site batteries and generators to enable islanding within minutes (Enel X 2024).<br>• Startup companies like Emerald AI are developing software to enable large-scale demand response from data centers through recent advances in computational resource management to precisely deliver grid services while preserving acceptable quality of service for compute users |
| On-site power | • Enchanted Rock, an energy solutions provider that supported Microsoft in building a renewable natural gas plant for a data center in San Jose, CA, created a behind-the-meter solution called Bridge-to-Grid, which seeks to provide intermediate power until primary service can be switched to the utility. At that point, the on-site power transitions to flexible backup power (Enchanted Rock 2024, 2025). |
| Market design and utility programs | • ERCOT established the Large Flexible Load Task Force and began to require the registration of large, interruptible loads seeking to interconnect with ERCOT for better visibility into their energy demand over the next five years (Hodge 2024).<br>• ERCOT's demand response program shows promise for data center flexibility, with 750+ MW of data mining load registered as CLRs, which are dispatched by ERCOT within preset conditions (ERCOT 2023a).<br>• PG&E debuted Flex Connect, a pilot that provides quicker interconnection service to large loads in return for flexibility at the margin when the system is constrained (Allsup 2024, St. John 2024). |
| Cryptomining | • A company generated more revenue from its demand response participation in ERCOT than from Bitcoin mining in one month, at times accommodating a 95% load reduction during peak demands (Riot Platforms 2023). |

## ANALYSIS OF CURTAILMENT-ENABLED HEADROOM

In this section we describe the method for estimating the gigawatts of new load that could be added to existing US power system load before the total exceeds what system planers are prepared to serve, provided that load curtailment is applied as needed. This serves as a proxy for the system's ability to integrate new load, which we term *curtailment-enabled headroom*.[12] We first investigated the aggregate and seasonal load factor for each of the 22 investigated balancing authorities, which measures a system's average utilization rate. Second, we computed the curtailment-enabled headroom for different assumptions of ac-

12 SEAB proposed a similar term, *available flex capacity*, in its July 2024 report *Recommendations on Powering Artificial Intelligence and Data Center Infrastructure*.

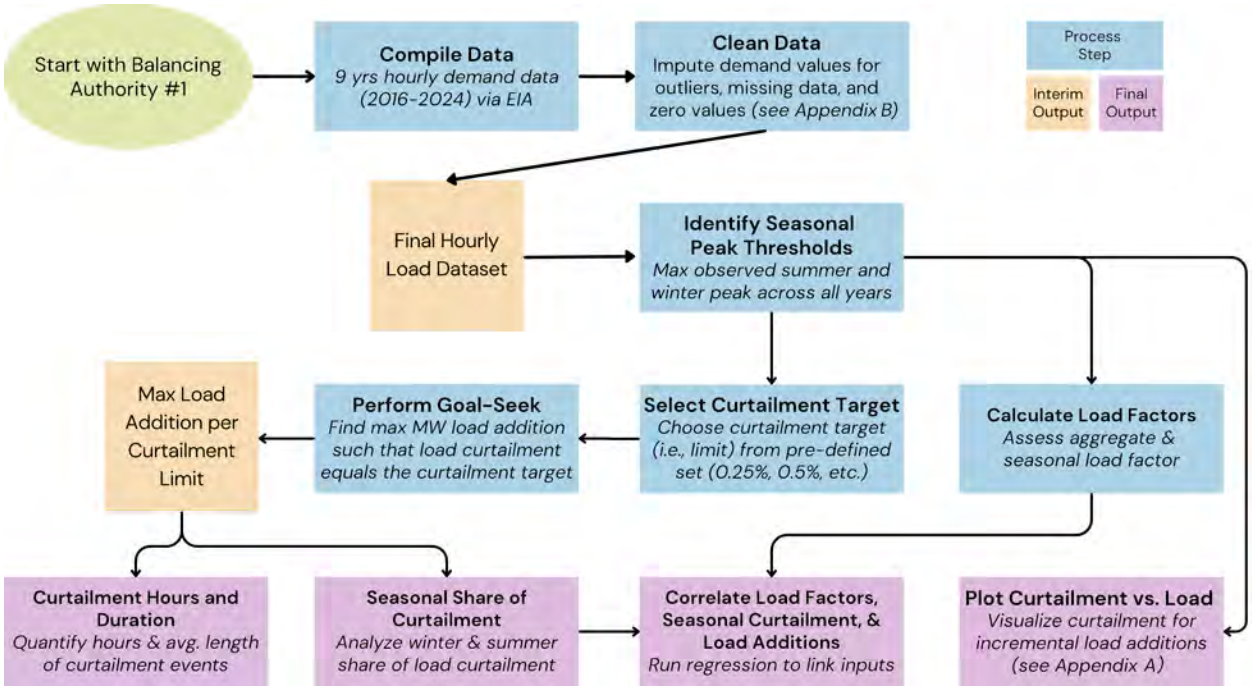
ceptable new load curtailment rates. In this context, *curtailment* refers to instances where the new load temporarily reduces its electricity draw—such as by using on-site generation resources, shifting load temporally or spatially, or otherwise reducing operations—to ensure system demand does not exceed historical peak thresholds. Third, we quantified the magnitude, duration, and seasonal concentration of the load curtailment for each balancing authority. Finally, we examined the correlation between load factor, seasonal curtailment, and max potential load additions. This process is summarized in Figure 3.

## Data and Method

### Data

We considered nine years of hourly load data aggregated for each of the 22 balancing authorities, encompassing seven RTO/ISOs,[13] eight non-RTO Southeastern BAs,[14] and seven non-RTO Western BAs.[15] Together, these balancing authorities represent 744 of the approximate 777 GW of summer peak load (95%) across the continental United States. The dataset, sourced from the EIA Hourly Load Monitor (EIA-930), contains one demand value per hour

### Figure 3. Steps for Calculating Headroom and Related Metrics




13 CAISO, ERCOT, ISO-NE, MISO, NYISO, PJM, and SPP.

14 DEC; DEP; DEF; DESC; FPL; Santee Cooper, SCP; Southern Company (SOCO); and TVA. Note the different BA codes used by EIA: DUK for DEC, CPLE for DEP, SCEG for DESC, FPC for DEF, and SC for SCP. Also note that Southern Company includes Georgia Power, Alabama Power, and Mississippi Power. A complete list of abbreviations and their definitions can be found at the end of the paper.

15 AZPS, BPA, PACE, PACW, PGE, PSCO, and SRP. Note that EIA uses the code BPAT for BPA. A complete list of abbreviations and their definitions can be found at the end of the paper.

and spans January 1, 2016, through December 31, 2024.[16] Data from 2015 were excluded because of incomplete reporting.[17] The dataset was cleaned to identify and impute values for samples with missing or outlier demand values (see details in Appendix B).

## Determining Load Additions for Curtailment Limits

An analysis was conducted to determine the maximum load addition for each balancing authority that can be integrated while staying within predefined curtailment limits applied to the new load. The load curtailment limits (0.25%, 0.5%, 1.0%, and 5.0%) were selected within the range of maximum curtailment caps for existing interruptible demand response programs.[18] The analysis focused on finding the load addition volume in megawatts that results in an average annual load curtailment rate per balancing authority that matches the specified limit. To achieve this, a goal-seek technique was used to solve for the load addition that satisfies this condition,[19] for which the mathematical expression is presented in Appendix C. The calculation assumed the new load is constant and hence increases the total system load by the same gigawatt volume hour-by-hour. To complement this analysis and visualize the relationship between load addition volume and curtailment, curtailment rates were also calculated across small incremental load additions (i.e., 0.25% of the BA's peak load).

## Load Curtailment Definition and Calculation

*Load curtailment* is defined as the megawatt-hour reduction of load required to prevent the augmented system demand (existing load + new load) from exceeding the maximum seasonal system peak threshold (e.g., see Figure 4). Curtailment was calculated hourly as the difference between the augmented demand and the seasonal peak threshold. These hourly curtailments in megawatt-hours were aggregated for all hours in a year to determine the total annual curtailment. The curtailment rate for each load increment was defined as the total annual curtailed megawatt-hours divided by the new load's maximum potential annual consumption, assuming continuous operation at full capacity.

## Peak Thresholds and Seasonal Differentiation

Balancing authorities develop resource expansion plans to support different peak loads in winter and summer. To account for variation, we defined seasonal peak thresholds for each balancing authority. Specifically, we identified the maximum summer peak and the maximum winter peak observed from 2016 to 2024 for each balancing authority.[20] These thresholds serve as the upper limits for system demand during their respective seasons, and all

16 Additional detail on EIA's hourly load data collection is available at https://www.eia.gov/electricity/gridmonitor/about.

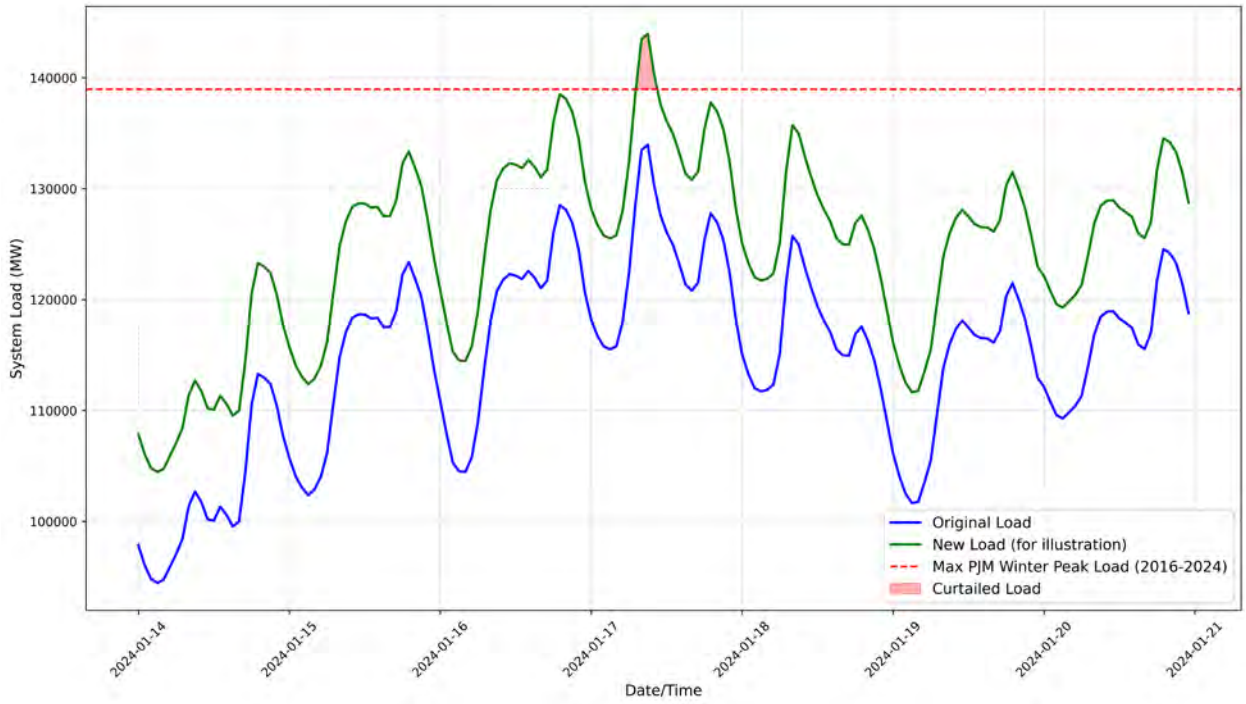
17 Fewer than half of the year's load hours were available, making the data unsuitable for inclusion.

18 For example, PG&E's and Southern California Edison's Base Interruptible Programs limit annual interruption for registered customers to a maximum of 180 hours (2.0% of all annual hours) or 10 events per month.

19 The goal-seek approach was implemented using Python's scipy.optimize.root_scalar function from the SciPy library. This tool is designed for solving one-dimensional root-finding problems, where the goal is to determine the input value that satisfies a specified equation within a defined range.

20 To identify the max seasonal peak load, summer was defined as June–August, while winter encompassed December–February. In a few cases, the BA's seasonal peak occurred within one month of these periods (AZPS winter, FPL winter, CAISO summer, CAISO winter), which were used as their max seasonal peak. To account for potential (albeit less likely) curtailment in shoulder months, the applicable summer peak was applied to April–May and September–October and the winter peak to November and March.

## Figure 4. Illustrative Load Flexibility in PJM



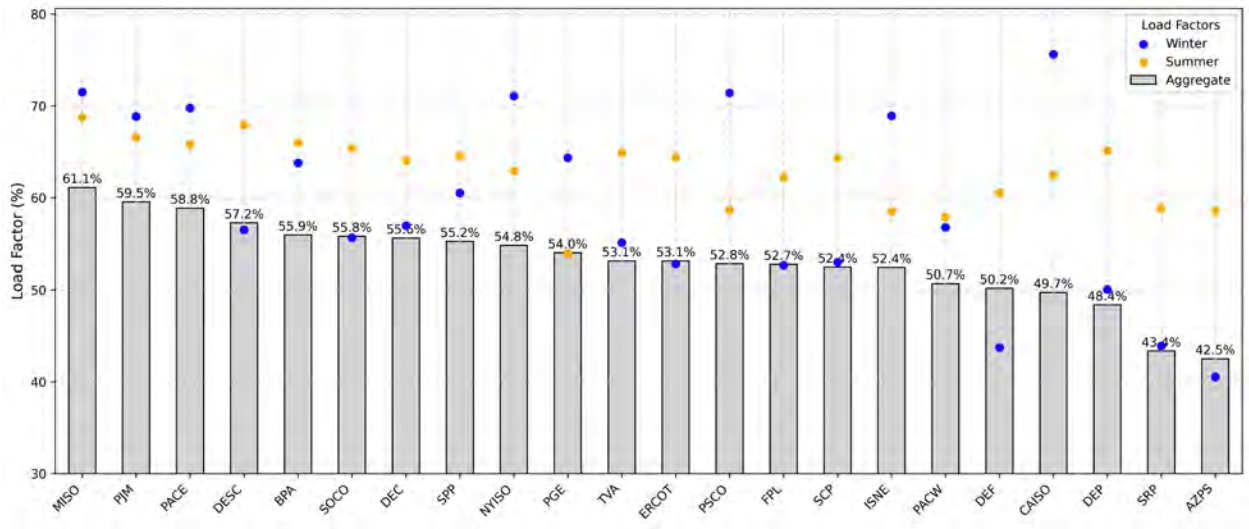

megawatt-hours that exceeded these thresholds was counted as curtailed energy. This seasonal differentiation captures the distinct demand characteristics of regions dominated by cooling loads (summer peaks) versus heating loads (winter peaks).

### Year-by-Year Curtailment Analysis

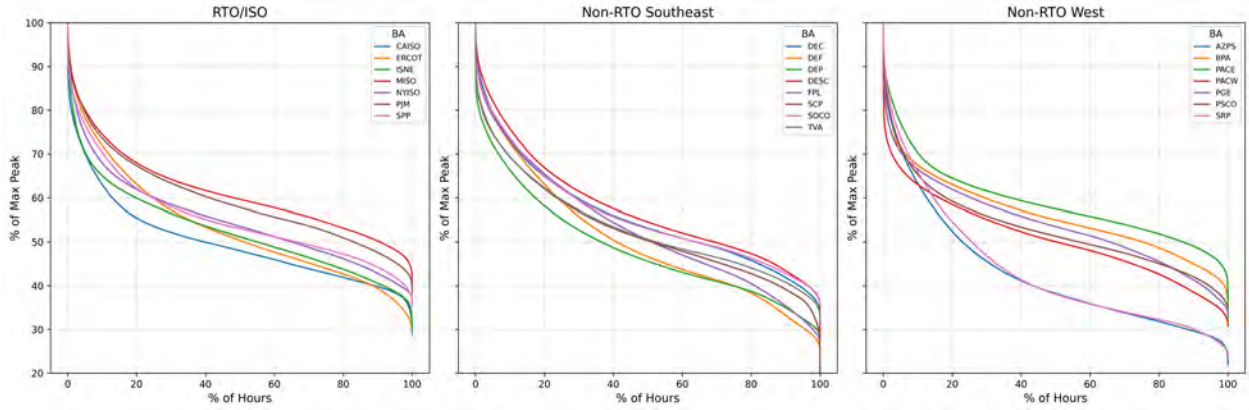
Curtailment was analyzed independently for each year from 2016 to 2024. This year-by-year approach captures temporal variability in demand patterns, including the effects of extreme weather events and economic conditions. For each year, curtailment volumes were calculated across all load addition increments, resulting in a list of annual curtailment rates corresponding to each load increment. To synthesize results across years, we calculated the average curtailment rate for each load addition increment by averaging annual curtailment rates over the nine years. This averaging process smooths out year-specific anomalies and provides an estimate of the typical system response to additional load. This analysis was also used to calculate the average number of hours of curtailment for each curtailment limit and the seasonal allocation of curtailed generation.[21] We also assessed the magnitude of load curtailment required during these hours as a share of the new load's maximum potential draw to calculate the number of hours when 90%, 75%, and 50% or more of the load would still be available.

21 Consistent with the curtailment analysis, summer was defined as June–August and winter as December–February. For BAs located on the Pacific coast (BPA, CAISO, PGE, PACE, PACW), November was counted as winter given the region's unique seasonal load profile.

## Figure 5. Load Factor by Balancing Authority and Season, 2016–2024




## Figure 6. Load Duration Curves by Balancing Authority, 2016–2024




# Results

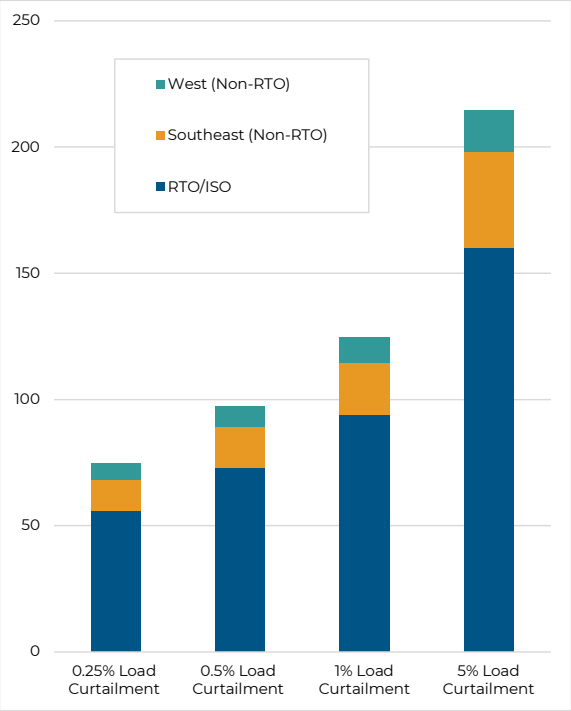
## Load Factor

In examining data for 22 balancing authorities, we found that aggregate load factors ranged between 43% to 61% (Figures 5 and 6), with an average and median value of 53%. The BAs with the lowest aggregate load factors were those in the desert southwest, Arizona Public Service Company (AZPS) and Salt River Project Agricultural Improvement and Power District (SRP). In terms of seasonal load factor, defined here as the average seasonal load as a share of seasonal maximum load (i.e., not as a share of the maximum all-time system load), winter load factors were notably lower than summer. The average and median winter load factor was 59% and 57% respectively, compared to 63% and 64% for summer. A majority of the balancing authorities had higher summer load factors (14) than winter (8).

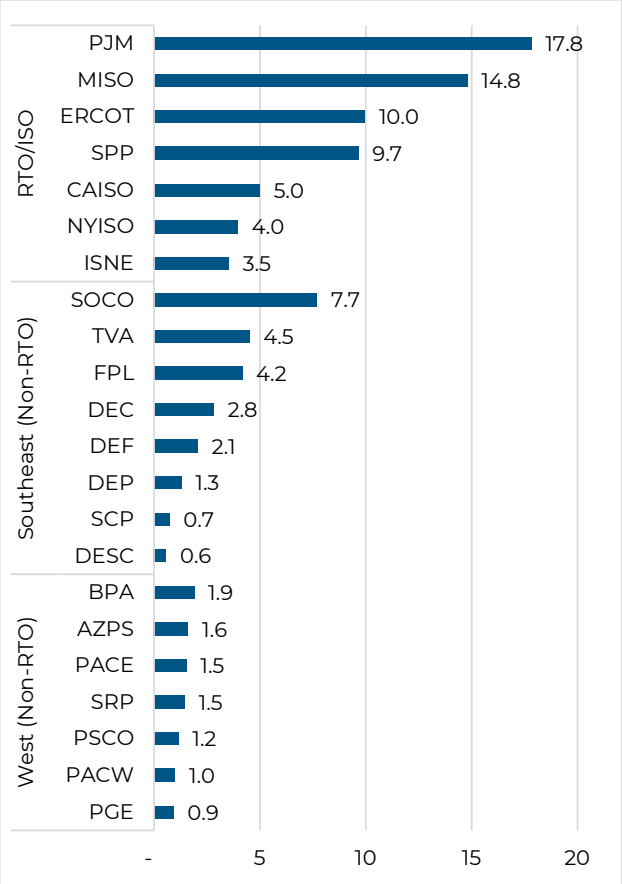
## Headroom Volume

Results show that the headroom across the 22 analyzed balancing authorities is between 76 to 215 GW, depending on the applicable load curtailment limit. This means that 76 to 215 GW of load could be added to the US power system and yet the total cumulative load would remain below the historical peak load, except for a limited number of hours per year

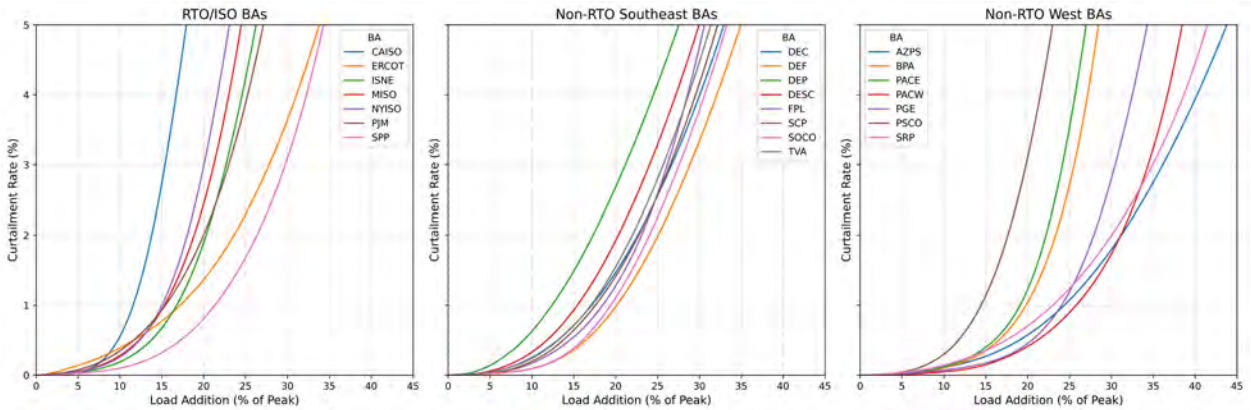
## Figure 7. Headroom Enabled by Load Curtailment Thresholds, GW




## Figure 8. Headroom Enabled by 0.5% Load Curtailment by Balancing Authority, GW




## Figure 9. Load Curtailment Rate Due to Load Addition, % of System Peak



when the new load would be unserved. Specifically, 76 GW of headroom is available at an expected load curtailment rate of 0.25% (i.e., if 0.25% of the maximum potential annual energy consumption of the new load is curtailed during the highest load hours, or 1,643 out of 657,000 GWh). This headroom increases to 98 GW at 0.5% curtailment, 126 GW at 1.0% curtailment, and 215 GW at 5.0% curtailment (Figure 7). Headroom varies by balancing authority (Figure 8), including as a share of system peak (Figure 9). The five balancing authorities with the highest potential volume at 0.5% annual curtailment are PJM at 18 GW, MISO at 15 GW, ERCOT at 10 GW, SPP at 10 GW, and Southern Company at 8 GW. Detailed plots for each balancing authority, including results for each year, can be found in Appendix A.

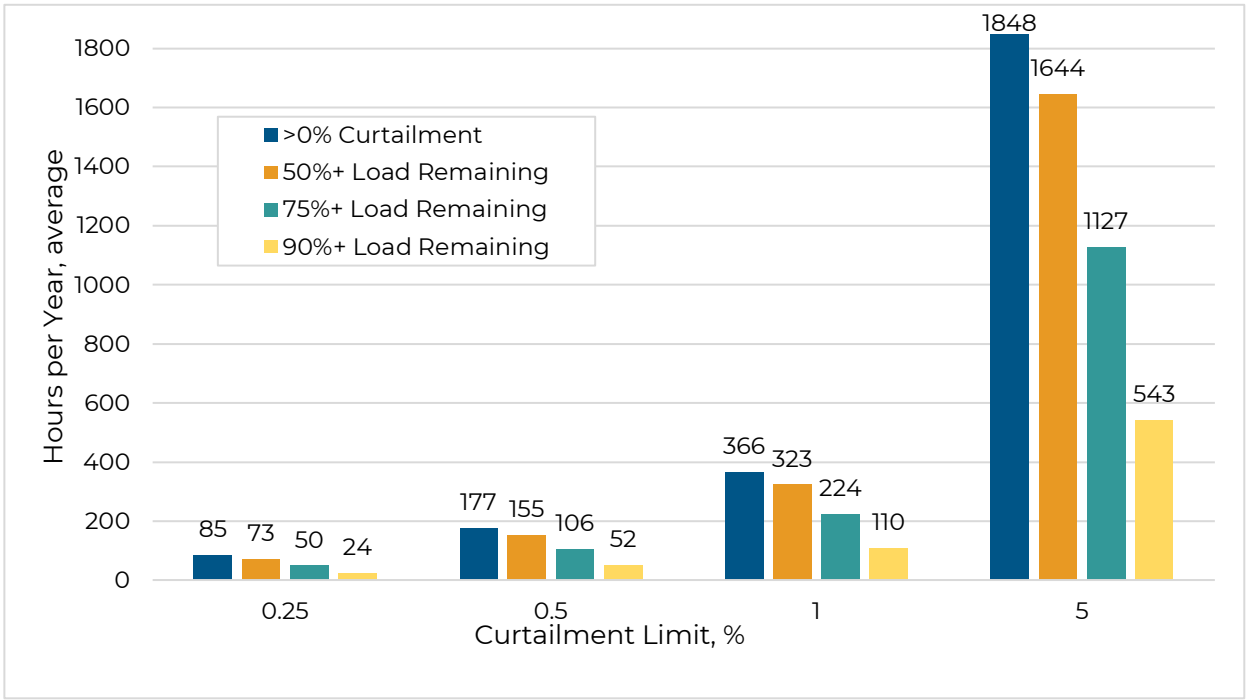
## Curtailment Hours

A large majority of curtailment hours retain most of the new load. Most hours during which load reduction is required entail a curtailment rate below 50% of the new load. Across all 22 BAs, the average required load curtailment times are 85 hours under the 0.25% curtailment rate (~1% of the hours in a year), 177 hours under the 0.5% curtailment rate, 366 hours under the 1.0% curtailment rate, and 1,848 hours under the 5.0% curtailment rate (i.e., ~21% of the hours). On average, 88% of these hours retain at least 50% of the new load (i.e., less than 50% curtailment of the load is required), 60% of the hours retain at least 75% of the load, and 29% retain at least 90% of the load (see Figure 10).

## Curtailment Duration

The analysis calculated the average hourly duration of curtailment events (i.e., the length of time the new load is curtailed during curtailment events). All hours in which any curtailment occurred were included, regardless of magnitude. The results for each balancing authority and curtailment limit are presented in Figure 11. The average duration across BAs was 1.7 hours for the 0.25% limit, 2.1 hours for the 0.5% limit, 2.5 hours for the 1.0% limit, and 4.5 hours for the 5.0% limit.

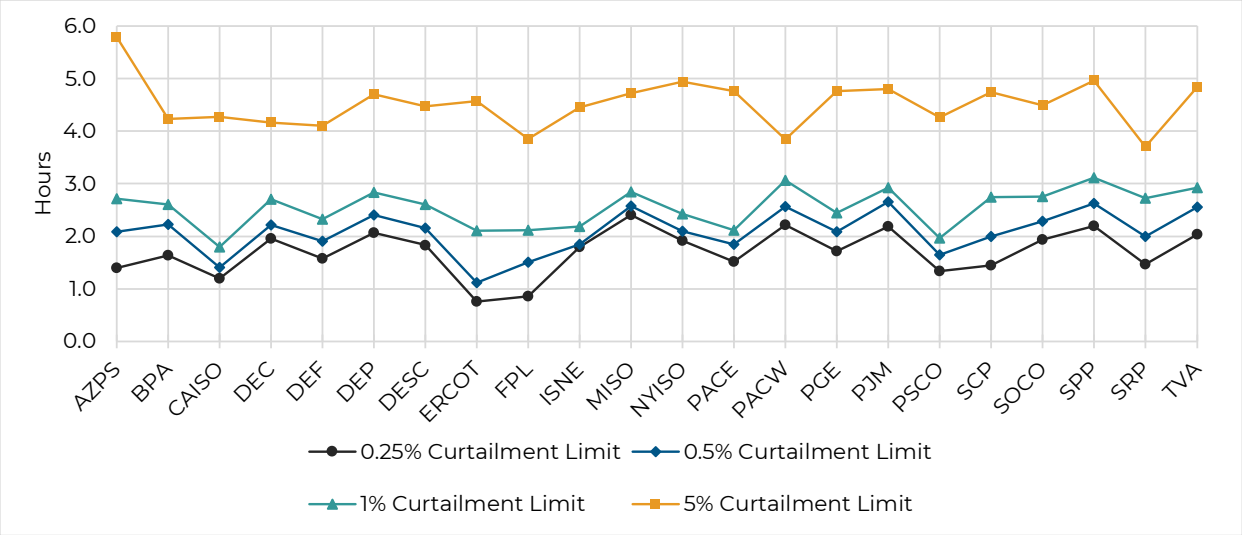
### Figure 10. Hours of Curtailment by Load Curtailment Limit



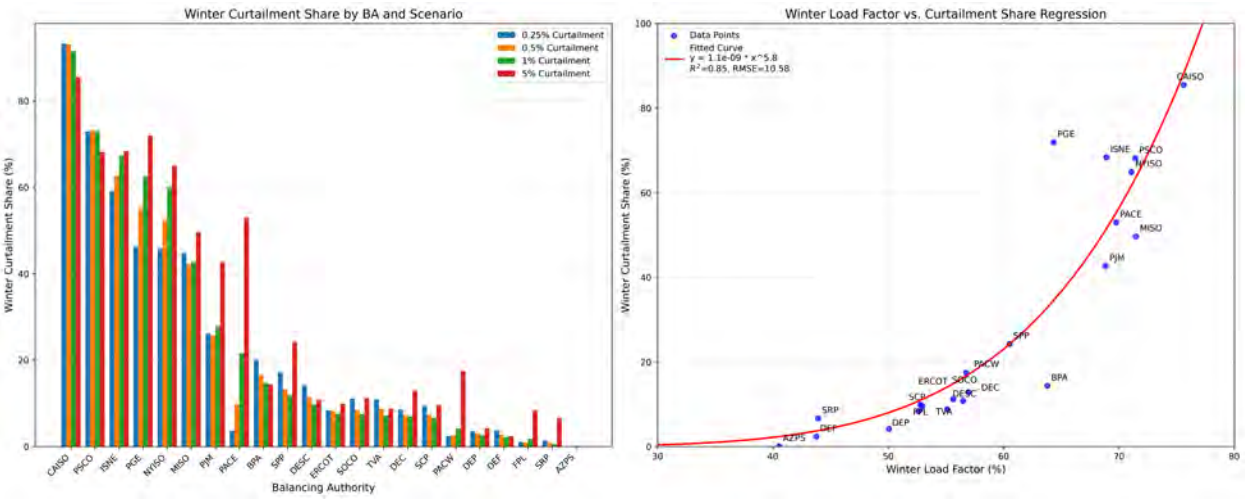
## Seasonal Concentration of Curtailment

The analysis reveals significant variation in the seasonal concentration of curtailment hours across balancing authorities. The winter-summer split ranged from 92% to 1% for CAISO (California Independent System Operator), where curtailment is heavily winter-concentrated, to 0.2% to 92% for AZPS,[22] which exhibited a heavily summer-concentrated curtailment profile (Figure 12a).[23]

### Figure 11. Average Curtailment Duration by Balancing Authority and Curtailment Limit, Hours




### Figure 12. Seasonal Curtailment Analysis




(a) (b)

22 Note the remainder of the curtailment occurred in these BAs in shoulder months (i.e., not summer, not winter).

23 These values correspond to the seasonal curtailment concentration for the 1% curtailment limit.

A key observation is the strong correlation between the winter load factor (system utilization during winter months) and the seasonal allocation of curtailment hours (Figure 12b). BAs with lower winter load factors—indicating reduced system utilization during winter—tend to have greater capacity to accommodate additional load in winter while experiencing a dispro-portionately higher share of curtailment during summer months. This trend is particularly pronounced in balancing authorities located in the Sun Belt region, resulting in a lower win-ter concentration of curtailment hours.

While most BAs exhibited relatively stable seasonal curtailment shares across increasing load addition thresholds, some demonstrated notable shifts in seasonal allocation as load additions increased (e.g., PACW, FPL, NYISO, ISO-NE, PACE, PGE). These shifts highlight the dynamic interplay between system demand patterns and the incremental addition of new load.

Figure 12a illustrates this variability, showcasing the relationship between winter load factor and winter curtailment share across curtailment scenarios.[24]

## Discussion

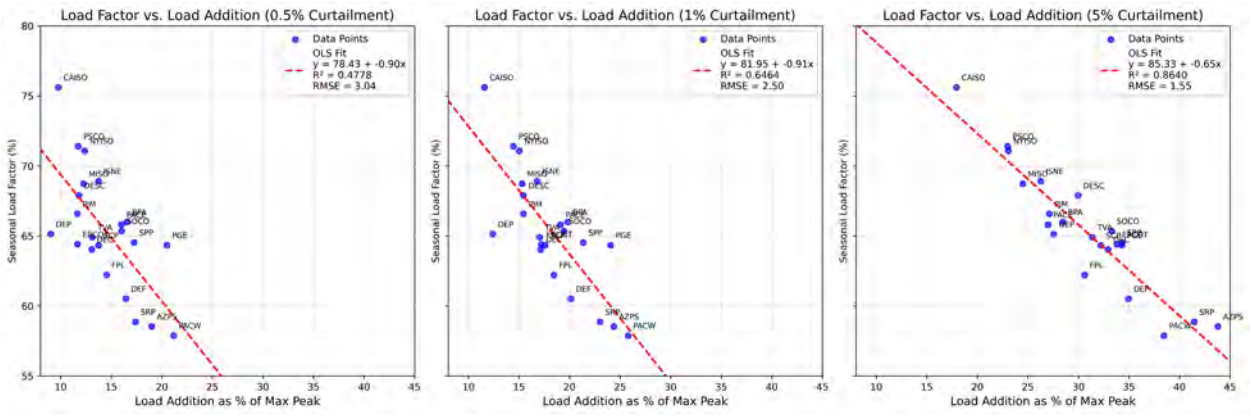
The results highlight that the significant headroom in US power systems—stemming from their by-design low load factors—could be tapped to enable the integration of substantial load additions with relatively low rates of load curtailment. They also underscore substantial variation in flexibility across balancing authorities, driven by differences in seasonal and aggregate load patterns. This variation suggests that seasonal load factors may be strongly linked to how much additional load a balancing authority can integrate without requiring high curtailment rates.

To explore this relationship, we analyzed system load factors in relation to the additional load that each balancing authority could accommodate while limiting the load curtailment rate to 0.5%, 1.0%, and 5.0% (i.e., the load curtailment limit). To allow for meaningful comparison across BAs, the additional load was standardized as a percentage of the BA's historical peak load. To account for whether a balancing authority's curtailment was concentrated in the summer or winter, the seasonal load factor was selected corresponding to the season with the highest share of curtailment.

The analysis revealed that BAs with higher seasonal load factors tended to have less headroom for the load curtailment limits examined (Figure 13). In simpler terms, systems with higher utilization during their busiest season had less power generation capacity planned to be available that could serve new load without hitting curtailment limits. For example, CAISO, with a seasonal load factor of 76%, could accommodate less additional load compared to PacifiCorp West (PACW) and AZPS, which exhibited lower seasonal load factors and supported larger load additions as a share of peak system load. This relationship grew in statistical significance as the load curtailment limit increased, yielding an $R^2$ value of 0.48 and an RMSE of 3.04 at the 0.5% curtailment limit, and an $R^2$ value of 0.86 and an RMSE of 1.55 at the 5% curtailment limit (i.e., 86% of the variation in load addition capacity across balancing authorities can be explained by differences in load factor at a curtailment limit of 5.0%).

24 Note in Figure 12b that a high-degree polynomial function captures the nonlinear growth in the area under the load curve as curtailed load exceeds a fixed peak threshold. This fit generally aligns with expectations, demonstrating that higher-degree terms are necessary to capture the relationship between load factor and curtailed load.

## Figure 13. Load Factor Versus Max Load Addition as Share of Peak Load




These findings emphasize the importance of load factor as a predictor of curtailment-enabled headroom. BAs with more uneven peak seasonal demand—characterized by relatively low system utilization in winter or summer—tend to have greater capacity to integrate new loads with limited curtailment. Conversely, systems with more consistent demand across the winter and summer face tighter limits, as their capacity to absorb additional load is already constrained by elevated baseline usage.

## Limitations

This analysis provides a first-order assessment of power generation capacity available for serving new curtailable loads, and hence is an exploration of the market potential for large-scale demand response. The primary focus of the analysis is to ensure that total demand, subject to curtailment limits for new load, stays below the system peak for which system planners have prepared. Other considerations important for planning—such as ensuring adequate transmission capacity, ramping capability, and ramp-feasible reserves, among others—are beyond the scope of this study and therefore the results cannot be taken as an accurate estimate of the load that can be added to the system. Additionally, the analysis assumes the new loads do not change current demand patterns but rather shift the existing demand curves upward, and a more precise assessment of the potential for integration of new loads would require detailed characterization of the temporal patterns of the load. There is significant variation in how system operators forecast and plan for system peaks, accounting for potential demand response, and as a result there will be differences in the methods used to estimate potential to accommodate new load. Despite these limitations, the results presented here signal a vast potential that, even if overstated, warrants further research.

On the other hand, some aspects of this study may have contributed to an underestimation of available headroom. First, the analysis assumes that each BA's maximum servable load in the winter and summer is equivalent to the BA's highest realized seasonal peak demand based on the available historical data. However, the available generation capacity in each balancing authority should materially exceed this volume when accounting for the installed reserve margin. In other words, system operators have already planned their systems to accommodate load volume that exceeds their highest realized peak. Second, the analysis removed outlier demand values in some BAs to avoid using unreasonably high maximum peak thresholds, which would understate the curtailment rates. However, if some of the removed outliers properly represent a level of system load that the system is prepared to serve reliably,

this analysis may have understated the curtailment-enabled headroom. Third, the analysis assumed all new load is constant and hence increases the total system load by the same gigawatt hour-by-hour, which would tend to overstate the absolute level of required gigawatt hour curtailment for a load that is not constant.

## Future Analysis

Enhancing this analysis to more accurately assess the capacity to integrate large curtailable load would require addressing the following considerations:

### Network Constraints

This analysis does not account for network constraints, which would require a power flow simulation to evaluate the ability of the transmission system to accommodate additional load under various conditions. As such, the results should not be interpreted as an indication that the identified load volumes could be interconnected and served without any expansions in network capacity. While the existing systems are planned to reliably serve their peak loads, this planning is based on the current load topology and the spatial distribution of generation and demand across the transmission network. A large new load could avoid exceeding aggregate peak system demand by employing flexibility, yet still cause localized grid overloads as a result of insufficient transmission capacity in specific areas. Such overloads could necessitate network upgrades, including the expansion of transmission lines, substations, or other grid infrastructure. Alternatively, in the absence of network upgrades, localized congestion could be addressed through the addition of nearby generation capacity, potentially limiting the flexibility and economic benefits of the new load. These factors underscore the importance of incorporating network-level analyses to fully understand the operational implications of large flexible load additions.

### Intertemporal Constraints

This analysis does not account for intertemporal constraints related to load and generator operations. For load operations, response times affect system operations and management of operational reserves. Faster response times from flexible loads could alleviate system stress more effectively during peak demand periods, potentially reducing the reliance on reserve capacity. Conversely, slower response times may require additional reserves to bridge the gap between the onset of system imbalances and the load's eventual response. Moreover, the rapid ramp-down of large flexible loads could lead to localized stability or voltage issues, particularly in regions with weaker grid infrastructure. These effects may necessitate more localized network analyses to evaluate stability risks and operational impacts. On the generation side, intertemporal constraints such as ramping limits, minimum up and down times, and startup times can affect the system's ability to integrate fast-response demand. For instance, ramping constraints may restrict how quickly generators can adjust output to align with the curtailment of flexible loads, while minimum uptime and downtime requirements can limit generator flexibility.

### Loss of Load Expectation

Peak load is a widely used proxy for resource adequacy and offers a reasonable indicative metric for high-level planning analyses. However, a more granular assessment would incorporate periods with the highest loss of load expectation (LOLE), which represent the times when the system is most likely to experience supply shortfalls. Historically, LOLE periods have aligned closely with peak load periods, making peak load a convenient and broadly

applicable metric. However, in markets with increasing renewable energy penetration, LOLE periods are beginning to shift away from traditional peak load periods. This shift is driven by the variability and timing of renewable generation, particularly solar and wind, which can alter the temporal distribution of system stress. As a result, analyses focused solely on peak load may understate or misrepresent the operational challenges associated with integrating large new loads into these evolving systems.

## CONCLUSION

This study highlights extensive potential for leveraging large load flexibility to address the challenges posed by rapid load growth in the US power system. By estimating the curtailment-enabled headroom across balancing authorities, the analysis demonstrates that existing system capacity—intentionally designed to accommodate the extreme swings of peak demand—could accommodate significant new load additions with relatively modest curtailment, as measured by the average number, magnitude, and duration of curtailment hours.

The findings further emphasize the relationship between load factors and headroom availability. Balancing authorities with lower seasonal load factors exhibit greater capacity to integrate flexible loads, highlighting the importance of regional load patterns in determining system-level opportunities. These results suggest that load flexibility can play a significant role in improving system utilization, mitigating the need for costly infrastructure expansion and complementing supply-side investments to support load growth and decarbonization objectives.

This analysis provides a first-order assessment of market potential, with estimates that can be refined through further evaluation. In particular, network constraints, intertemporal operational dynamics, and shifts in loss-of-load expectation periods represent opportunities for future analyses that can offer a deeper understanding of the practical and operational implications of integrating large flexible loads.

In conclusion, the integration of flexible loads offers a promising, near-term strategy for addressing structural transformations in the US electric power system. By utilizing existing system headroom, regulators and market participants can expedite the accommodation of new loads, optimize resource utilization, and support the broader goals of reliability, affordability, and sustainability.

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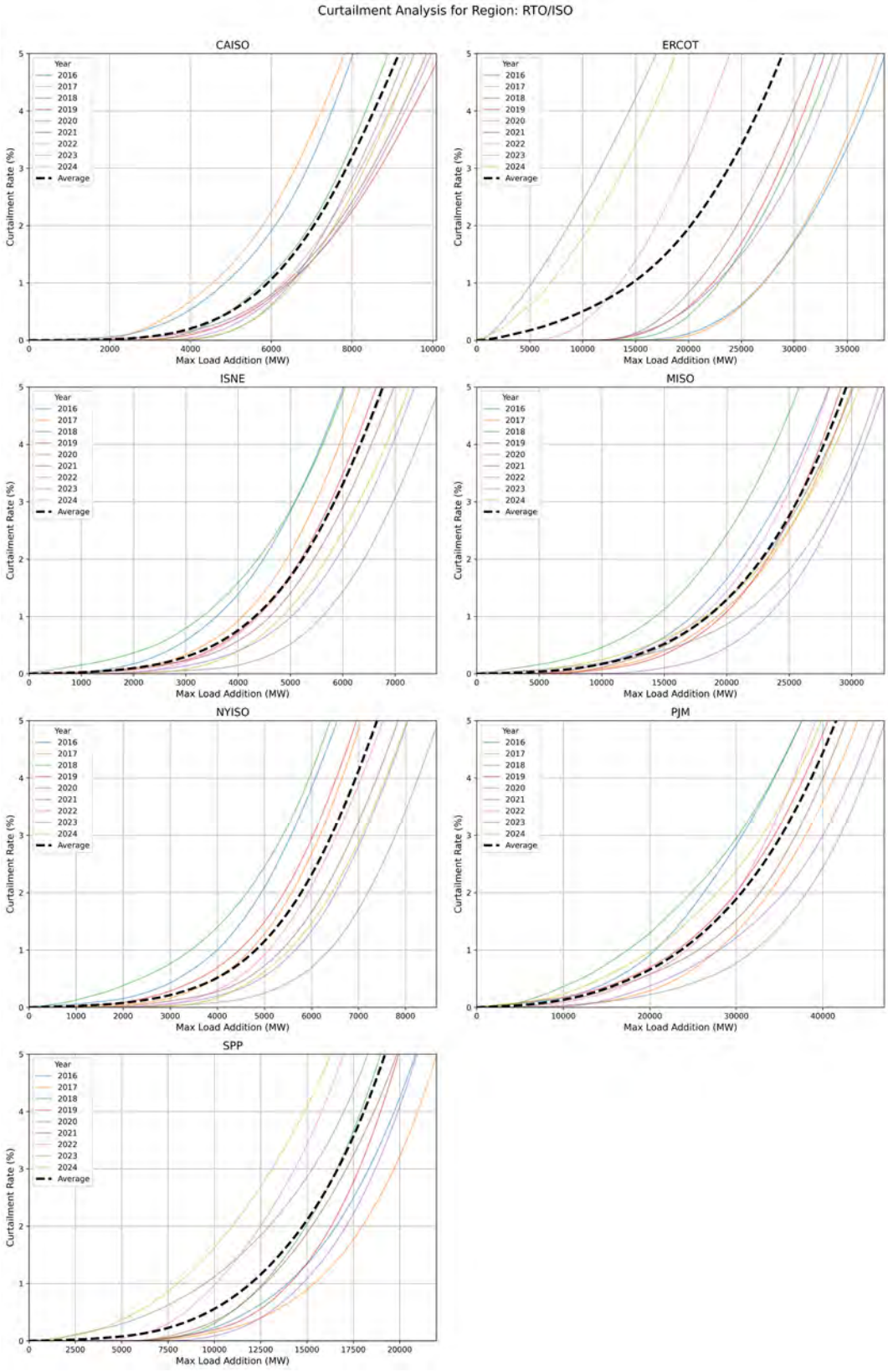
## ABBREVIATIONS

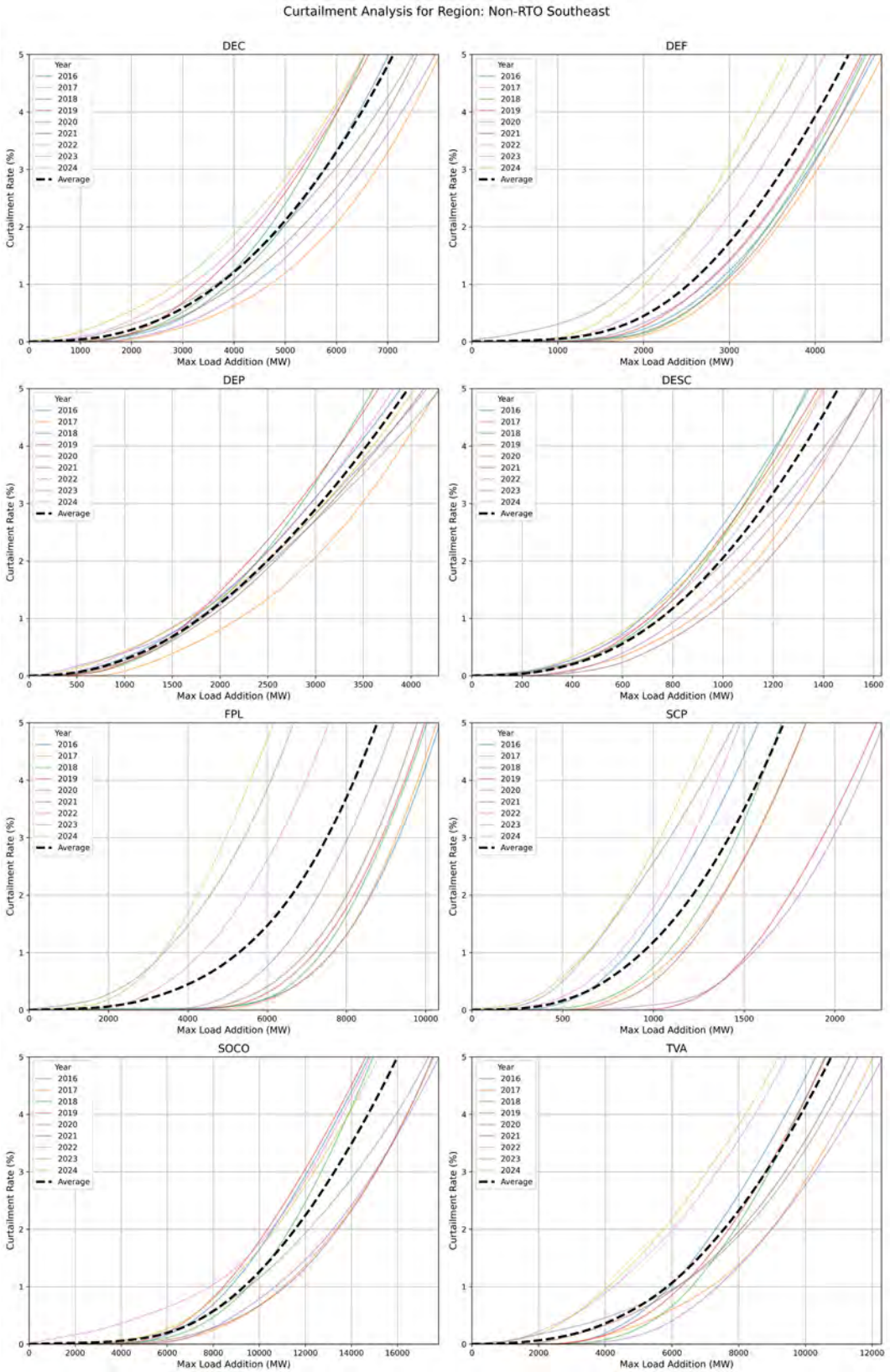
| | |
|---|---|
| AI | Artificial intelligence |
| AZPS | Arizona Public Service Company |
| BA | balancing authority |
| BPA | Bonneville Power Administration |
| CAGR | compound annual growth rate |
| CAISO | California Independent System Operator |
| CLRs | controllable load resources |
| CPUs | central processing units |
| DEC | Duke Energy Carolinas |
| DEF | Duke Energy Florida |
| DEP | Duke Energy Progress East |
| DERs | distributed energy resources |
| DESC | Dominion Energy South Carolina |
| EIA | Energy Information Administration |
| EPRI | Electrical Power Research Institute |
| ERCOT | Electric Reliability Council of Texas |
| ERIS | Energy Resource Interconnection Service |
| FERC | Federal Energy Regulatory Commission's |
| FPL | Florida Power & Light |
| GPUs | graphics processing units |
| ICT | information, and communication technology |
| ISO-NE | ISO New England |
| LGIA | Large Generator Interconnection Agreement |
| LOLE | loss of load expectation |
| MISO | Midcontinent Independent System Operator |
| NYISO | New York Independent System Operator |
| PACE | PacifiCorp East |
| PACW | PacifiCorp West |
| PG&E | Pacific Gas and Electric |
| PGE | Portland General Electric Company |
| PJM | PJM Interconnection |
| PSCO | Public Service Company of Colorado |
| RMSE | Root mean square error |
| RTO/ISO | Regional transmission organization/independent system operator |
| SCP | Santee Cooper, South Carolina Public Service Authority |
| SEAB | Secretary of Energy Advisory Board |
| SLAs | service-level agreements |
| SOCO | Southern Company |
| SPP | Southwest Power Pool |
| SRP | Salt River Project Agricultural Improvement and Power District |
| TPU | tensor processing unit |
| TVA | Tennessee Valley Authority |

# APPENDIX A: CURTAILMENT-ENABLED HEADROOM PER BALANCING AUTHORITY

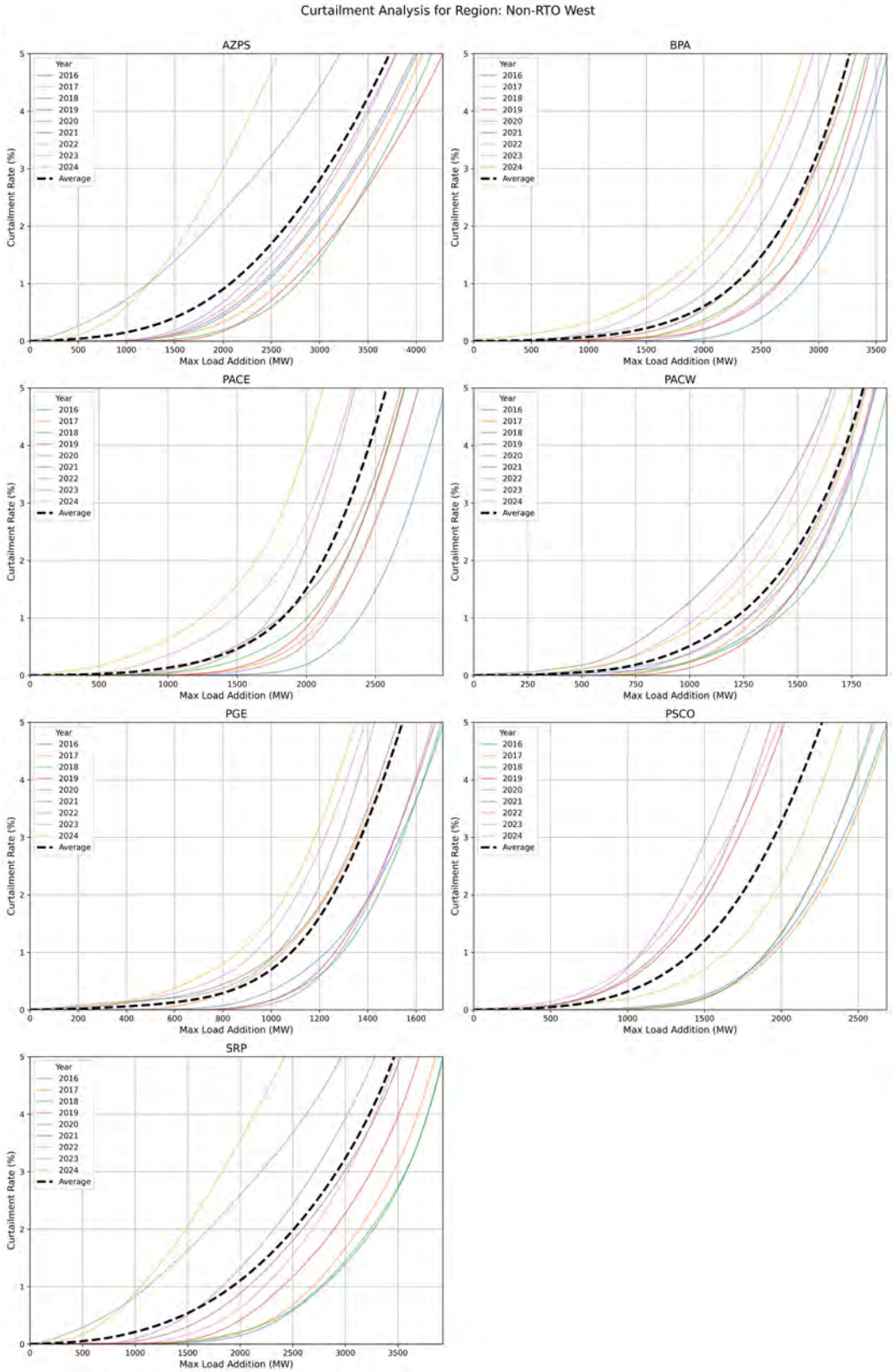
## Figure A.1. Curtailment Rate Versus Load Addition by RTO/ISO, MW



## Figure A.2. Curtailment Rate Versus Load Addition by Non-RTO Southeastern Balancing Authority, MW



## Figure A.3. Curtailment Rate Versus Load Addition by Non-RTO Western Balancing Authority, MW



## APPENDIX B: DATA CLEANING SUMMARY

The data cleaning process attempted to improve the accuracy of nine years of hourly load data across the 22 balancing authorities, including the following steps:

1. Data normalization
    - **Dates:** Date-time formats were verified to be uniform.
    - **Demand data:** Where the balancing authority had an "Adjusted demand" value for a given hour, this value was used, otherwise its "Demand" value was used. The final selected values were saved as "Demand" and a log was kept.
    - **BA labels:** Labels were mapped to align with widely used acronyms, including:
        - CPLE → DEP
        - DUK → DEC
        - SC → SCP
        - SWPP → SPP
        - SCEG → DESC
        - FPC → DEF
        - CISO → CAISO
        - BPAT → BPA
        - NYIS → NYISO
        - ERCO → ERCOT
2. Identifying and handling outliers
    - **Missing and zero values:** Filled using linear interpolation between adjacent data points to maintain temporal consistency.
    - **Low outliers:** Demand values below a predefined cutoff threshold (such as 0 or extremely low values inconsistent with historical data) were flagged. Imputation for flagged low outliers involved identifying the closest non-outlier value within the same balancing authority and time period and replacing the flagged value.
    - **Spikes:** Sudden demand spikes that deviated significantly from historical patterns were flagged. Corrections were applied based on nearby, consistent data.
    - **Erroneous peaks:** Specific known instances of demand peaks that are outliers (e.g., caused by reporting errors) are explicitly corrected or replaced with average values from adjacent time periods.
3. **Data validation**:
    - Seasonal and annual peak loads, load factors, and other summary statistics were computed and inspected to ensure no unexpected results. Max peaks were compared to forecasted peaks collected by FERC to ensure none were out of range.
    - Logs summarizing corrections, including the number of spikes or outliers addressed for each balancing authority, were saved as additional documentation.

## APPENDIX C: CURTAILMENT GOAL-SEEK FUNCTION

Mathematically, the function can be expressed as

$$\frac{1}{N}\sum_{y=1}^{N}\left(\frac{Curtailment_y(L)}{L \cdot 8{,}760}\cdot 100\right) = CurtailLimit$$

where

| | | |
|---|---|---|
| $L$ | = | load addition in MW (constant load addition for all hours) |
| $N$ | = | total number of years in the analysis (2016–2024) |
| $Curtailment_y(L)$ | = | curtailed MWh for year $y$ at load addition $L$ |
| $L \cdot 8{,}760$ | = | maximum potential energy consumption of the new load operating continuously at full capacity |
| $CurtailLimit$ | = | predefined curtailment limit (e.g., 0.25%, 0.5%, 1.0%, or 5.0%). |

For each hour $t$ in year $y$, the curtailment is defined as

$$Curtailment_t(L) = \max(0, Demand_t + L - Threshold_t)$$

where

| | | |
|---|---|---|
| $L$ | = | load addition being evaluated in MW |
| $Demand_t$ | = | system demand at hour $t$ in MW |
| $Threshold_t$ | = | seasonal peak threshold applicable for hour $t$ in MW (i.e., the maximum winter or summer peak across all years) |

These hourly curtailments are aggregated to find the total annual curtailment

$$Curtailment_y(L) = \sum_{t \in T_y} Curtailment_t(L)$$

where

| | | |
|---|---|---|
| $T_y$ | = | all hours in year $y$. |

Replacing $Curtailment_y(L)$ in the original formula, the integrated formula becomes

$$\frac{1}{N}\sum_{y=1}^{N}\left(\frac{\sum_{t \in T_y}\max(0, Demand_t + L - Threshold_t)}{L \cdot 8{,}760} * 100\right) = CurtailLimit$$

BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

| | |
|---|---|
| Federal Power Act Section 202(c) | ) |
| Emergency Order: Tri-State | ) |
| Generation and Transmission | ) |
| Association, Platte River Power | ) |
| Authority, Salt River Project, | ) |
| PacifiCorp, and Xcel Energy | ) |

Exhibit to
Motion to Intervene and Request for Rehearing and Stay of
Public Interest Organizations

Exhibit 2-44:
RMI Analysis of Coal Plants' Threats to Reliability





# Reality Check: We Have What's Needed to Reliably Power the Data Center Boom, and It's Not Coal Plants

**A range of clean, resilient solutions can help us meet the electrical needs of our growing digital economy while saving Americans money.**

**August 12, 2025**

**By Gabriella Tosado, Ashtin Massie, Joe Daniel**

After decades of relatively flat electricity demand, the US power sector is expecting demand to grow due, in large part, to new data centers. These energy-intensive facilities are reshaping the grid, with some utilities now projecting over 20 percent load growth by 2035. In places like Virginia, which constitutes 13 percent of all reported data center capacity globally and 25 percent of the data center capacity in the United States, data centers already account for over a quarter of some utilities' total electric demand, and their footprint is only growing.

## The myth

Utilities are struggling to maintain accurate forecasts and identify resources that can meet this growth. There is a high-profile effort to keep coal plants that are set to retire online and run them at unprecedented levels, ostensibly for reasons of reliability. But the truth is, coal-fired power plants, far from being a reliable backbone for this new era of electricity demand, are a brittle, outmoded technology that threatens to undermine the very grid resilience they're being proposed to protect.

> Coal-fired power plants, far from being a reliable backbone for this new era of electricity demand, are a brittle, outmoded technology that threatens to undermine the very grid resilience they're being proposed to protect.

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## Reality #1: Aging coal plants are failing to consistently deliver under stress

Coal plants face a fundamental constraint: they are aging and increasingly unreliable. Most of the coal fleet was built in the 1970s and 1980s, and years of wear and tear have led to a rise in unplanned outages. In many cases the sheer cost to maintain and modernize these plants did not make sense with the availability of more reliable and affordable alternatives – and that's still the case.

According to the Energy Systems Integration Group (ESIG) *Ensuring Efficient Reliability* report, a coal plant's capacity accreditation, or the amount of time it can contribute to peak demand, is only 83 percent when adjusted for real-world performance. PJM also has capacity accreditation of coal plants at 83 percent and some plants fare even worse. Gridlab's reliability study found Colstrip, a large regional coal plant in Montana, operating with a capacity accreditation of only 54 percent – meaning it's effectively unavailable nearly half the time it's needed.

Extreme weather exacerbates these vulnerabilities. Cold snaps, heat waves, and storms have all exposed coal's fragility during grid stress events. Reliability is not just about being dispatchable, it's about delivering performance under stress. Coal plants struggle to do that consistently. For coal plants to truly meet the constant demands of data centers, they would need to run at high-capacity factors and avoid major outages, all of which fly in the face of current performance trends. If a large coal plant trips offline while supporting a cluster of data centers,

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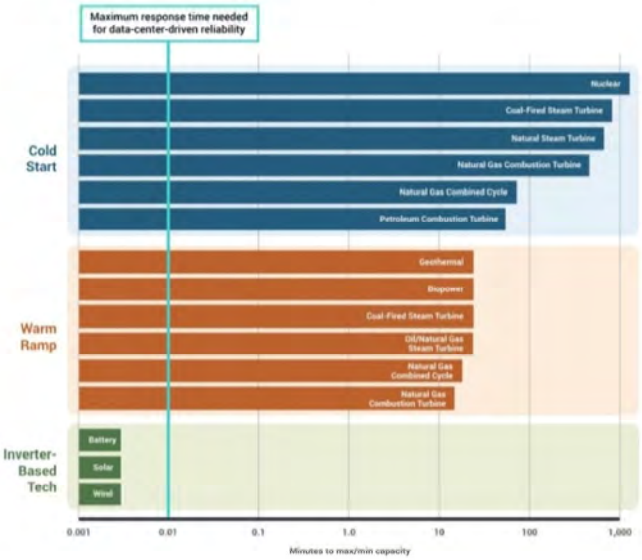
the sudden loss of supply could lead to cascading failures across the grid. This is because generation must equal load at all times, datacenter or no datacenter. As a result, relying on coal plants to support these high-density digital loads doesn't enhance reliability, it endangers it. And it's not a matter of *if* the coal plant will fail, but *when*.

## Reality #2: The inflexibility of coal plants risks grid stability

Coal boosters often point to the "always-on" nature of coal plants as evidence of their reliability. But that characteristic is a liability, not a strength, when it comes to supporting large, fast-changing loads like data centers. Coal units are inherently inflexible: they ramp slowly, respond poorly to sudden load shifts, and are difficult to turn on or off quickly. This rigidity is a poor match for the dynamic and often unpredictable nature of data center demand. Further, inflexible coal plants can worsen grid congestion; by occupying limited transmission capacity with inflexible generation, they prevent cheaper or cleaner resources from being delivered. This issue has already been flagged by **independent market monitors** in regions like MISO – which covers 15 US states and a Canadian province – where congestion-related market distortions have cost **over $1 billion a year**. Coal plants displace faster-responding resources that are better suited to follow load. And the stakes are high.

As noted by the North American Electric Reliability Corporation (NERC), large, voltage-sensitive loads like data centers require flexible, responsive grid solutions, not slow-ramping generators that can take 12 or more hours to come online. NERC's recent ***Incident Review and Guidance on Voltage-Sensitive Large Load Integration*** describes an event in 2024 where a transmission fault triggered a sudden disconnection of 1,500 megawatts of voltage-sensitive data center load, leading to sharp frequency and voltage spikes that required operator intervention. The incident exposes the system's vulnerability to instability when inflexible generation cannot respond to large load fluctuations.

**Minutes needed for a power plant to reach max/min capacity**




If a data center either loses access to load or goes offline rapidly, a grid's generation needs to respond at sub-second speeds. The average coal plant ramp rate is **4 percent per minute** which translates to spending over 20 minutes to respond to a large load event. From a cold start, the average coal plant would take over **12 hours** to reach max capacity. Coal plants simply can't respond fast enough to support the reliability needs of modern data centers. Whether it's the hours-long startup time from a cold state or sluggish ramp rates to turn off, these plants are too slow to provide the real-time flexibility required during sudden load changes or outages.

## Reality #3: Clean resources are available now that can better respond to and support data centers for less

The good news is that we don't need to rely on brittle coal plants to meet the needs of a digital economy. A range of cleaner, more resilient solutions is already available – and scalable. For example, we recently found that **more than 95 percent** of future demand can be met with fast, scalable, and clean solutions:

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### Alternative near-term solutions to meet load growth

| Technology | Opportunity |
|---|---|
| Energy Efficiency | Over 50 GW of energy efficiency can be deployed – by both creating programs for new loads and expanding existing programs aligned with system needs. Energy efficiency can unlock benefits beyond system cost savings, improving comfort and resilience in homes. |

| | |
|---|---|
| Virtual Power Plants | 60 GW of virtual power plants can be deployed by 2030, with programs stood up and enrolled in under 6 months. Policymakers in Virginia recently passed a bill that requires 450 MW of VPPs deployed rapidly to meet growing demand. |
| Advanced Transmission Technologies | Grid enhancing technologies and reconductoring can unlock over 80 GW of incremental peak capacity by reducing transmission and interconnection constraints. Lawmakers in New Mexico passed a bill requiring utilities to assess the use these technologies in plans to get more out of the existing grid. |
| Clean Repowering | There is 14 GW of fossil-fuel generation expected to retire, that could serve as sites for quick addition of new renewable energy and storage while reducing system costs. Market operators like PJM are enabling clean repowering by updating rules to allow for surplus interconnection. |
| Power Couples | New load can be co-located with renewable energy at the site of existing, underutilized generators with approved interconnections—a strategy which we call "Power Couples." There is over 30 GW of opportunity to deploy Power Couples under $100/MWh, and over 50 GW of opportunity under $200/MWh. |

Coal plants are a legacy technology, not a solution for the future. Coal plants' operational characteristics make them less suited to meet the scale and speed of these new challenges. The path forward is not about discarding the past, but about building on it with cleaner, more adaptable resources that can reliably serve evolving grid needs.

Technologies like battery storage, demand flexibility, and clean energy portfolios offer practical, cost-effective options that align with modern load dynamics. As we noted in a recent **article**, by running coal plants only when it is economical to do so and using the extra transmission headroom that creates to reinvest with clean energy upgrades, our grid can support the next wave of economic growth with the flexibility it demands. There are reasons to manage the shift to new, clean resources **thoughtfully and intentionally**, but propping up coal plants that are not suited for the job is a step in the wrong direction.

## RECOMMENDED READING



### Gas Turbine Supply Constraints Threaten Grid Reliability; More Affordable Near-Term Solutions Can Help

June 18, 2025

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### Reinvesting at Coal Plant Sites with Clean Energy Upgrades Supports both Reliability and Affordability

July 16, 2025

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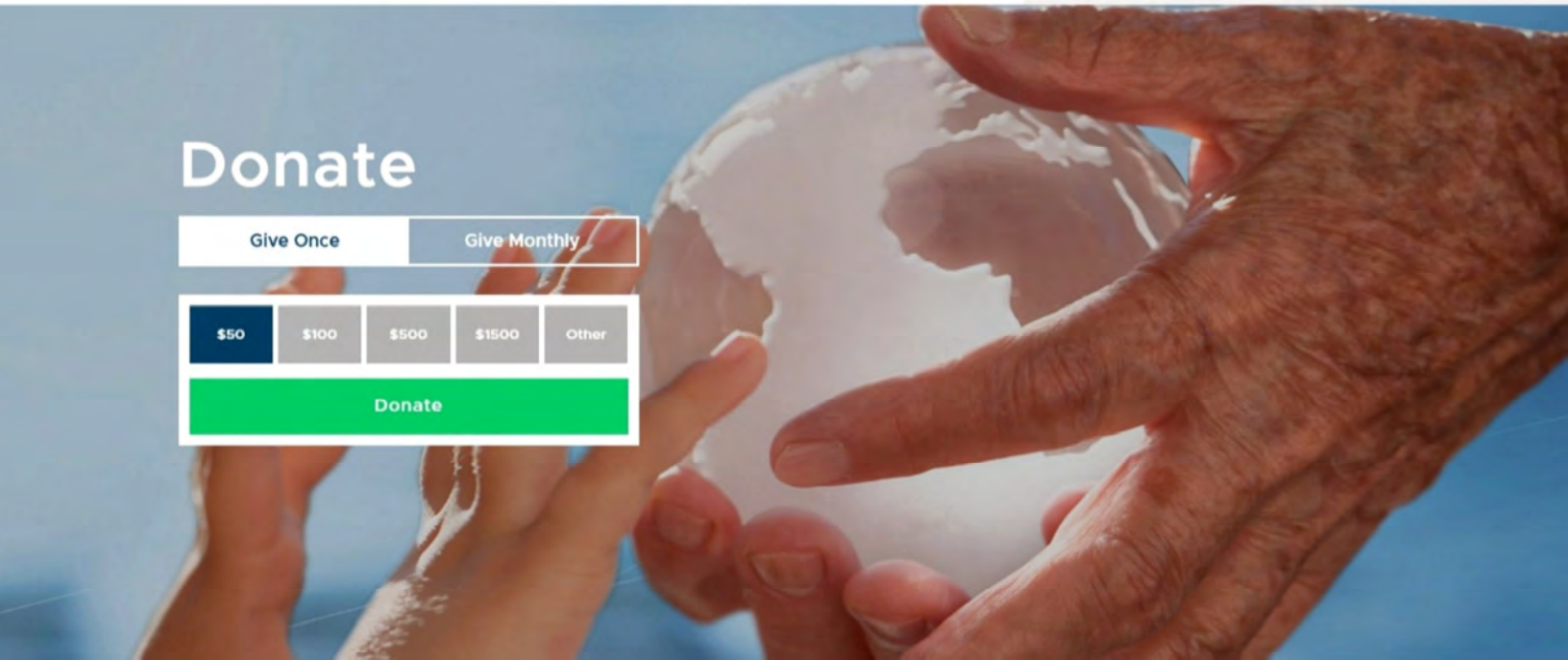

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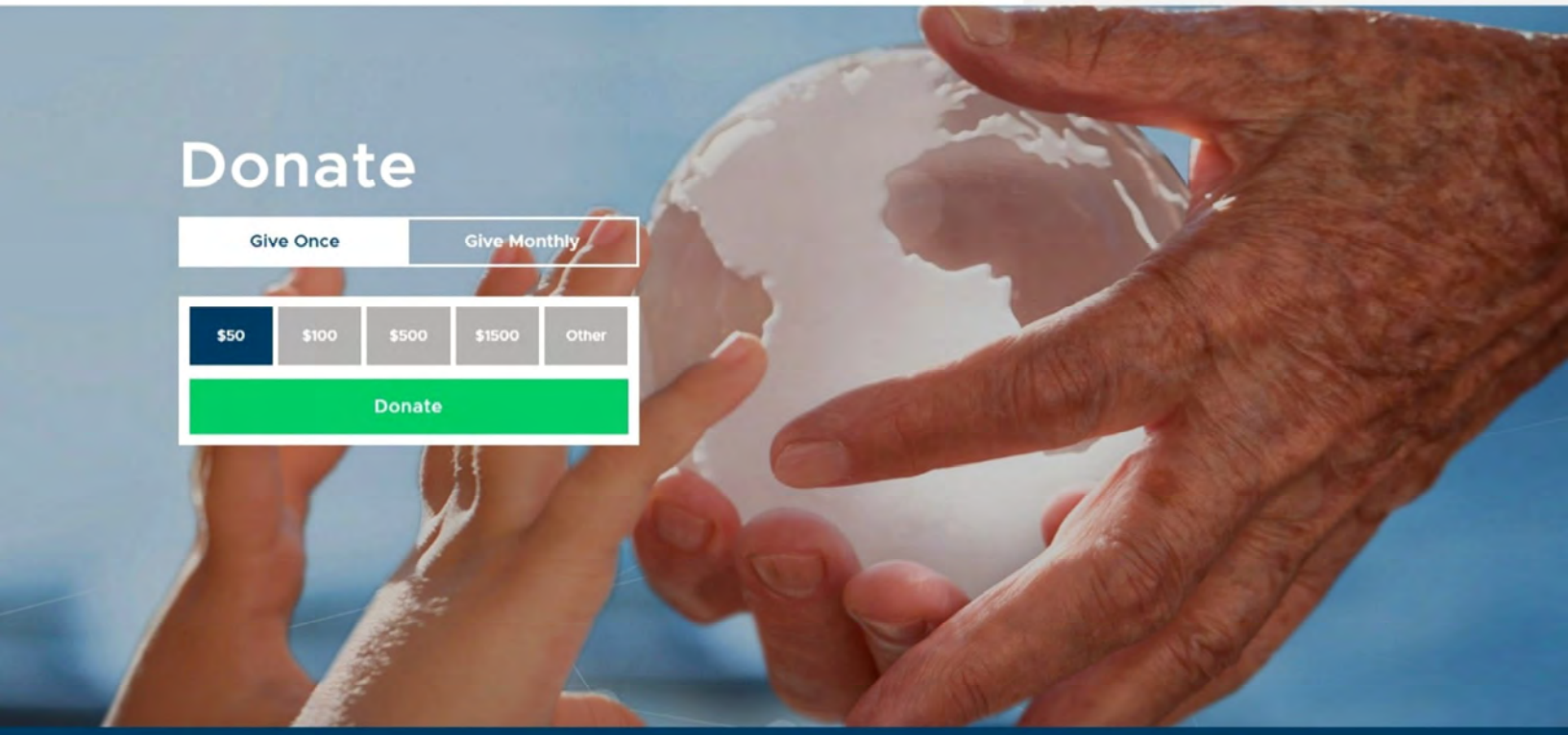


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| PacifiCorp, and Xcel Energy | ) |

Exhibit to
Motion to Intervene and Request for Rehearing and Stay of
Public Interest Organizations

Exhibit 2-45:
Energy Innovation Report



ENERGY INNOVATION
POLICY & TECHNOLOGY LLC®

# DODGING THE FIRM FIXATION FOR DATA CENTERS AND THE GRID

**Eric G. Gimon**

**Senior Fellow, Energy Innovation**

**November 2025**

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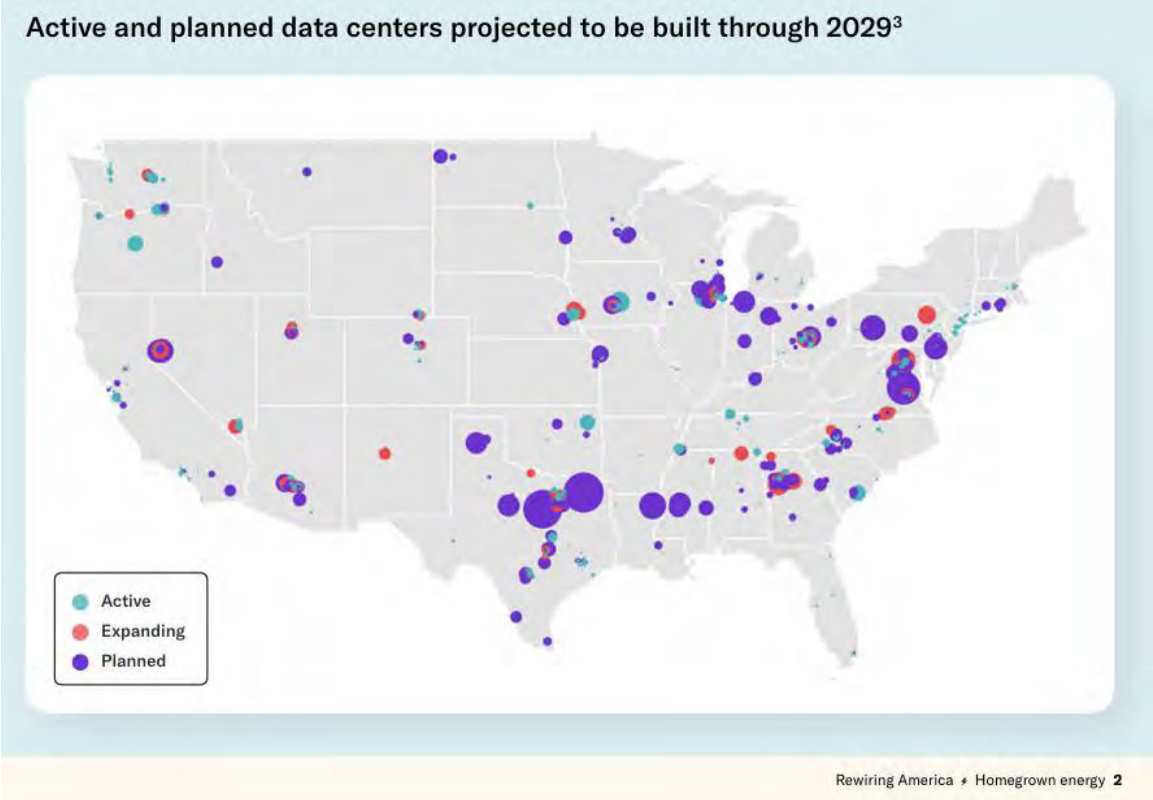
# EXECUTIVE SUMMARY

In multiple states[1,2] (see Figure 1) massive new data center campuses and a coterie of smaller ones have reversed years of flat or declining electricity demand, leaving utilities and policymakers scrambling for solutions.

*Figure 1 Existing and Projected data centers from Rewiring America's "Homegrown Energy" report[3].*




Faced with this onslaught of new demand, many utilities and developers are depending on old habits by adding new gas plants, refurbishing coal units, or turning to nuclear partnerships along with extensive grid upgrades near new load centers – the "firm fixation."

It reflects a belief that only firm resources and major transmission upgrades can handle data centers' needs. Yet this approach overlooks two essential truths: (1) power plants and data centers are both parts of a larger, interconnected system, and (2) data center loads, especially those driven by artificial intelligence (AI), are far more dynamic than the flat, baseload profiles they are often assumed to be. Firm fixation leads utilities and regulators to default to outdated firm-generation solutions instead of modern, modular approaches that consider the full complexities of today's power grid. At the scale of even the most compact new data centers, connecting to the grid is no small matter.

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Regardless of approach, three features of recent growth are well known to the electricity industry and policy community, and to some extent the wider public. First, new data center load is being amplified by extreme investment interest in AI. Second, incremental load tends to be highly concentrated due to the nature of the growing individual server need for power and the geographic concentration of data centers. Third, the data center industry's appetite for new growth is so large, and other facility capital costs so high that new project owners are willing to pay more for power than average existing electricity consumers.

In a 2024 brief, Energy Innovation proposed instead that a portfolio of solutions – clean energy portfolios, advanced transmission technologies, demand-side flexibility, and efficiency – could work together to obviate the need to rush to meet demand with new fossil generation.[4] Reality so far has deviated significantly from this vision, setting up the power sector for failure: Either new demand will not be met or the negative cost and performance impacts of doing so on other grid users will challenge electricity markets and other long-standing arrangements in a dangerous manner.

The mad scramble to meet data center demand using traditional but crude resource investment methods can create potential missed opportunities to manage load growth that come from a deeper understanding of data centers. Of course, their electricity demand is problematic because it is concentrated, growing fast, and willing to outspend other users. However, it is also far more complex than the flat, 24/7 block it is often assumed to be. This primer identifies six defining features that provide a more nuanced version picture of data centers:

- **Agency and Split Incentives** – Multiple actors (developers, operators, and tenants) and ownership or usage types of data centers create a divided responsibility over grid interaction and access to energy-saving incentives that complicates energy decisions.
- **Clustering** – Facilities tend to concentrate geographically, amplifying local grid stress and transmission costs while creating systemic planning challenges.
- **Consumption Profiles** – Loads are not 24/7 blocks. Instead, they are choppy, with swings of hundreds of megawatts over short intervals, undermining assumptions of steady baseload behavior and potentially affecting the stability of the grid if safeguards are not put in place.
- **Flexibility** – While some AI-driven workloads can be scheduled for off-peak hours, this flexibility is uneven across facility types and even within users in the same data center campuses. While modest levels of curtailment or load-shifting based demand response during peak hours could ease interconnection bottlenecks and peak demand requirements, these may work best in combination with battery energy storage to overcome split incentives and other complexities.

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- **Backup Requirements** – Current reliance on diesel for backup generation is unsustainable. Batteries and longer-duration storage are cleaner, more scalable options that provide knock-on benefits for the grid if allowed to participate as both backup and demand response.
- **Modularity** – Data centers grow in phases just as demand grows in phases rather than all at once, aligning poorly with "lumpy" firm large one-time investments in dispatchable power plants and infrastructure upgrades, while fitting well with modular renewables and battery deployments.

When examined as a whole, these features undermine the firm fixation logic. One-to-one matching of data centers with dedicated or "captive" firm power plants is particularly unwise for both the power generator and the new data centers, even given their willingness to pay for speed-to-power. Relying on captive plants for all supply such as pairing a nuclear plant with a large data center exposes them to outages, inflexibility, and stranded-asset risks, while hybrid co-location deals still rely heavily on the broader grid.

Most new demand will need to be served fully or in-part through the bulk power system, requiring upgrades in three key areas: **connection infrastructure, grid services (especially peak capacity), and bulk electricity supply.**

Once this is established, it's clear that data centers can tap the grid's advantages as a "system of systems" that pools variable demand and generation resources solutions together and ensures supply and demand match in real-time. As peak demand rises, this crucial service must be met, but not necessarily by firm generation. A deeper understanding of data center demand attributes yields a more complete solution set which includes data center flexibility, onsite storage, portfolios of clean energy, and others.

The challenges data centers pose include lengthy interconnection queues, peak stress, price impacts, and rising emissions – but these are not insurmountable. Three core lessons emerge for policymakers and stakeholders:

- The process of connecting any new **large load is a key leverage point.** It is the moment to ensure consumption tariffs reflect cost causation, encourage flexibility, and align incentives without imposing unworkable burdens later. Interconnection is the moment of maximum leverage: not to extract unreasonable concessions, but to ensure new entrants cover the full costs of the infrastructure they trigger, and to nudge data center developers towards solutions such as flexible demand or local storage that relieves local bottlenecks and supports the broader grid. Likewise, developers and customers should lean toward local fixes that speed access to the grid, improve power quality, and ease broader impacts—reducing the likelihood of being saddled with extraordinary requirements later.

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- **Demand side is a resource hiding in plain sight**. Household electrification and distributed resources can free up tens of gigawatts (GW) at costs comparable to new gas plants and on a faster timetable, offering a more pragmatic and equitable path to integration. Yet at the state and regional level, policy innovation still lags behind. However, several widespread mechanisms exist to channel data center owners and operators' willingness to pay into new solutions that help other existing customers accommodate rapid data center load growth in a fair, fast and equitable way. Because grid connection bottlenecks can be managed by multiple possible combinations of diverse resources, data centers don't need to do all the work of mitigating their grid impacts onsite or through a single counterparty. Once a data center has invested in flexibility and equipment to resolve local connection issues, additional constraints such as upstream transmission and grid services bottlenecks as well as large incremental amounts of annual electricity delivery can be addressed with demand-side solutions from other grid users. A recent report from Rewiring America proposes that many of the resources needed to meet data center load growth could come from sponsoring household upgrades instead of new generation.[5]
- **Storage and flexibility deliver a two-for-one win.** Batteries and managed demand not only ease all manner of data center impacts but can also accelerate renewable integration, providing cleaner, faster, and cheaper capacity than firm fossil solutions. Because batteries are increasingly essential for buffering, backup, and power quality, they also provide a built-in solution for integrating variable renewables—a two-for-one advantage. Furthermore, these renewable-plus-battery solutions can capitalize upon existing surplus interconnection to more quickly connect data centers to the grid in co-located arrangements.

This report challenges the electricity and data center industries to move beyond a firm fixation and adopt solutions that leverage the full capabilities of modern power systems.

The next section describes six defining features of data centers: agency, clustering, consumption profile, flexibility, backup needs, and modularity. We then pivot to explaining why traditional firm responses fall short within the broader context of how the modern grid supplies power to consumers, especially large, new consumers. We will look at how new, modular solutions can meet digital demand more effectively. These steps will depend on a more nuanced understanding of data centers, as opposed to how they are often imagined.

Our hope is that this information will empower policymakers to make wiser decisions when faced with AI growth and proposed public investments, avoiding a firm fixation on simplistic approaches and reaching for more realistic answers that embrace the full complexities of the challenge that rapid data center load growth presents today. By moving beyond simplistic assumptions, policymakers can avoid overcommitting to

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outdated firm resources and instead adopt strategies that embrace modularity, flexibility, and clean energy. We want to leave policymakers with three key takeaways to avoid falling into a firm power matching fallacy and to instead embrace the ability to mix and match resources to meet data center needs.

What began as a major strain on the grid can become the catalyst for building a smarter one, supporting both the digital economy's explosive growth and the clean energy transition.

## COMMERCIAL AND INDUSTRIAL REALITIES THAT APPLY TO DATA CENTERS

**Actual data centers are not the simple "flat 24/7 block of demand" people imagine.**

Six different demand features of data centers explain the diversity of data center types (agency, clustering, and profile) and their internal workings (flexibility, backup, and modularity).

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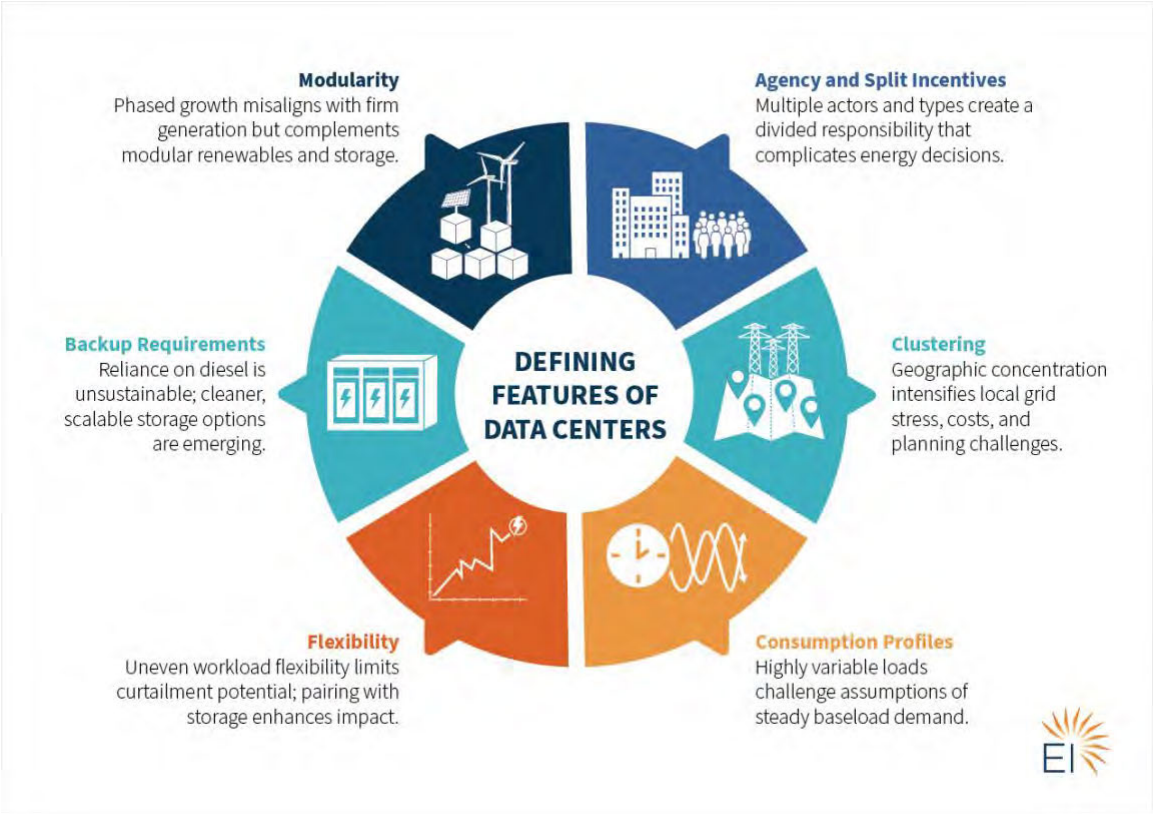
*Figure 2 Actual data centers are not the simple "flat 24/7 block of demand" people imagine.*




## Data Center Feature 1: Agency and the split-incentive problem

Planning *and* operating *a data center* involves many decision-makers. *Some data centers (often called co-locations or "colos") are facilities where customers can rent space to house their servers and equipment or just run their software on provided equipment. This means the facility is developed and owned by a different company* from those *that rent rack space, buy* computing *capacity, and ultimately consume electricity. Multiple actors force complicated decisions around electricity supply.*

If we want new data centers to adapt their development approach to better integrate with the grid and increase their "speed-to-power," policymakers must understand the planning, construction, and operation of modern data centers. Many different actors are involved, creating a classic split-incentive problem. Loosely speaking, apart from the users or clients, three groups of actors dictate the energy and resource impacts of data centers: developers, facility operators, and service providers. These tend to be separate entities. Overlap sometimes occurs, but usually not enough to prevent split-incentive

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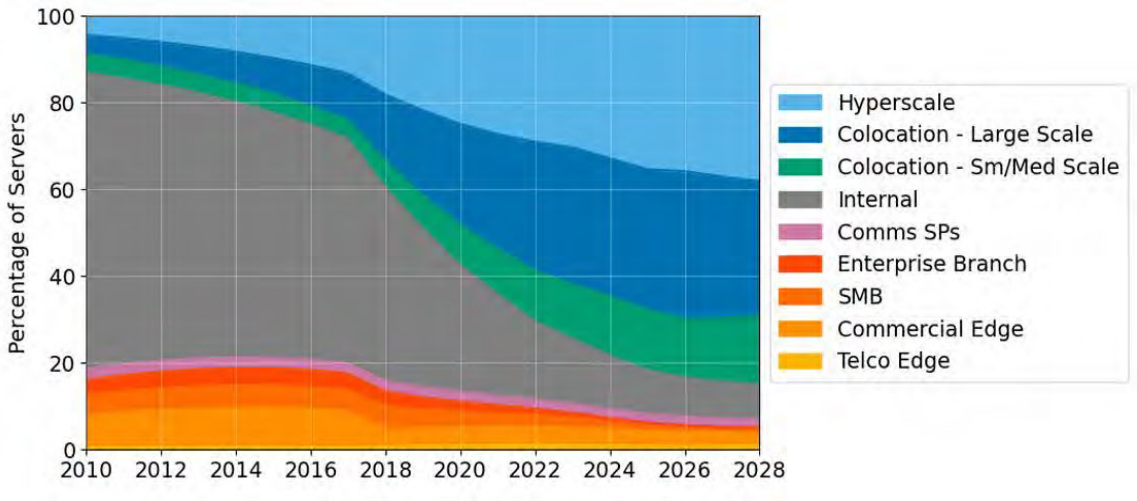
issues. More than half (and an even larger fraction of the current pipeline)[6] of data centers are categorized as co-location facilities—large facilities that rent out space to multiple separate entities.

*Figure 3 Distribution of server types by data center type. 2024 United States Data Center Energy Usage Report*[7]




We illustrate the split incentives by cataloguing some of the key concerns for each of the three types of decision-makers in the life of a data center. In early stages, data center development is mostly a real estate bet: developers acquire land, water, and electric connection rights and then these rights pass on to the projects they sell. The natural incentive for developers is to keep the range of future owners they could sell to as wide as possible. Hence, they are unlikely to want to enter contracts or agreements (or support legislation) that might prematurely impair any of the land, water, and power consumption rights for their projects. For example, they may not want to agree to be a flexible consumer in return for faster interconnection (load interconnection currently takes three to 11 years) because that might scare off some prospective buyers.

Similarly, owner/operators that lease capacity to data centers customers do not necessarily have much insight into how flexible these customers are or how their customers' usage pattern might change over time. They are conservative about aspects such as whether the tenant-user would be interested in avoiding on-peak usage, participating in time-varying rates, accessing clean energy tariffs, or participating in a demand-response program. Obviously, renters must abide by some rules (via master service agreements or service-level agreements[i]) about behavior that impacts power quality (voltage, frequency, harmonics, transients, etc.) or broader

[i] A master service agreement is an umbrella standardized contractual framework between a utility and the "customer of record" (which could be a data center owner/operator, a tenant/end-customer, or a special purpose entity created to hold the contract) across multiple facilities in the utility's territory. A load serving agreement is more specific to power delivery at a given site.

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electrical concerns (like grounding, interference, and surge protection), but that still leaves a lot of uncertainty for the data center owner/operator. Violations may also pass undetected until a severe problem occurs.

Because data centers are also large electricity consumers, utilities will want to know if contracts are backed by the ultimate users (e.g., hyperscalersii) or an intermediate company that could go bankrupt or disappear. Grid investments involve assets with multi-decadal lifetimes, while the service life of cutting-edge chips can be two to three years. Utilities and their regulators have a strong interest in recovering any incremental costs of investments needed to serve data centers and will look for contractual arrangements to make this happen.

### Data Center Feature 2: Clustering, data centers are attracted by similar conditions or to each other

*Data center locations tend to be concentrated in a few regions rather than evenly distributed. This clustering amplifies stress on already energy-dense grids. The main drivers are favorable conditions—reliable power, dense fiber, skilled workforce, tax regimes, and land—but anchor investments by hyperscalers or AI campuses could also accelerate the process. Policymakers should avoid treating projects as one-offs and consider the likelihood of a single facility snowballing into a larger cluster.*

"Clustering" describes how data centers in the U.S. tend to collect in a handful of regions rather than being evenly distributed. Clustering creates stress for the bulk power system because it takes already energy-dense loads and adds even more load nearby. The easiest explanation for clustering is that it derives from favorable existing conditions: reliable electricity, dense fiber connectivity, neighboring trained workforce, supportive tax regimes, and land availability.

Large anchor projects also draw in more data center development: Once a hyperscaler or AI training facility establishes itself, it signals viability, brings new infrastructure, and lowers costs for additional entrants. Policymakers wanting to provide support for a big project by promises of jobs and tax revenue, risk underestimating the impacts of this attractive force as welcoming one project may quickly lead to a cascade of follow-on facilities, with both outsized benefits and mounting strains.[8]

Recent history reveals a pattern whereby anchor investments amplify favorable local conditions into enduring centers of digital infrastructure. Northern Virginia's "Data Center Alley" grew from early fiber and internet exchange into the world's largest concentration of data centers. Amazon Web Services (AWS) was an early and steady

---

[ii] A hyperscaler is a cloud service provider or operator that builds and manages massive data center networks supporting millions of virtual servers and petabytes of data, operating globally and designed to scale seamlessly across regions. Examples might include Amazon Web Services (AWS), Microsoft Azure, Google Cloud Platform (GCP), Meta (Facebook), Apple, Alibaba Cloud, and Tencent Cloud.

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investor in this cluster.[iii] Today, Data Center Alley reportedly handles roughly ~70 percent of the world's internet traffic, contains over 12 million square feet of commissioned data center space, and sustains hundreds of megawatts of power load.[9]. Reno's Tahoe-Reno Industrial Center became a global hub after Switch and Apple established major campuses, followed by Google and others[10]. Central Ohio offers a newer case: Google and AWS each invested in major builds, quickly attracting colocation providers.[11]. Atlanta and Phoenix look to be on similar paths[12].

In theory, diverse types of data centers should reinforce these patterns. Colocation facilities are drawn to network-dense hubs where they can maximize interconnection to other facilities. For example, enterprise servers might want to easily connect to multiple cloud providers—providers of cornerstone internet services stand to benefit from the reduced latency proximity affords, especially for content delivery like streaming video and games and so on. Hyperscalers could function as anchors, just like a department store in a shopping mall, investing billions into single campuses that create the vendor ecosystems others rely on. However, AI-focused facilities, with their unprecedented power needs, can also reshape the landscape by displacing other data centers competing for the same power network and generation resources.[13]

Electric power infrastructure both attracts and is stressed by clustering. Access to transmission lines and substations is a prerequisite, but as clusters grow, demand can overwhelm grids. Northern Virginia now faces multi-year waits for new hookups[14]. Reno's growth has raised water concerns and left Nevada utilities facing a potential doubling in necessary electrical infrastructure (also spurring them toward large renewable additions)[15]. Ohio illustrates the stakes most vividly: By March 2023, the utility AEP Ohio imposed a moratorium on new data center service agreements in Central Ohio, pending further study citing grid strain. Eventually regulators approved a new tariff[16] requiring data centers to pay for 85 percent of subscribed capacity whether it is used or not, with penalties for cancellation or under-performance and a four-year on-ramp[iv]. Clustering behavior can easily outrun planning and force regulators into reactive steps, introducing delays before more pro-active policies and tariffs can be put in place.

The policy lesson is not to avoid clusters—after all, they bring new jobs, tax revenue, and digital infrastructure—but to keep a skeptical eye on benefits claimed by developers and focus on smart planning. This should consider the multiple interests of stakeholders affected by a data center cluster and work in advance to align land use,

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[iii] AWS is certainly not the only part of this story but has been called out as a major player. Dan Swinhoe, "The Amazon Factor in Virginia," Data Center Dynamics, November 6, 2024, https://www.datacenterdynamics.com/en/analysis/the-amazon-factor-in-virginia/. Amazon also touts its $51.9 billion investment in Virginia between 2011 and 2021 (capital + operations) in its data center infrastructure in Fairfax, Loudoun, and Prince William counties. Roger Wehner, "Learn About AWS's Long-Term Commitment to Virginia," Amazon, June 7, 2023, https://www.aboutamazon.com/news/aws/aws-commitment-to-virginia.

[iv] Under the decision, new data centers can access up to 50 percent capacity in the first year, 65 percent in the second, 80 percent in the third, and 90 percent in the fourth before getting full access to the grid.

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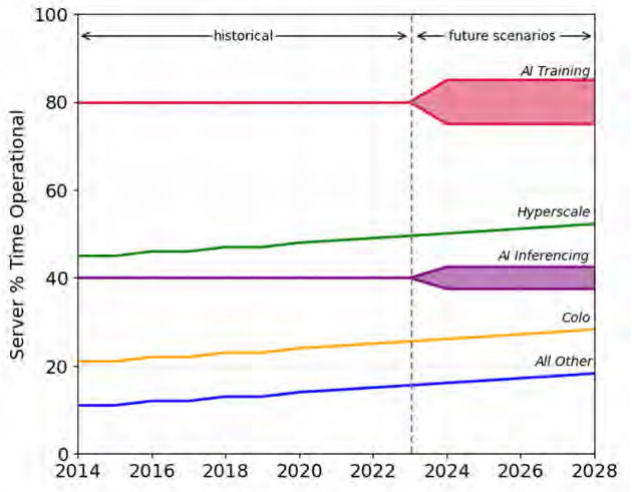
grid upgrades, generation, flexible loads, and permitting frameworks, ensuring that benefits can be captured without bottlenecks or backlash once clusters grow.

### Data Center Feature 3: Consumption profile

*Data center electricity usage is not steady or 24/7. Up close, it can be quite choppy and challenging. Batteries could act as a buffer—a keystone solution to managing power quality.*

*Figure 4 Server utilization by data center type. 2024 United States Data Center Energy Usage Report (LBNL).*




Data centers exhibit considerable variability, especially going between operational and idle states. In Lawrence Berkeley National Laboratory's (LBNL) 2024 United States Data Center Energy Usage Report, the authors explain that in 2014 colos reported 21 percent utilization rates, hyperscalers 45 percent – rising to an estimated 35 percent and 50 percent respectively in 2027. The same report models AI learning centers and AI inferencing at 80 percent and 40 percent utilization rates, respectively. These don't directly translate into electricity consumption load factors because some electricity is used for other purposes like cooling that don't follow a 1:1 relationship with computing load.

Even looking at the whole power consumption profile of a data center, it's important to differentiate between actual load factor (the percentage of possible 24/7 full power use that a data center in fact uses) and availability (the percentage of maximum power a data center expects to have if it wants it, i.e., the *option* to use power). Whether power comes from on-site generation or from the grid, it needs to be prepared to provide power when the data center wants it, and back off when the data center doesn't.

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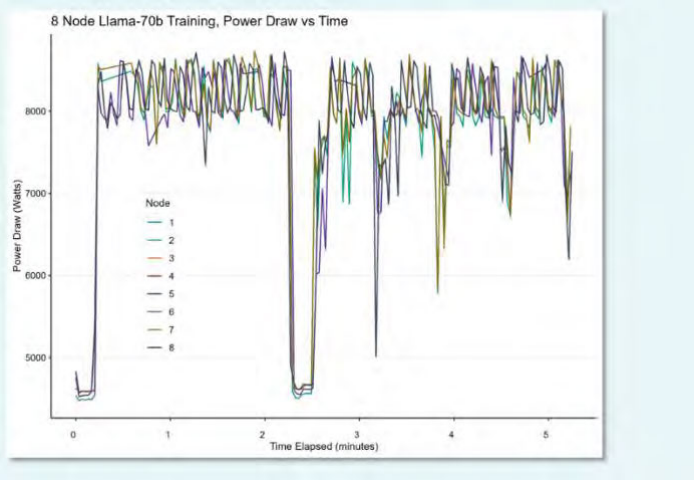
*Figure 5 8 Node trace of power consumption in an AI learning cluster. 2024 United States Data Center Energy Usage Report (LBNL).*




Big swings in data center demand will clearly be a challenge, even for the most flexible on-site generation. Given the scale at which many data centers operate, these swings can still create problems for large regional grids[v]. The CEO of Hitachi Energy reportedly commented "there can be swings of 200, 300 MW within a ten-minute period as data centers move from learn vs stop learn mode, and that these types of swings would not be acceptable from other grid customers."

At smaller time scales, large numbers of similar chips in one place switch on and off and can create an aggregate resonance effect[vi]. Existing electrical standards are inadequate for screening out these behaviors, and utilities may not have sufficient sensors to properly trace back issues to a particular data center. In aggregate, the evidence points to data centers deteriorating power quality metrics in their environs.[17]

More research needs to be done that focuses on new large digital loads, including variable generation resources with inverters that center around things like low-voltage ride through or fault clearing. For more information, context, and solutions on some of the challenges with interconnecting these large loads, see GridLab's recent Practical Guidance and Considerations for Large Load Interconnections.

Data centers are not a "perfect baseload" fit to directly couple with large mechanical generators or even the grid, and they will need significant electrical equipment to buffer this connection and prevent extra wear and tear on co-located generation or nearby grid users. Even if some data centers can learn to be flexible, incorporating battery energy storage, especially as the hardware cost decreases, will likely become a key element in managing data center impacts on the grid. When good wind and solar resources are available nearby, batteries can play a dual role in managing both load and generation variability at multiple time scales. Consider the Lancium Clean Campus in under construction in Abilene, Texas: "In addition to the 1.2 GW grid interconnection,

[v] See the GridLab report *Practical Guidance and Considerations for Large Load Interconnections*, with special attention to July 2024 Northern Virginia Data Center Event called out in Figure 1.2.
[vi] Some of these resonance issues can potentially be solved by on-chip energy management and storage. Rouslan Dimitrov et al., "How New GB300 NVL72 Features Provide Steady Power for AI," Nvidia, July 28, 2025, https://developer.nvidia.com/blog/how-new-gb300-nvl72-features-provide-steady-power-for-ai/?utm.

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Lancium's power plan for the site includes large-scale behind-the-meter battery storage and solar resources, which serve to ensure grid reliability, and economic and carbon optimization."[18]

### Data Center Feature 4: Flexibility, or the lack thereof

*Flexibility could be key to quickly connecting new data centers, especially those involved with AI learning. Managed demand is possible, but on-site batteries may be a better solution where split incentives or onsite needs make demand control too rigid or complex.*

Data centers can be flexible, but different functions involve different levels of flexibility. This is probably hardest to achieve for co-location data centers because the third-party owner which interfaces with the grid and with utilities is not the one deciding what servers inside its facility are doing. Additionally, data centers are tasked with fluctuating sets of applications, creating uncertainty about how reliable or persistent demand management can be as a means of providing flexibility.

Data centers fully owned by large hyperscalers provide a higher degree of control over the whole facility. But the diversity of services being provided, often with low latency (response times) needs, may create constraints on what the hyperscaler can do. Hyperscale data centers provide both regular services—like AWS' cloud computing—and AI workloads such as inference, which involves answering client queries using pre-processed AI models.

For AI learning data centers, which create these large learning models, the goal is to cram as many chips as possible into the same square mile with the fastest internal connectivity so that the collection can operate as one big parallel machine[19]. Much of the possible flexibility here comes from adjusting the timing of computing batches, yet matching these adjustments to power supply flexibility needs is not a given, especially when considering that data center operators will want to prioritize computation over flexibility. This is a consequence of the relatively larger size of the capital investment in computing hardware versus energy generation and distribution for most applications.

Flexibility is a particularly important quality for data centers because they are such a large component of load growth, and just a little flexibility would reduce the need for new peaking resources and speed up interconnection[20]. A 2025 analysis[21] by the Nicholas Institute for Energy, Environment & Sustainability at Duke University finds that just 0.5 percent to 1 percent flexibility opens significant space on the grid: 98 GW of new load could be integrated at an average annual load curtailment rate of 0.5 percent, and 126 GW at a rate of one percent. This level of flexibility is similar to what is provided by demand-response programs that exist today for other loads, but as far as speeding up interconnection, it may be the AI-driven hyperscalers and learning centers, acting more directly under their owners' control and schedules, that can achieve more.

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AI loads are fundamentally more flexible than generic data center loads because they can be processed in batches, easily scheduled, and often internally orchestrated. For example, in a presentation[22] to the Texas grid operator Electric Reliability Council of Texas (ERCOT), the company Emerald AI demonstrated how it could implement flexibility at a data center. The company argued there is enormous potential to control AI data center load, and that "major hyperscalers are amenable to curtailing up to 25 percent for up to 200 hours in return for priority interconnection of 1 GW."

No one knows if any particular data center's operations will remain stable enough to guarantee a given level of flexibility or willingness to curtail over the lifetime of matching local grid upgrades. In some cases, the data center load can be flexible (willing to forgo some batches of work) but not exactly in the way that best serves the local grid. Some amount of local battery energy storage (providing multiple value streams like integrating local on-site variable energy, backup, and power quality services) could also help data centers be more flexible at their grid interface, especially those with less direct control over internal processes.

### Data Center Feature 5: Backup needed for disturbances and outages

*Most data centers require backup. Demand flexibility and short-duration batteries can either eliminate or lighten the load for traditional backup solutions.*

Many data center customers aspire to high availability—as much as 99.999 percent uptime—hence the need for backup power to take over in case of any grid failure. The Uptime Institute, a widely followed source for industry tier certification in data center design, build, and operations,[23] defines four reliability tiers (I through IV) with increasing expectations for performance under challenging conditions, with an eye towards worst-case scenario planning. Many data centers serving enterprise needs require at least a Tier III level of reliability, either because of a direct need, like maintaining accessibility to data under adverse conditions, or as a proxy for operational trustworthiness. For mission-critical operations—major banks, stock exchanges, the military, or hyperscalers serving global customers—a Tier IV level of availability may be required.

Because Tier III and Tier IV facilities require 72 and 96 hours of on-site power capacity, respectively, simple economics dictate that backup is usually in the form of diesel generators with fuel storage on-site. Batteries can also be used to help ride-through disturbances in power supply,[vii] providing faster response times and reducing fuel and maintenance expenses on diesel. However, with today's technology, battery energy storage systems (BESS) that can cover critical needs for three to four days are not

[vii] In current facilities, this ride-through comes via the uninterrupted power system (UPS) usually provided by old-school lead-acid batteries, but modern lithium-ion battery energy systems can provide these services along-side the bulk of backup power needs.

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economically feasible, especially without some form of on-site generation to sustain their state of charge.[viii]

However, diesel does not scale well: As data centers get much larger, massive tank farms for the generators' on-site fuel require complex fire protection, spill containment, and environmental risk mitigation. Furthermore, many air districts (e.g., Virginia, California, or Oregon) place strict caps on generator run time and cumulative emissions in a site or region. Placing more than a hundred diesel generators on one site creates a cumulative permitting challenge and may well face serious local resistance along with the prospect of delays or outright rejection from regulators. Somewhat cleaner gas generators (turbines[ix] or reciprocating engines) are usually connected to a pipeline and require large propane or liquefied natural gas storage facilities to satisfy on-site capacity requirements.

Some large hyperscalers are opting to target better up-time based on statistical estimates rather than explicit proxies for reliability. For example, Microsoft has publicly committed to reducing the use of diesel generators by 2030. To that end, it contracted with Saft, a subsidiary of TotalEnergies, to install four battery energy storage systems, each in groups of four megawatt hours (MWh) and capable of 80 minutes of on-site power, to replace diesel backup.[24] In the U.S., Microsoft's newest Azure region in San Jose, California is also being built diesel-free, but is using natural gas turbines for backup (plus batteries for ride-through). In general, the U.S. grid is quite reliable, with the one-in-ten reliability standard[x] mostly achieved at the transmission service level.[xi] Most outages that do occur are less than one or two hours, so a battery can carry enough of the backup burden to get the facility to a high level of reliability while hardly, if ever, using on-site generation.

As longer-duration storage solutions like Form's 100-hour battery [25] or thermal batteries[26] connected to local renewables and steam turbines in local energy parks[27] emerge, data centers will be able to free themselves from fossil fuel backups while taking advantage of integrated design to combine multiple uses of batteries for flexibility, power quality, and backup.

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[viii] To see how this is done in detail, see the NREL Vulcan platform demonstration in collaboration with Verrus. Deepthi Vaidhynathan et al., "Vulcan Test Platform: Demonstrating the Data Center as a Flexible Grid Asset" (National Renewable Energy Laboratory, June 2025), https://www.nrel.gov/docs/fy25osti/94844.pdf.

[ix] Although gas turbines face significant supply chain cost and delivery challenges currently. GridLab, *Gas Turbine Cost Report*, https://gridlab.org/gas-turbine-cost-report/.

[x] The one-in-ten reliability standard is a standard that applies for the bulk power system (i.e. transmission level) requiring transmission planners, system operators and reliability planners to aim for nor more than one "event" of involuntary load-shedding in ten years. If one "event" was 24 hours, that is already 99.97 percent up-time.

[xi] Actual recent figures for grid performance are quite good (see table 1.1). North American Electric Reliability Corporation, *2024 State of Reliability*, June 2024, https://www.nerc.com/pa/RAPA/PA/Performance%20Analysis%20DL/NERC_SOR_2024_Technical_Assessment.pdf.

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### Data Center Feature 6: Modularity—data centers are built in phases

*Data centers expand in discrete phases, from racks to halls to entire campuses, with uncertain demand and rapidly rising power density. This modular growth pattern matches well with the modularity of renewables-plus-batteries deployment, which can be built in parallel to meet incremental load without the risks of lumpy firm power investments.*

For utilities and data center developers, timing capital investments can be challenging. Matching these investments with energy supply for their increasingly electric power sub-components compounds the challenge. Building a new data center means committing to constructing a large building and grid capacity without knowing if consumers will come, how quickly they will deploy, or how their consumption will evolve over time. Tenants in a co-location situation, hyperscalers, and AI data centers may not immediately have all the chips available (or face some other bottleneck) so may want to deploy in phases: slowly building up electrical demand over time until reaching full capacity, if all the anticipated demand materializes. With a chip service life of around two to three years, the balance between increased efficiency and increased computing power may mean newer chips could either increase or decrease electricity demand in each physical asset footprint.[xii]

The digital world's infrastructure is itself modular—built from discrete, substitutable units. Data centers are not just abstract systems of bytes and tokens; they are also collections of tangible components: chips, servers, and, above all, racks. The rack is the main unit of reference: a cabinet holding multiple slender servers or "rack units." Racks are grouped into "pods" of 20–30, and an enterprise client might deploy a couple of pods at a time in either a dedicated or co-location facility. Some tenants lease only a handful of racks in a shared space, while hyperscalers may build entire halls of 200–400 racks, with multiple halls forming a single phase of expansion on a large campus[28].

The modular nature of data centers lets developers manage financial risk by building in phases, with the option to add new capacity quickly but in a planned way. Each phase, however, carries high stakes not only in capital cost but also in power demand. A 2024 Uptime Institute report[29], states finds that four- to six-kilowatt (kW) racks remain common, with a trend towards higher consumption today. Meanwhile, AI applications and high- performance computing are pushing the development of liquid-cooled racks with incredible increases in power density. Vertiv, an Ohio-based company that designs, manufactures, and services critical infrastructure for data centers, reported in its 2024 Investor Event Presentation[30] that extreme rack densities already reach 250 kW

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[xii] This is certainly a question in flux. Google has reported that over a recent 12-month period, the energy footprint of the Median Gemini Apps text prompt dropped by 33x! At a given facility this can be achieved by increased throughput or reduced energy use, or both. Amin Vahdat and Jeff Dean, "Measuring the Environmental Impact of AI Inference," Google Cloud, August 21, 2025, https://cloud.google.com/blog/products/infrastructure/measuring-the-environmental-impact-of-ai-inference.

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per rack today and could exceed one MW within five years. That means a space the size of a bedroom closet could consume more power than a thousand average homes. As a result, a single phase of development for a data center might range from on the low end at 250 kW (two-dozen at 10–12 kW per rack) on the low end to 250 MW at the high end (a 1,000 liquid-cooled 250 kW racks) at the high end, with extra overhead for cooling.

The extreme end of data center development is exemplified by data center developer Vantage's recently announced plans [31] to build its $25 billion Frontier campus situated on 1,200 acres in Shackleford County, Texas, with an eventual total consumption of 1.4 GWs—close to average total consumptions of the states of either Rhode Island or Delaware. And this project is not alone: a September 2025 ERCOT staff report[32] to ERCOT's board details 130 GW of non-crypto data center load in the interconnection queue through 2030.[33] In the last few years, Texas has met new additional load with new, mostly clean generation. Of the 428 GWs of generation requests as of August 31, 2025, 204 GWs are for wind and solar and 180 GWs are for energy storage (together 90 percent of all requests).

Data center development may come in all levels of power consumption. However, because developers rarely build, install, and commission data centers in a single phase, projects of all sizes need a power supply that can grow and expand with them. When covering the incremental energy demand from a new data center, a large new single firm resource is an unwieldy indivisible capital investment. A modular approach with renewables plus batteries reduces risk and provides better economics: You're not committing to a single lump-sum investment in a 500 MW gas turbine; you can phase investments, optimize based on real usage, and spread spending—and risk—over time.

With computing loads that grow unevenly, modular investments let operators respond dynamically—deploy more solar, wind, or storage as AI racks come online. As a bonus, you can avoid supply chain bottlenecks because incremental installation bypasses the big lead times and equipment backlogs associated with large generator orders, enabling continuous expansion without project delays. Just as data centers grow in discrete steps, modular renewables and batteries let the grid grow in parallel.

These six features highlight why data center demand is complex, not just a flat, 24/7 block of constant load. We now turn to how supply options can, and cannot, match this demand.

## THE BEST WAY TO MEET DATA CENTER DEMAND IS DIVERSE RESOURCE PORTFOLIOS

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When thinking about how to supply new demand from the rapidly growing data center industry, the key point to remember is **one-to-one matching with "firm" resources will not "solve" the load growth needs from data** centers.

In this section, we explain why single, stand-alone generation resource matching for any given industrial load has rarely been the historical course, and how and why that might change. We then describe the three resource buckets that new data center projects need to acquire to use the existing bulk power system. Finally, we discuss how the data center demand features described in the preceding section create further challenges and barriers in acquiring these resources.

## Debunking the one-to-one matching myth

If you imagine data centers as large capital assets running power through expensive electronics 24/7, it seems natural to imagine a dedicated "captive" 24/7 power plant built to match this demand, with historical precedent for this one-to-one matching. For example, in the post-war era aluminum producer Alcoa built smelters near cheap grid sources of hydropower in New York and the Pacific Northwest along with captive coal plants in Indiana and Texas to feed the company's aluminum smelters and mills. Today, industrial facilities use on-site combined-heat-and-power (CHP) plants to consume both the electricity and waste heat from fuel-driven power plants to operate industrial facilities with high end-use efficiency, and thus lower energy costs. According to the U.S. Energy Information Administration's (EIA) latest Manufacturing Energy Consumption Survey from 2022, U.S. manufacturers produce around 17 percent of their electricity needs on-site (Table 11.1) and that on-site generation is 97 percent co-generation (Table 11.3).[xiii]

### Single plants may not "play nice" with data centers

The demand characteristics of data centers described in the prior section raise immediate concerns regarding matching a captive plant with a data center. For example, while a data center may want 24/7 availability, its actual consumption will ramp up and down significantly with a profile that a large, single on-site generator might struggle to meet. Many fossil generators have a minimum dispatch level they cannot fall below, and "ramp rates" limits dictate how quickly they can adjust up and down. Furthermore, a modular, phased build-out does not lend itself to a single matching resource because in order to provide sufficient power for the full buildout,

[xiii] This survey defines co-generation as "the production of electrical energy and another form of useful energy, such as heat or steam, through the sequential use of energy. Cogeneration includes electricity generated from fossil fuels, such as natural gas, fuel oils, and coal; wood; and other biomass." In practice, the steam/heat is the main other energy output, so co-generation is often used as synonymous with CHP.

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the single resource would have to operate at lower, inefficient, dispatch levels during earlier phases of data center construction and operation.

Beyond a mismatch with the demand characteristics of data centers described in the prior section, there are additional reasons to question using a captive plant as a 1-1 match for a data center.

### Captive power plants are not highly reliable alone

Table 4 from the North American Electric Reliability Corporation (NERC) 2024 State of Reliability Overview [34], shows the recent weighted forced outage rate (rate of unexpected failure) was 11.7 percent for coal, 7.7 percent for gas, 6.4 percent for hydro, and 2 percent for nuclear. Another relevant consideration is planned maintenance, like cleaning out coal boilers, maintaining and inspecting gas turbines, or refueling nuclear plants every 18-24 months.[xiv] This means a single supposedly "firm" plant will be unavailable for a double-digit percentage of time—not what data centers are looking for.

If an industry is set on self-supply, one strategy is to over-supply generation. Alcoa's Warrick, Indiana aluminum smelter and mill built three captive 144 MW coal plants alongside a 300 MW coal unit shared 50/50 with the local utility Vectren. With a total capacity of 732 MW but serving a local load of 550 MW,[35] the facility was clearly resilient to losing one unit and still running. But this effectively meant carrying 25 percent more capacity than necessary, without a guarantee of full reliability. Alcoa mitigated this extra cost by selling excess power to the grid and importing power from Unit 4 or the broader grid when necessary. This illustrates the general case that a grid connection remains both a sink for surplus and an important backup option; most on-site power is not fully independent and large loads will still want interconnection to the bulk power system. In fact, payment for grid backup (usually called "standby rates") is a common feature of CHP tariffs.[36].

### What happens when the power plant is no longer needed?

An interesting postscript to the Alcoa Warrick plant story is that Alcoa announced it would shut down its aluminum smelter in 2016 (although it had partial restarts post 2018) because of poor market conditions [37] and transferred major rolling mill and finishing operations to Kaiser Aluminum in 2021.[38] It is now left with an unattractive coal generation asset, whose generation capacity now exceeds Alcoa's local demand and

[xiv] This is on average a 32-day process. Aaron Larson, "Planning Is Key to Successful Nuclear Refueling Outages," POWER Magazine, September 1, 2023, https://www.powermag.com/planning-is-key-to-successful-nuclear-refueling-outages/.

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will likely struggle to sell surplus capacity in the broader power market along with most coal assets,[39] which comes with significant environmental remediation liabilities.[xv]

This is always the risk with a captive power plant: One day the load will vanish because of changing economics. Investors will want to know if Plan B exists and that the captive plant is in and of itself an attractive asset with a bright future.

### Co-location of prime power generation assets with data centers today

Grid bottlenecks create considerable talk about co-locating "prime power" generation[xvi] with new data centers. This might include leveraging existing nearby assets (for example, the Talen-Susquehanna deal which co-locates a data center next to a nuclear plant[40]), restarting mothballed generators, or building new on-site resources (such as gas plants). But these arrangements are not true one-to-one matches of generation with load, since they still depend heavily on a grid connection for full functionality, sometimes at the expense of other consumers.

For example, in the Talen-Susquehanna deal, the data center is physically adjacent to a pair of nuclear units. It is unlikely the units' output will ramp precisely in step with data center consumption. Therefore, matching local supply with demand creates net output—nuclear output minus on-site data center consumption—variability which must be managed by the grid operator. During the refueling of one nuclear unit, the other must pick up the data center load, thereby reducing exports to the grid. In effect, the grid acts as backup.

Hybrid arrangements using on-site power together with the grid can address bottlenecks. They combine physical and financial hedges. The Talen-Susquehanna deal, for instance, was eventually reshaped into a power purchase agreement after regulatory push-back.[41]. These hybrid deals share many of the properties—and many of the drawbacks—of other on-site generation deals discussed above.

If land is available, the best way to provide on-site prime power is not with a single firm resource but by using an energy park[42] with renewables and batteries, with backup from longer- duration storage and/or gas generators.[43] Then most of the generation is

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In 2024, Sierra Club and Environmental Integrity Project intervened in a case against Alcoa Warrick for "100+ permit violations" in 2022 and 2023, including releases of mercury, aluminum, chlorine, copper, fluoride, nickel, and zinc into the Ohio River. Environmental Integrity Project, "Groups Intervene in State Action to Stop Aluminum Smelting Plant's Illegal Dumping of Heavy Metals in Ohio River," February 21, 2024, https://environmentalintegrity.org/news/groups-intervene-in-state-action-to-stop-aluminum-smelting-plants-illegal-dumping-of-heavy-metals-in-ohio-river. There are also lingering questions regarding compliance for Warrick's "ash ponds" under the Environmental Protection Agency's Coal Combustion Residuals rules. Hoosier Environmental Council, "Today's EPA Action Means More Coal Ash Cleanup for Indiana" (press release), April 25, 2024, https://www.hecweb.org/wp-content/uploads/2024/04/PRESS-RELEASE-Todays-EPA-Action-Means-More-Coal-Ash-Cleanup-for-Indiana.pdf.

[xvi] Prime power is the continuous everyday power that powers the data center, as opposed to backup power There is also "bridge power" which is local generation which acts as prime power until a grid connection is put in place, and then becomes either backup or just a part of the supply portfolio.

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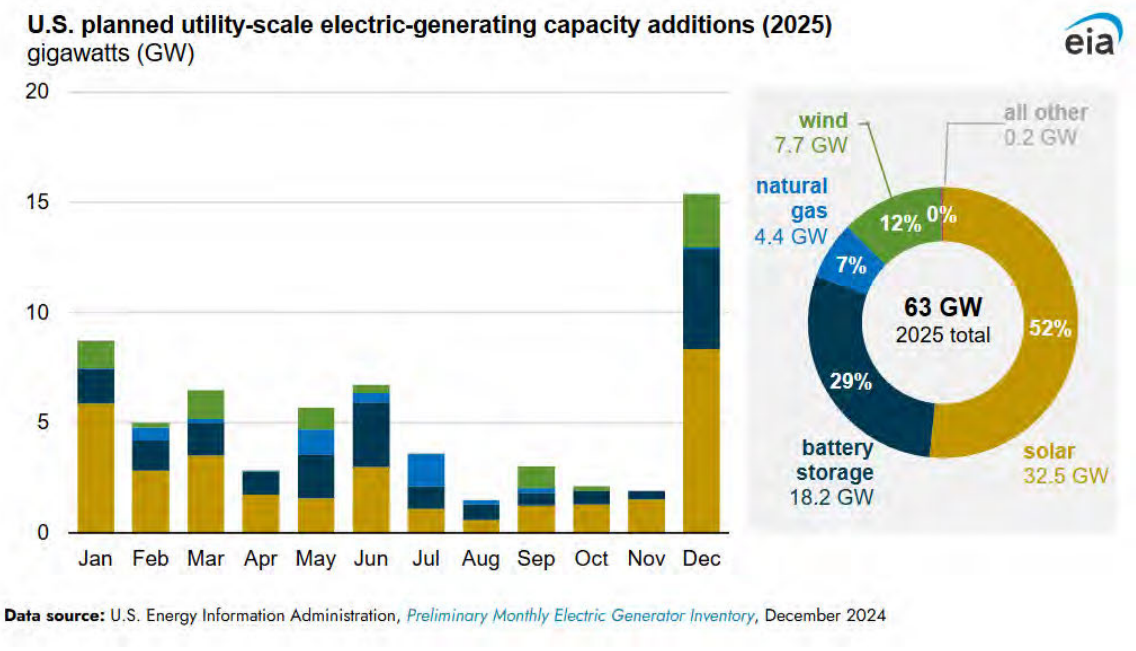
clean, faster, and cheaper to deploy than other generation and helpful for hyperscaler emissions commitments. In addition, the combined resource is more reliable, with fewer large points of failure than a handful of fossil units – a good Plan B if load never fully materializes or decreases. Included energy park resources would reflect a microcosm of trends in the wider U.S. market where the large majority of generation coming online[44] and waiting in interconnection queues are renewables and batteries.[45]

*Figure 6 Solar, battery storage to lead new U.S. generating capacity additions in 2025. US EIA.*




**Data source:** U.S. Energy Information Administration, *Preliminary Monthly Electric Generator Inventory*, December 2024

## Providing new electricity supply for data centers from the bulk power grid

Given that most data centers will need to get some, if not all, of their power from the bulk power system, it is helpful to review how large commercial or industrial loads do this. The power grid is a system of systems including physical transmission and distribution poles and wires, the generation and loads they connect, operations and dispatch, power markets, and power purchase agreements.

As soon as a large new load decides to connect to the bulk power system, its needs can be disaggregated and met in many ways.

The grid resources a new data center project must collect to successfully draw from the bulk power system fall into three broad buckets: connection, grid services, and bulk electricity.

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### New large data centers will require connection and network upgrades

How data centers connect to the grid depends on their size: scale matters. Smaller enterprise and co-location data centers (tens of MW or less) will often connect to a distribution system's high-end network (i.e., somewhere between 13.8 and 69 kilovolts) and may tie into an existing distribution substation with a new feeder. The utility typically owns and operates the primary substation equipment, while the data center customer owns the step-down transformer to its facility. The local utility conducts the impact studies and plans local upgrades to ensure compliance with NERC standards. Too many connections in the same area may trigger transmission upgrades and inclusion in transmission planning studies. In some geographies, like Virginia, this may involve an independent system operator (ISO) such as PJM [xvii] in planning and approving upgrades.

Larger data center campuses will have their own complex internal grid that connects directly to a bulk power system transmission substation. The data center must file a large load interconnection request with the local transmission owner or ISO. Tariffs and agreements will include matters like covering study costs, equipment ownership, and who pays for upgrades. The state may also require approvals for siting, environmental review, and cost recovery. The connection process can become long and painstaking once local capacity on the grid becomes tight. In Virginia's Dominion utility territory, data centers larger than 100 MW face up to a seven- year wait for power hookups.[46]

One important feature of new connection costs is that they are usually covered by the new load because cost causality is clear. Unfortunately, this may not hold true for more upstream transmission impacts where transmission upgrade costs are traditionally socialized more widely. A recent Natural Resources Defense Council (NRDC) report[47] tells the story in PJM: "Tight supply conditions led PJM to approve a $5 billion transmission expansion project to meet new data center demand in Virginia, where data centers already account for around a quarter of the state's electricity demand. The costs for this project were distributed by the Federal Energy Regulatory Commission (FERC), PJM, and utilities using varying cost allocation methods. Maryland residential customers were left with a bill of approximately $330 million, and Virginia residents had to foot $1.25 billion for transmission designed largely for a handful of data center customers in only a small region of the state."

### Data centers create new stresses on a bulk power system planned around peak demand; they also consume other grid services

The main grid service data centers require regardless of size is peak capacity: the ability to serve up to their maximum interconnection rating during periods of system peak.

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[xvii] Also referred to as a regional transmission operator, PJM covers 13 states in the mid-Atlantic and is one of the largest power markets in the world.

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Going back to PJM (often a source of current examples because it already serves so many data centers), the ISO's board chair communicated about future reliability concerns because: "PJM's 2025 long-term load forecast shows a peak load growth of 32 GW from 2024 to 2030. Of this, approximately 30 GW is projected to be from data centers."[48]

PJM's conundrum is how to keep the grid reliable as data center demand grows faster than new generation. Its "non-capacity-backed load" proposal would classify very large new loads (less than 50 MW) as customers outside the capacity market.[49]. The idea is to avoid shifting costs to others, but critics say that the 50 MW cutoff is arbitrary, curtailment rules could distort market signals, and contract and siting decisions may be disrupted.[50]. PJM is still debating whether the non-capacity-backed load should be voluntary or mandatory in shortage zones before filing at FERC for the 2028/29 delivery year.[51]

One challenge with resources like peak capacity is that once a project has been approved for interconnection, been built, and paid its share of costs, it becomes a load like any other. At that point, it is very difficult for the market to discriminate against it without creating efficiency concerns or legal risks. Data centers do more than strain peak supply; like all large loads with some variation, they also draw on ancillary services and other grid management resources.

### If incremental demand is not met with increased supply, prices and emissions will rise

As the recent Nicholas Institute report[52] points out, some amount of flexibility from data centers could significantly reduce costs and delays associated with connection and peak demand constraints from new data centers. The report estimates peak load bottlenecks could be avoided for around 100 GW of so-called "curtailment-enabled headroom" on the U.S. grid. However, even if data centers avoid consumption during the most problematic hours, they still need power the rest of the time. Absent new supply on those same grids, the extra generation available off-peak will be from more expensive, and typically dirtier, marginal generation units.

Data centers' need to draw most of their power from existing units is thus a problem for other electricity customers because absent new matching supply, it will drive up their wholesale electricity costs. It is also problematic for the data centers themselves, which frequently are tied to corporations that have carbon reduction goals which are incompatible with increased emissions from existing fossil power plants. Conversely, new supply (especially cheap and clean supply) arriving quickly enough to offset data center consumption without requiring a large amount of new grid infrastructure creates potential for "beneficial electrification[53]" where more power over the same wires reduces other consumers' costs[54].

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## Further consequences: Challenges and barriers specific to data centers

Connecting large new data center loads through the lens of three resource buckets faces three broad challenges required by all such loads. But these resource buckets also interact with the six more specific data center demand characteristics outlined in the preceding section.

### Connection challenges specific to data centers

Because the source of many connection issues—or at least more expensive upgrades—come down to a limited set of hours and circumstances, flexibility is often cited as a master key for easing or speeding up connection. But flexibility is not always as simple to implement as first imagined, and other connection challenges specific to data centers are not necessarily circumvented with a touch of flexibility.

- **Agency:** Especially for co-location data centers, the operator is stuck between wanting to be more flexible to satisfy grid constraints and the imperative to be as generic as possible in contracts with tenants to accommodate as broad a class of customers as possible. Typical quality of service and service-level agreements also act as a barrier for to tapping flexibility.[55] Intervenors in public utility cases also question whether policies for ensuring new data centers cover all their incremental costs are effective[56].
- **Clustering:** Clustering leads to many data centers on the same part of the grid, necessitating more upstream transmission upgrades, as in the Virginia case mentioned cited by NRDC, mentioned above.
- **Consumption profile:** Big swings in power demand and power quality impacts on other consumers make data centers trickier for utilities and transmission providers to study and interconnect than simple 24/7 constant loads. Standard protection schemes and the collective behavior of 60 data centers recently caused a large reliability problem in Virginia in July 2024 when these data centers all dropped off the grid at once and caused a sudden surge in excess electricity that strained grid resources.[57]
- **Flexibility:** Some data centers are not flexible at all; others could be flexible but not in a manner consistent or predictable enough to satisfy the engineers running interconnection studies. These engineers are only likely to be satisfied after adding sophisticated energy management systems and large batteries, along with the promise of judicious backup power.
- **Backup:** As mentioned, backup power could be leveraged to facilitate connection or provide so-called "bridge power"[58] for data centers that cannot wait for interconnection. Unfortunately, backup power (used either for

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flexibility or bridge power) tends to be dirty, leading to siting and local community environmental concerns.[5960]

- **Modularity:** With a modular or phased build-out, a data center may ask up front for a large enough connection to accommodate all future phases, leading to stranded asset risk if all phases do not materialize.

### Grid services challenges specific to data centers

Just as for solving connection issues, flexibility can help tamper the impact of new data centers on system-wide needs like peak capacity issues. A large overlap exists between local grid and larger grid issues with peak planning. However, as described in the prior section, flexibility is not always easy to implement or deploy in a manner which solves all challenges. Furthermore, the specific features of data centers tend to create additional challenges beyond help from simple load flexibility measures.

- **Agency:** Utilities often see new fossil resources like gas peakers as the easiest way to resolve new peak demand issues from data centers.[61] Because gas turbines are increasingly expensive, this may not be a good deal for other utility customers and may also entrench future emissions, working against many data center providers' and host states' clean power goals. Because eventual data center owner/operators tend to build where developers have prepared the ground, the fact that these developers may perceive emissions goals as secondary to "speed-to-power," and that utilities choose their own procurement path creates an agency mismatch.
- **Clustering:** The clustering of data centers tends to amplify their effects on the regional grid, with sharper surges in demand for grid services that cannot be accommodated fast enough through new resources builds.
- **Consumption profile:** While data centers don't run all the time, they plan their infrastructure for peak computing demand. This creates a knock-on effect for the bulk power system, which plans for peak power demand.
- **Flexibility:** Flexibility is not always a simple feature to implement or deploy.
- **Backup:** On-site backup power is a poor substitute for system resources because of expense as well as siting and local environmental concerns.
- **Modularity:** While the broader grid is in a good position to adjust to a phased build out of data center demand, this requires either coordination with the local utility or strong forward signals in the market to avoid disruptive demand shocks for grid services.

### Bulk electricity challenges specific to data centers

Certain subcategories here (consumption profile, flexibility, modularity) concern time domains that do not apply when considering total annual consumption.

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- **Agency:** As with grid connection and services, intermediate entities between electricity provisioners and data center owner/operators with emissions goals may not consider the environmental impacts of reliance on using spare capacity from existing marginal resources.
- **Clustering:** Clustering means more annual electricity drawn from the same grid. This creates a greater need for new supply, amplifying the problems of price and emissions increases.
- **Consumption profile:** A variable but not necessarily predictable profile for large data center loads could create new challenges for grid operators, even at off-peak times.
- **Flexibility:** Data center demand flexibility could potentially alleviate emission concerns by targeting off-peak consumption more towards time periods with lower marginal emissions. This requires an extra layer of control on top of whatever that data center might have already committed to ease grid connection and mitigate impacts on grid operational resources.
- **Backup:** Supplying too much of the actual annual electricity use from backup power creates problematic environmental impacts.

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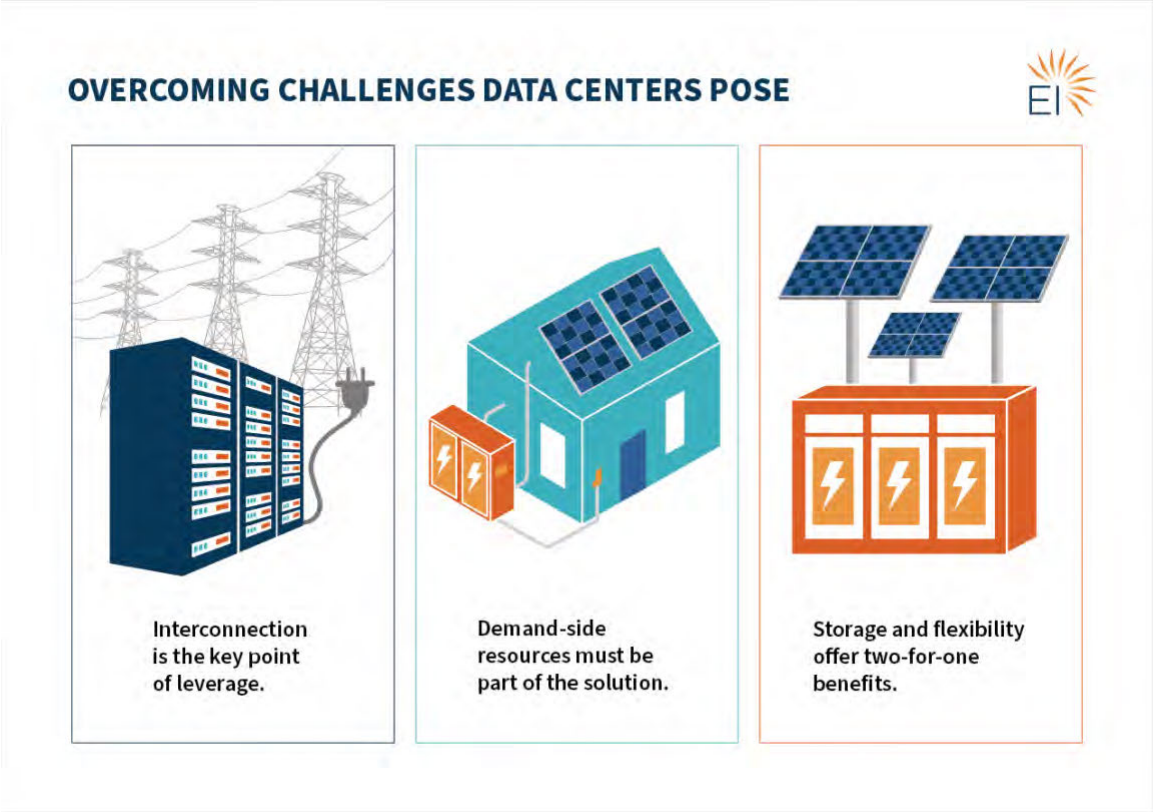
# TAKEAWAYS FOR POLICYMAKERS AND OTHER STAKEHOLDERS

*Figure 7 Three key takeaways*




Many organizations (Clean Air Task Force/Brattle,[62] GridLab,[63] NRDC,[64] the Bipartisan Policy Center,[65] and the Regulatory Assistance Project[66]) have provided detailed and useful guides for coping with the challenges of meeting new data center loads.

This section distills the key lessons from the features and challenges discussed above.

### Interconnection is the key point of leverage to influence when and how data centers join the grid

Accommodating large, dense new loads affects every grid participant, and the challenges show up at multiple scales. Geographically, they range from the substation where the data center connects to the entire interconnected system. In time, they span from sub-second transients to hours of local and bulk stress to the accumulation of annual demand.

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When issues are tied directly to a data center's load or its immediate connection, cost-causation principles are easier to apply. But at larger scales, like meeting new annual demand or rising peaks across a region, the problem is less about the nature of data centers than the pace and size of their growth. At that point, they can reasonably argue for being treated like any other customer buying power "at the pump," without special obligations.

This tension is what policymakers need to keep in mind. Interconnection is the moment of maximum leverage: not to extract unreasonable concessions, but to ensure new entrants cover the infrastructure costs they trigger, and to nudge them toward implementing solutions like flexible demand or local storage that relieve local bottlenecks and support the broader grid. Likewise, developers and customers should lean toward local fixes that speed access to the grid, improve power quality, and ease broader impacts—reducing the likelihood of being saddled with extraordinary requirements later.

### Using other demand-side resources

In one of our earlier reports on meeting the load growth challenge,[67] we pointed out the importance of using demand-side resources to meet this challenge most efficiently. Often the discussion of demand-side solutions focuses on direct measures at a data center, especially in the wake of the efficiencies revealed in the DeepSeek announcement.[68] However, data centers can meet their resource needs with other demand-side resources elsewhere on the grid. Recently, Voltus, an aggregator of distributed energy resources (DERs), announced a deal with Cloverleaf Infrastructure—a data center developer—to meet new capacity needs from data centers with market-accredited capacity from DERs.[69] This kind of transaction compensates other existing customers and thus helps accommodate the rapid rise of data center loads fairly, speedily, and equitably. Since connecting to the grid can involve mixing and matching resources to relieve bottlenecks, once a data center has invested in the flexibility and extra equipment needed to resolve local connection issues, there is no reason why more upstream connection issues, grid services bottlenecks, and the need for a large amount of annual electricity delivery cannot be resolved with demand-side solutions from other grid users.

A recent Rewiring America report proposes many of the resources to meet data center load growth could come from sponsoring household upgrades.[70] The report finds that if hyperscalers paid 50 percent of the up-front cost of installing heat pumps in the tens of millions of U.S. households that currently use inefficient electric heating, cooling, and water heating, they could free up a total 30 GW of capacity on the grid. In addition, if hyperscalers paid 30 percent of the up-front cost of rooftop solar and storage in every single-family household in the U.S., they could add 109 GW of capacity on the grid. The cost of these upgrades would be comparable to the report's estimate of $315/kW-year to build and operate a new gas power plant.

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### Storage and flexibility relieve data center challenges; they can also ease interconnection of new variable renewables

On-site prime generation solutions built around renewables and flexibility (modulating demand and using batteries) may provide cheaper, cleaner, and faster means for meeting new and existing data center demand. Because batteries are increasingly essential for buffering, backup, and power quality, they also provide a built-in solution for integrating variable renewables—offering a two-for-one advantage.

Furthermore, these renewable-plus-battery solutions can take advantage of existing surplus interconnection[71] to more quickly connect data centers to the grid in "power couples."[72]

By exploring the nuanced solutions, policymakers can avoid overcommitting to outdated firm resources and instead adopt strategies that embrace modularity, flexibility, and clean energy. Doing so will support both the digital economy's explosive growth and the clean energy transition.

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BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

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|---|---|
| Federal Power Act Section 202(c) | ) |
| Emergency Order: Tri-State | ) |
| Generation and Transmission | ) |
| Association, Platte River Power | ) |
| Authority, Salt River Project, | ) |
| PacifiCorp, and Xcel Energy | ) |

Exhibit to
Motion to Intervene and Request for Rehearing and Stay of
Public Interest Organizations

Exhibit 2-46:
R Street Institute Commentary: DOE "Zombies" Are Eating
Competitive Power Markets

REAL SOLUTIONS

# Low-Energy Fridays: DOE "Zombies" Are Eating Competitive Power Markets

BY MICHAEL GIBERSON

ISSUES: ELECTRICITY POLICY, ENERGY AND ENVIRONMENT

NOV 13, 2025

This past May, the U.S. Department of Energy (DOE) used emergency authority to stop two scheduled power plant retirements. As we explained in July, these emergency orders are not a good way to boost grid reliability. That's not the only problem, though—the DOE's emergency orders also threaten to undermine competition in regional power markets.

The case invoked Section 202(c) of the Federal Power Act, which limits most orders to just 90 days. The DOE used this law to block the coal-fired J.H. Campbell Power Plant in Michigan and two units at the gas- and oil-fired Eddystone Generation Station in Pennsylvania from retiring. When those 90-day orders expired in August, the DOE issued new orders to keep the plants online. When these orders expire later in November, the DOE is expected to order the plants to stay online for *another* 90 days. Both currently operate with a safety net: If they lose money, the law makes area consumers cover those losses. And with losses covered no matter what, the plants have little reason to run efficiently. The result isn't grid reliability—it's creeping zombification of the market.

Markets require profits *and* losses to steer investment where it's needed (and away from where it's not). When a unit can't cover its costs at market prices, it should retire. When older, inefficient plants exit, space opens on the grid and in the market for better resources to jump in. Prices may initially rise, but consumers benefit in the end as competition grinds down average costs. Serial "emergency" orders break the economic feedback loop and undermine competitive forces.

The DOE's decision to keep two fossil-fueled power plants running raised speculation that the administration would block any fossil-fueled plant from retirement. However, a New Hampshire coal unit retired in October without federal intervention. That's good, because a plant that doesn't contribute to reliability and energy supplies at a competitive price *should* retire. But the lack of clear policy heightens uncertainty.

The economic damage shows up in three places:

- **Crowding out.** When zombie power plants are ordered to stay in the market, customers are stuck with the bill from any losses. Market revenues that would support efficient resources get skimmed by units the market has already rejected. The effect is subtle but

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important: Energy market prices flatten, clean and firm resources see less upside in tight hours, and generation turnover slows.

- **Planning.** Reliability planning depends on credible schedules—retirements that can be believed, new power plants that can be counted, and rules that don't change unnecessarily. A plant yo-yoing between "retired," "ordered to run," and "maybe extended" in 90-day increments can't fit into long-run reliability plans.

- **Policy-driven uncertainty.** States and stakeholders are suing the DOE over the emergency orders because the law is being employed in a manner different from what Congress intended. The DOE has not articulated a clear policy for how they will use their authority in the future, which leaves plant owners and potential investors in the dark.

Emergency orders do have their place. If a hurricane hits, fuel freezes, or a wildfire takes out a major power line, use 202(c) for the days or weeks necessary and then stand down. Utilities regularly ask for these emergency orders when they need them. The difference with zombie plant orders is that neither the plant owners nor the grid operators responsible for reliability in their regions requested them.

Nothing in this discussion denies reality—demand for electricity is rising, interconnection queues are clogged, and grid operators face tough winters and hot summers. The way forward is in policies that make better use of the existing grid, drive economical additions to transmission infrastructure, and let market forces drive power plant entry *and* exit. Competitive power markets are not responsible for rising electricity rates; in fact, a recent study pointed to increased spending on transmission and distribution wires as key factors in driving up customer rates.

Should the DOE continue to undermine market competition, consumers may get hit with the double-whammy of rising energy costs and rising infrastructure spending. Zombification of the electricity industry is no way to support a reliable, efficient power system.

BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

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| Federal Power Act Section 202(c) | ) |
| Emergency Order: Tri-State | ) |
| Generation and Transmission | ) |
| Association, Platte River Power | ) |
| Authority, Salt River Project, | ) |
| PacifiCorp, and Xcel Energy | ) |

Exhibit to
Motion to Intervene and Request for Rehearing and Stay of
Public Interest Organizations

Exhibit 2-47:
Palgrave Handbook



# The Palgrave Handbook of International Energy Economics

*Edited by* Manfred Hafner · Giacomo Luciani

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rotating standby state through the advanced control system, and the gas turbine is quickly started with load, and the power is immediately transmitted to the power grid.

### *3.4 Location*

Coal power generation location is more restrictive compared to other technologies because coal is a solid and its transport cost is high, while its combustion efficiency is lower than for other technologies. Usually coal plants are located near coal mines and the choice of different means of transport will affect the location of the plant area as well as the size and form of the required land plot, especially for a large power plant. The transportation mode should allow for large volume, low freight, high speed, and flexibility, which will make the location of coal plant all the more difficult.

On the contrary, oil is easy to transport with multiple transportation options including by pipeline and by ship; therefore, oil-fired plants are usually located in coastal areas. A gas-fired power plant is characterized by little land occupation and is very suitable for countries and areas with dense population and scarce land resources. Compared with coal-fired power plants, gas power generation equipment is more compact and does not occupy a large area. Besides, it consumes one-third of the water needed for a coal-fired power plant.

### *3.5 Expected Service Life*

Thermal power plants are designed for an economic lifetime of 30 to 40 years, but some plants have been also used beyond their design life in certain areas. The critical components are the boiler and the turbine. The operation of thermal power generation is faced with both tangible and intangible aging processes. Tangible or physical aging refers to the equipment operating under high pressure and temperature, and bearing mechanical stress, resulting in physical and chemical changes, such as wear, creep, corrosion, and so on, gradually making the equipment unable to continue operating safely under the required design parameters. Invisible aging refers to technological progress. The advent of more efficient or less labor-intensive production equipment means that older equipment will operate under less and less economic conditions. The physical aging of some equipment (such as condenser copper pipes, heater pipes, boiler heating surface pipes, turbine blades, furnace walls, etc.) can be removed during overhaul. However, it is often the aging of these important equipment components that determines the technical and consequently economic lifetime of thermal power plants. Operating experience shows that the service life of equipment operating under 450 °C is between 40 and 50 years. For equipment operating at temperatures above 450 °C, the operating hours could even be reduced to 100,000 hours.

Both gas and steam turbines are devices that drive the rotor to rotate at high speed through high-pressure gas with high temperature and humidity.

BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

| | |
|---|---|
| Federal Power Act Section 202(c) | ) |
| Emergency Order: Tri-State | ) |
| Generation and Transmission | ) |
| Association, Platte River Power | ) |
| Authority, Salt River Project, | ) |
| PacifiCorp, and Xcel Energy | ) |

Exhibit to
Motion to Intervene and Request for Rehearing and Stay of
Public Interest Organizations

Exhibit 2-48:
IEA Report



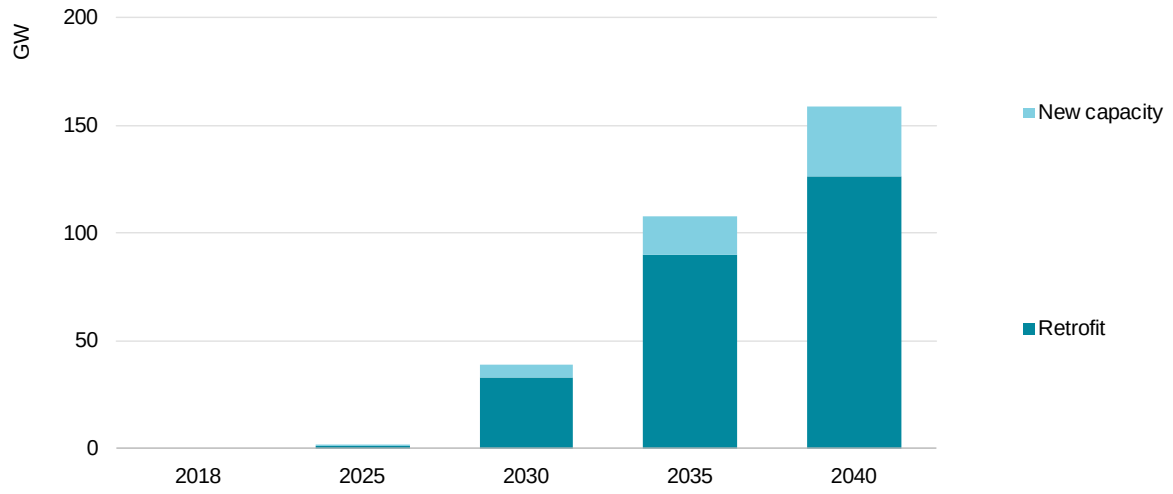
International Energy Agency

# The role of CCUS in low-carbon power systems

## Without carbon capture, meeting climate goals would ultimately mean almost eliminating the use of fossil fuels for power.

In the Sustainable Development Scenario, 120 GW of existing coal-fired capacity is retrofitted with carbon capture by 2040, accounting for some 80% of the coal plants equipped with these technologies. More than 110 GW of these retrofits are in China, representing a capital investment of around USD 160 billion. A further 10 GW are in the United States. Without carbon capture available at scale in power, coal-fired power generation, and eventually also gas-fired generation, would need to be virtually eliminated to meet long-term climate goals, with significant early retirements and potential stranding of assets.

**Figure 4** **Coal-fired power plants equipped with carbon capture in the Sustainable Development Scenario**




Source: IEA (2019), World Energy Outlook 2019.

Over 750 GW of existing coal plants reduce operations to cut emissions in this Scenario, limiting electricity production but still providing system adequacy and flexibility. About one-quarter of the existing fleet would be retired before reaching the typical 50-year lifespan. Shutdowns and reduced operating hours are likely to lead to balance sheet write-downs for some owners of existing facilities. Coal plant retirements also imply greater investment in other low-carbon sources of electricity and associated network infrastructure.

Carbon capture retrofits also play an important role for the gas-fired power plant fleet, which currently has an average age of only around 19 years. In the SDS 155 GW of natural gas-fired power plants are equipped with carbon capture, utilisation and

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BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

| | |
|---|---|
| Federal Power Act Section 202(c) | ) |
| Emergency Order: Tri-State | ) |
| Generation and Transmission | ) |
| Association, Platte River Power | ) |
| Authority, Salt River Project, | ) |
| PacifiCorp, and Xcel Energy | ) |

Exhibit to
Motion to Intervene and Request for Rehearing and Stay of
Public Interest Organizations

Exhibit 2-49:
Tri-State Revised 2020 ERP Assessment of Existing Resources

# Electric Resource Plan

## Assessment of Existing Resources

## REVISED

## June 1, 2020 Informational Filing

**for**

**Tri-State Generation and Transmission Association, Inc.**

**Submitted to:**

**Colorado Public Utilities Commission**

**August 3, 2020**

Colorado PUC E-Filings System

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## Compliance Table

| Rule | Section |
|---|---|
| 3605(c)(I)(A-E,J,K) | Owned and Leased Resources |
| 3605(c)(I)(F-G,L) | Purchased Power Resources |
| 3605(c)(I)(I) | Demand Side Management & Energy Efficiency |
| 3605(c)(I)(C,H) | Projected Annual Emissions, Capacity Factors and Availability |
| 3605(c)(II) | Benchmarking |
| 3605(c)(III) | Ancillary Service Assessment |

## Background

Pursuant to Commission Decision No. C20-0304, in Proceeding No. 19R-0408E and Rule 3605 (a)(i) of the Colorado Public Utilities Commission's Rules Regulating Electric Utilities, Tri-State Generation and Transmission Association, Inc. (Tri-State) submits the following assessment of existing resources pursuant to paragraph 3605 (c) to the Public Utilities Commission of Colorado (Commission).

## Summary

Tri-State is a wholesale cooperative electric generation and transmission association consisting of 43 Utility Member systems located across four states, operating within multiple Balancing Authorities and served by multiple Transmission Providers. Additionally, Tri-State's load is dispersed in multiple states and between the Eastern Interconnection grid and the Western Interconnection grid. Tri-State's load in the Eastern Interconnection, which primarily includes loads in Nebraska along with a small amount of northeastern Colorado load, is served by an all requirements contract with Basin Electric Power Cooperative (BEPC). Resources for serving Tri-State load in the Western Interconnection, which includes loads in Wyoming, Nebraska, Colorado and New Mexico, are a combination of company owned resources and power purchase agreements.

Figure 1 below illustrates the geographic diversity of Tri-State's load and resources along with Tri-State Merchant[1] owned transmission capacity and related transmission constraints. In the Western Interconnection, Tri-State Merchant is a network transmission customer of the following Transmission Providers:

- Tri-State Generation & Transmission Association (Tri-State Transmission)
- Public Service of Colorado (PSCo)
- Platte River Power Authority
- Western Area Power Administration (WAPA) Rocky Mountain Region Loveland Area Projects
- Black Hills Energy Colorado
- PacifiCorp

Additionally, Tri-State Merchant is a point-to-point transmission customer of many Transmission Providers in the Western Interconnection. Tri-State Merchant uses these network and point-to-point transmission rights within Western Electricity Coordinating Council (WECC) TOT capacity limits and other system constraints to schedule power from resources to loads on a day ahead and hourly basis to serve Utility Member system loads.

[1] Tri-State Merchant is the marketing arm of Tri-State Generation and Transmission Association that is responsible for planning and originations in regards to energy, capacity and transmission necessary to serve Utility Member system load along with related dispatch, scheduling and settlements activity.

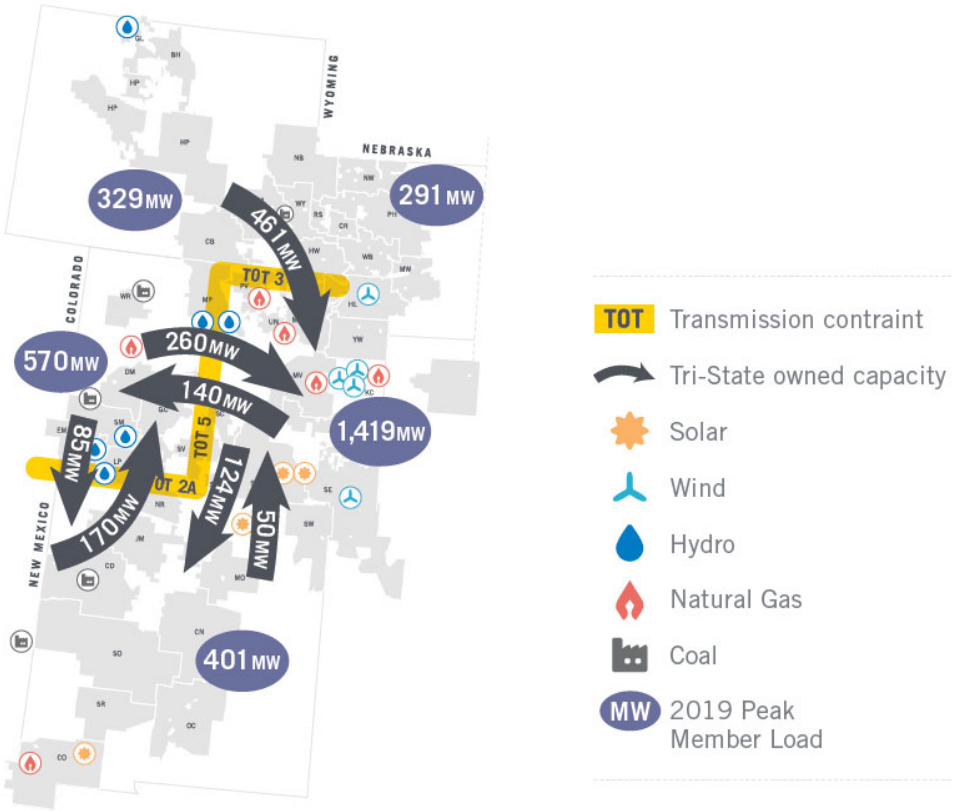


Figure 1 – Tri-State System Map

The following assessment describes existing resources both operational and contracted for at the time of this filing with appropriate detail as prescribed in 3605 (c).

# Assessment of Existing Resources

## 1. Owned & Leased Resources

**Assessment Approach**

The following is a description of Tri-State-owned and leased resources in terms of unit characteristics, emission rates and revenue requirements. Assessment excludes the following items, as Tri-State does not have any applicable resources in these categories:

- Thermal resources under contract (3605(c)(I)(A))
- Utility-owned energy storage resources (3605(c)(I)(A))
- Utility-owned thermal resources that are not in service at this time (3605(c)(I)(D))

The following assumptions and interpretations apply:

- Escalante is excluded, as it will be retired by December 31, 2020.
- Craig 1's useful life is identified as its announced retirement date. Original useful life was in the 2030s.

- Net Dependable Capacity for coal resources is the same MW value as Maximum Capacity. (3605(c)(I)(B))
- Net Dependable Capacity for gas resources varies by season and is identified by Summer and Winter Capacity MW values. Gas resources reach their maximum capacity level in the winter. (3605(c)(I)(B))
- Marginal heat rate is calculated as the average heat rate over the Resource Acquisition Period (RAP), which is identified as 2021 to 2030, for a typical dispatch.
- Fuel cost can be derived from provided heat rates for each resource and forward fuel curves for each fuel type. Tri-State does not utilize a forward fuel curve for oil, as our oil units are used for reliability events not economic dispatch and planning.
- Emissions rates are based on 2018 actuals data as provided by Tri-State Environmental; data will be refreshed as 2019 actuals are finalized and updated in the December 1, 2020 ERP filing.
- For Revenue Requirements where Tri-State has partial ownership in a resource, costs represent Tri-State's prorata share.
- There are no planned significant new investment or maintenance expenses. O&M and Capex costs are representative of necessary maintenance and improvements to maintain reliability of the resources. (3605(c)(I)(E))
- Annual capital expenses are an average of annual expenses over the Resource Planning Period of 2021 to 2040 for the life of each resource as determined by useful life or planned retirement date.
- Costs associated with the use of emissions control systems are not separately forecasted, but are instead included in overall operating and maintenance costs.
- Although not a unit level revenue requirement, Social Cost of Carbon is included in the revenue requirement tables for thermal resources as Tri-State is aware of the requirement to consider this value in its assessment of resources and resulting dispatches in relation to the ERP process. The Social Cost of Carbon is calculated as the resource carbon emission rate of each unit in tons per MWh times $46.00/ton social cost of carbon.
- Tri-State's gas fleet consists of intermediate and peaking units, which are designed for cycling; therefore, no cycling or integration costs are identified for those resources. (3605(c)(I)(J))

## Coal-Fueled Generation Resources

Craig Generating Station: Craig Station is a three-unit, 1,285 MW coal-fired electric generating facility located near Craig, Colorado. Tri-State owns a 24% interest in Craig Units 1 and 2 (Yampa Project)[2], which have nameplate ratings of 427 MW and 410 MW, respectively; a 100% interest in Craig Unit 3, which has a capacity of 448 MW; and a 49% interest in the common facilities, which serve all three units. Tri-State is the operating agent for all three units and is responsible for the daily management, administration and maintenance of the facility. The non-fuel costs associated with operating Craig units 1 and 2 are divided on a pro-rata basis among all the participants[3]. Tri-State's total share of Craig Station is 648 MW. In 2016, Tri-State announced an agreement with regulators and environmental groups to

[2] Yampa Project includes Craig 1 and Craig 2 and related common facilities.
[3] Yampa Project participants include Tri-State, Platte River Power Authority, PacifiCorp, Salt River Project and Public Service Company of Colorado.

retire Craig Unit 1 by December 31, 2025 as part of revisions to the Colorado regional haze State Implementation Plan. Tri-State has also announced that Craig Units 2 and 3 will be retired by 2030.

Laramie River Generating Station: The Laramie River Station (LRS) is a three-unit, 1,710 MW coal-fired electric generating facility located near Wheatland, Wyoming. As a participant in the Missouri Basin Power Project[4], Tri-State has a 27.1% interest (464 MW) in LRS. For operational purposes, Tri-State receives energy only from LRS 2 and 3 due to their location in the Western Interconnection. LRS 1 is scheduled solely to the Eastern Interconnection and Tri-State does not receive energy from this resource. LRS is operated by BEPC.

Springerville Unit 3: Springerville Unit 3 is a 417 MW coal-fired electric generating unit that is part of the four-unit generation station located near Springerville, Arizona. One hundred percent of Unit 3 is leased by Tri-State. Tucson Electric Power (TEP) is the plant operator for the Springerville Generating Station.

*Unit Characteristics*

| | Craig 1 | Craig 2 | Craig 3 | LRS 2 | LRS 3 | SPV3 |
|---|---|---|---|---|---|---|
| **Average Heat Rate** *(btu/kWh)* | 10,316 | 10,219 | 10,135 | 9,926 | 10,286 | 9,945 |
| **Marginal Heat Rate** *(btu/kWh)* | 10,464 | 10,509 | 10,491 | 9,878 | 10,206 | 10,168 |
| **Quick Start Capable** *(Yes/No)* | No | No | No | No | No | No |
| **Minimum Operating Level** *(MW)* | 31 | 31 | 130 | 94 | 94 | 109 |
| **Useful Life** | 12/31/2025 | 12/31/2039 | 12/31/2044 | 12/31/2041 | 12/31/2042 | 12/31/2066 |

*Emission Rates*

| *lbs. per MWH* | $CO_2$ | $SO_2$ | NOx | PM | HG |
|---|---|---|---|---|---|
| **Craig 1** | 2319 | 0.378 | 2.771 | 0.042 | 0.00001700 |
| **Craig 2** | 2350 | 0.345 | 0.672 | 0.047 | 0.00001400 |
| **Craig 3** | 2090 | 1.308 | 2.248 | 0.061 | 0.00007800 |
| **LRS 2** | 2203 | 1.101 | 2.331 | 0.095 | 0.00004110 |
| **LRS 3** | 2407 | 1.823 | 2.410 | 0.177 | 0.00004680 |
| **SPV3** | 2139 | 0.838 | 0.787 | 0.031 | 0.00001600 |

*CO2, SO2, and NOx are lbs. per net MWh; PM and HG are lbs. per Gross MWh*

*Revenue Requirements*

| | Fixed O&M Annual *($000s)* | Variable O&M *($/MWH)* | CapEx Costs Annual *($000s)* | Social Cost of Carbon *($/MWh)* | Integration & Cycling Costs *($/MWh)* | Fuel Curve *(See Figure 2)* |
|---|---|---|---|---|---|---|
| **Craig 1** | [redacted] | | ~$500 | $53.34 | $0.129 | CRG (Inc) |

[4] The Missouri Basin Power Project is the Laramie River Electric Generating Station and Transmission System located in Wyoming. Its participants include Tri-State, BEPC, the Western Minnesota Municipal Power Agency (Missouri River Energy Services), the Lincoln Electric System, and the Wyoming Municipal Power Agency.

| | | | | | |
|---|---|---|---|---|---|
| **Craig 2** | [redacted] | ~$500 | $54.05 | $0.131 | CRG (Inc) |
| **Craig 3** | | ~$3,000 | $48.07 | $0.124 | CRG (Inc) |
| **LRS 2** | | ~$1,500 | $50.67 | $0.111 | LRSG |
| **LRS 3** | | ~$1,500 | $55.36 | $0.108 | LRSG |

Tri-State forward coal prices change annually. Figure 2 below shows the current coal forward curve inclusive of inflation. CRG (All-In), LRSG and SPV3 values are all inclusive costs of fuel. CRG (Inc) is the Craig coal cost as an incremental value.



**Figure 2 – Coal Price Curve**

## Gas & Oil-Fueled Generation Resources

Below capacity ratings are composite annual MW rating.

J.M. Shafer Generating Station: J.M. Shafer is a 272 MW natural gas-fueled, combined-cycle power plant located north of Fort Lupton, Colorado. The facility is a wholly-owned Tri-State subsidiary, Thermo Cogeneration Partnership, L.P., and operated by Tri-State.

Rifle Generating Station: Rifle Station is an 81 MW, natural gas-fueled combined-cycle power plant located near Rifle, Colorado. The facility is wholly-owned and operated by Tri-State.

Limon Generating Station: Limon Station is a two-unit, 140 MW, natural gas and oil-fired simple cycle combustion turbine facility located near Limon, Colorado. It is wholly-owned and operated by Tri-State.

Knutson Generating Station: Knutson Station is a two-unit, 140 MW, natural gas and oil-fired simple cycle combustion turbine facility located near Brighton, Colorado. It is wholly-owned and operated by Tri-State.

Pyramid Generating Station: Pyramid Station is a four-unit, 160 MW, natural gas and oil-fired simple cycle combustion turbine facility located near Lordsburg, New Mexico. It is wholly-owned and operated by Tri-State.

Burlington Generating Station: Burlington Station is a two-unit, 110 MW, oil-fired simple cycle combustion turbine facility located in Burlington, Colorado. It is wholly-owned and operated by Tri-State.

*Unit Characteristics*

| | JM Shafer | Rifle | Limon | Knutson | Pyramid | Burlington |
|---|---|---|---|---|---|---|
| **Summer Capacity** *(MW)* | 272 | 72 | 67 | 67 | 40 | 48 |
| **Winter Capacity** *(MW)* | 272 | 84 | 74 | 74 | 40 | 60 |
| **Fuel type** | NG | NG | NG/FO | NG/FO | NG/FO | FO |
| **Average Heat Rate** *(btu/kWh)* | 9,322 | 10,321 | 11,449 | 11,449 | 9,742 | 14,000 |
| **Marginal Heat Rate** *(btu/kWh)* | 9,282 | 10,965 | 10,852 | 10,835 | 9,985 | -[5] |
| **Quick Start Capable** *(Yes/No)* | No | No | Yes | No | Yes | Yes |
| **Minimum Operating Level** *(MW)* | 41 | 22 | 40 | 40 | 25 | 25 |
| **Useful Life** | 12/31/2047 | 12/31/2028 | 12/31/2048 | 12/31/2048 | 12/31/2049 | 12/31/2037 |

NG = Natural Gas; FO = Fuel Oil

*Emission Rates*

| ***lbs. per MWH*** | **$CO_2$** | **$SO_2$** | **NOx** | **PM** | **HG** |
|---|---|---|---|---|---|
| **JM Shafer** | 981 | 0.008 | 0.747 | 0.080 | n/a |
| **Rifle** | 1206 | 0.001 | 2.611 | 0.239 | n/a |
| **Limon** | 1495 | 0.008 | 0.378 | 0.062 | n/a |
| **Knutson** | 1502 | 0.009 | 0.341 | 0.124 | n/a |
| **Pyramid** | 1240 | 0.012 | 1.223 | 0.070 | n/a |
| **Burlington** | 2149 | 0.194 | 12.383 | 0.158 | n/a |

*CO2, SO2, and NOx are lbs. per net MWh; PM is lbs. per Gross MWh*

*Revenue Requirements*

| | **Fixed O&M Annual** *($000s)* | **Variable O&M** *($/MWH)* | **CapEx Costs Annual** *($000s)* | **Social Cost of Carbon** *($/MWh)* | **Fuel Curve** *(See Figure 3)* |
|---|---|---|---|---|---|
| **JM Shafer** | [redacted] | | ~$1,500 | $22.56 | CIG |
| **Rifle** | | | ~$200 | $27.74 | CIG |
| **Limon** | | | ~$275 | $34.39 | CIG |
| **Knutson** | | | ~$400 | $34.55 | CIG |

[5] Burlington did not dispatch over the RAP

| | | | | |
|---|---|---|---|---|
| **Pyramid** | [redacted] | ~$300 | $28.52 | WAHA |
| **Burlington** | | ~$450 | $49.42 | N/A |

Tri-State forward gas prices change monthly. Figure 3 below shows the current gas forward curve without inflation. Additional transport costs apply.



**Figure 3 – Forward Gas Curve**

**Third Party Assessment**

In preparation for Tri-State's 2020 Colorado Electric Resource Plan (ERP) and Western Area Power Administration's Integrated Resource Plan (IRP) processes, Tri-State engaged Black & Veatch (B&V) to assist Tri-State with this assessment of existing resources by reviewing the following items for owned and leased resources:

- Heat Rates
- VOM
- Fixed costs
- Emissions
- Capacity Factors

Additionally, B&V reviewed these items to the extent applicable in regards to the Basin Contract Rate of Delivery (CROD) Western Interconnection contract, Basin Electrically East contract and Renewable Power Agreements[6] .

[6] More detail on these contracts can be found in the Purchase Power Resources section.

Specific areas of recommended change were as follows:

| B&V Recommendation | Conclusion |
|---|---|
| Increase Burlington Heat Rate | Adjustment made to heat rate curve |
| Change Availability Factor of Combined Cycle resources to 90% | Tri-State will make accommodations in modeling to reflect these changes. |
| Change Availability Factor of Combustion Turbine dual fuel resources to 96% | Tri-State will make accommodations in modeling to reflect these changes. |
| Change Availability Factor of Combustion Turbine oil resources to 98% | Tri-State will make accommodations in modeling to reflect these changes. |
| Reduction in Rifle Fixed Costs | Rifle fixed costs are based on historical data. Tri-State will continue to monitor Rifle fixed costs and adjust as necessary. |
| Reduction to Burlington and Rifle NOx emission rate | Burlington and Rifle NOx emissions are based on historical data. There are conditions specific to these units that make their emissions rates higher than industry averages, so this will remain at the higher level. |
| Increase to Rifle and Shafer $SO_2$ emission rates | Rifle and Shafer $SO_2$ emission rates are based on historical data. Tri-State will continue to monitor $SO_2$ for these units and update as needed. |
| Decrease of availability factor and related increase in forced outage factor for all gas units | Tri-State is reviewing this feedback and will take into consideration current and expected operation of gas and oil units and modify as determined to be necessary. |

The Black & Veatch evaluation detail can be found in Appendix A Black & Veatch Report on Review of Existing Resources.

## 2. Projected Annual Emissions, Energy, Capacity Factors and Availability

This section contains representative scenario data for emissions, energy, capacity factors and availability during the RAP.

***Base Case Scenario (typical dispatch):***

The following values are based on a "typical" dispatch plan representative of Tri-State's current operations and announced resource additions and retirements. Expansion plan resources are required to support this dispatch. Greenhouse gas reduction requirements in the state of Colorado are not reflected in these numbers. Tri-State anticipates that an appropriate greenhouse gas reduction strategy will be developed in conjunction with the presently ongoing proceedings of the Colorado Air Quality Control Commission (AQCC) and as part of the ERP process.[7]

[7] The retirement of Craig 2 at the end of 2028 as illustrated in this dispatch was one of several possible scenarios. As of July 2020, the Yampa participants have announced a retirement date for Craig 2 of September 30, 2028.

The below calculated emissions are based on generation by resource from the plan and applicable historical emission rates as identified in the Owned & Leased Resources section or Purchased Power Resource section.

*Projected $CO_2$ Emissions (000s of Short Tons*)

| $CO_2$ | 2021 | 2022 | 2023 | 2024 | 2025 | 2026 | 2027 | 2028 | 2029 | 2030 |
|---|---|---|---|---|---|---|---|---|---|---|
| **Craig 1** | 829 | 829 | 829 | 829 | 477 | 0 | 0 | 0 | 0 | 0 |
| **Craig 2** | 941 | 947 | 841 | 896 | 495 | 552 | 623 | 569 | 0 | 0 |
| **Craig 3** | 3357 | 3779 | 3352 | 3164 | 1851 | 2339 | 2156 | 2414 | 2955 | 0 |
| **LRS 2** | 2116 | 1847 | 2104 | 1935 | 1826 | 2116 | 2106 | 1872 | 2021 | 2031 |
| **LRS 3** | 2246 | 2144 | 1986 | 1933 | 2280 | 2039 | 2283 | 2281 | 1955 | 2198 |
| **SPV3** | 2025 | 1697 | 1920 | 1824 | 2292 | 2486 | 2583 | 2538 | 2648 | 2709 |
| **JM Shafer** | 376 | 285 | 46 | 142 | 226 | 182 | 145 | 104 | 111 | 125 |
| **Rifle** | 1 | 0 | 16 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **Limon** | 10 | 5 | 116 | 5 | 16 | 4 | 1 | 0 | 0 | 0 |
| **Knutson** | 23 | 16 | 137 | 6 | 14 | 2 | 1 | 0 | 0 | 0 |
| **Pyramid** | 11 | 34 | 8 | 5 | 90 | 90 | 84 | 83 | 46 | 37 |
| **Burlington** | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **Basin CROD Western Interconnection** | 1815 | 1815 | 1815 | 1821 | 1815 | 1815 | 1815 | 1821 | 1815 | 1815 |
| **Basin Electrically East** | 469 | 472 | 476 | 479 | 482 | 486 | 489 | 492 | 496 | 499 |

*Projected $SO_2$ Emission (Short Tons)*

| $SO_2$ | 2021 | 2022 | 2023 | 2024 | 2025 | 2026 | 2027 | 2028 | 2029 | 2030 |
|---|---|---|---|---|---|---|---|---|---|---|
| **Craig 1** | 135 | 135 | 135 | 135 | 78 | 0 | 0 | 0 | 0 | 0 |
| **Craig 2** | 138 | 139 | 123 | 132 | 73 | 81 | 91 | 84 | 0 | 0 |
| **Craig 3** | 2101 | 2365 | 2098 | 1980 | 1159 | 1464 | 1350 | 1511 | 1850 | 0 |
| **LRS 2** | 1058 | 923 | 1052 | 967 | 913 | 1058 | 1053 | 935 | 1010 | 1015 |
| **LRS 3** | 1701 | 1624 | 1504 | 1464 | 1727 | 1544 | 1729 | 1727 | 1480 | 1664 |
| **SPV3** | 793 | 665 | 752 | 714 | 898 | 974 | 1012 | 994 | 1038 | 1061 |
| **JM Shafer** | 2.99 | 2.27 | 0.36 | 1.13 | 1.80 | 1.45 | 1.15 | 0.82 | 0.88 | 1.00 |
| **Rifle** | 0.00 | 0.00 | 0.01 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| **Limon** | 0.05 | 0.03 | 0.62 | 0.02 | 0.09 | 0.02 | 0.01 | 0.00 | 0.00 | 0.00 |
| **Knutson** | 0.14 | 0.10 | 0.83 | 0.04 | 0.09 | 0.01 | 0.01 | 0.00 | 0.00 | 0.00 |
| **Pyramid** | 0.11 | 0.33 | 0.08 | 0.04 | 0.88 | 0.87 | 0.82 | 0.81 | 0.45 | 0.36 |
| **Burlington** | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| **Basin CROD Western Interconnection** | 1151 | 1151 | 1151 | 1155 | 1151 | 1151 | 1151 | 1155 | 1151 | 1151 |
| **Basin Electrically East** | 530 | 534 | 537 | 541 | 545 | 548 | 552 | 556 | 560 | 563 |

*Projected NOx Emissions (Short Tons)*

| NOx | 2021 | 2022 | 2023 | 2024 | 2025 | 2026 | 2027 | 2028 | 2029 | 2030 |
|---|---|---|---|---|---|---|---|---|---|---|
| **Craig 1** | 990 | 990 | 991 | 991 | 570 | 0 | 0 | 0 | 0 | 0 |
| **Craig 2** | 269 | 271 | 240 | 256 | 142 | 158 | 178 | 163 | 0 | 0 |
| **Craig 3** | 3611 | 4064 | 3605 | 3404 | 1991 | 2516 | 2319 | 2596 | 3179 | 0 |
| **LRS 2** | 2239 | 1954 | 2226 | 2047 | 1932 | 2239 | 2228 | 1981 | 2138 | 2149 |
| **LRS 3** | 2249 | 2147 | 1989 | 1936 | 2283 | 2042 | 2286 | 2283 | 1957 | 2200 |
| **SPV3** | 745 | 624 | 706 | 671 | 843 | 915 | 950 | 934 | 974 | 997 |
| **JM Shafer** | 287 | 217 | 35 | 108 | 172 | 139 | 110 | 79 | 84 | 95 |
| **Rifle** | 3 | 0 | 34 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **Limon** | 2 | 1 | 29 | 1 | 4 | 1 | 0 | 0 | 0 | 0 |
| **Knutson** | 5 | 4 | 31 | 1 | 3 | 1 | 0 | 0 | 0 | 0 |
| **Pyramid** | 11 | 34 | 8 | 4 | 89 | 88 | 83 | 82 | 45 | 37 |
| **Burlington** | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **Basin CROD Western Interconnection** | 1867 | 1867 | 1867 | 1872 | 1867 | 1867 | 1867 | 1872 | 1867 | 1867 |
| **Basin Electrically East** | 378 | 381 | 384 | 387 | 389 | 392 | 394 | 397 | 400 | 402 |

*Projected Particulate Matter Emissions (Short Tons)*

| PM | 2021 | 2022 | 2023 | 2024 | 2025 | 2026 | 2027 | 2028 | 2029 | 2030 |
|---|---|---|---|---|---|---|---|---|---|---|
| **Craig 1** | 16 | 16 | 16 | 16 | 9 | 0 | 0 | 0 | 0 | 0 |
| **Craig 2** | 20 | 20 | 18 | 19 | 11 | 12 | 13 | 12 | 0 | 0 |
| **Craig 3** | 106 | 120 | 106 | 100 | 59 | 74 | 68 | 76 | 94 | 0 |
| **LRS 2** | 98 | 86 | 98 | 90 | 85 | 99 | 98 | 87 | 94 | 95 |
| **LRS 3** | 178 | 170 | 157 | 153 | 180 | 161 | 181 | 180 | 155 | 174 |
| **SPV3** | 32 | 26 | 30 | 28 | 36 | 39 | 40 | 39 | 41 | 42 |
| **JM Shafer** | 31 | 24 | 4 | 12 | 19 | 15 | 12 | 9 | 9 | 10 |
| **Rifle** | 0.26 | 0.00 | 3.13 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| **Limon** | 0.42 | 0.21 | 4.99 | 0.20 | 0.71 | 0.15 | 0.05 | 0.00 | 0.00 | 0.00 |
| **Knutson** | 1.94 | 1.32 | 11.37 | 0.51 | 1.17 | 0.20 | 0.10 | 0.00 | 0.00 | 0.00 |
| **Pyramid** | 0.62 | 1.94 | 0.46 | 0.26 | 5.13 | 5.12 | 4.79 | 4.73 | 2.61 | 2.12 |
| **Burlington** | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| **Basin CROD Western Interconnection** | 107 | 107 | 107 | 108 | 107 | 107 | 107 | 108 | 107 | 107 |
| **Basin Electrically East** | UA | UA | UA | UA | UA | UA | UA | UA | UA | UA |

UA = Unavailable[8]

[8] Data was not available for this sub region for particulate matter emissions.

*Projected Mercury Emissions (Short Tons)*

| hg | 2021 | 2022 | 2023 | 2024 | 2025 | 2026 | 2027 | 2028 | 2029 | 2030 |
|---|---|---|---|---|---|---|---|---|---|---|
| **Craig 1** | 0.007 | 0.007 | 0.007 | 0.007 | 0.004 | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 |
| **Craig 2** | 0.006 | 0.006 | 0.005 | 0.006 | 0.003 | 0.004 | 0.004 | 0.004 | 0.000 | 0.000 |
| **Craig 3** | 0.135 | 0.152 | 0.135 | 0.127 | 0.074 | 0.094 | 0.087 | 0.097 | 0.119 | 0.000 |
| **LRS 2** | 0.042 | 0.037 | 0.042 | 0.039 | 0.037 | 0.042 | 0.042 | 0.038 | 0.041 | 0.041 |
| **LRS 3** | 0.047 | 0.045 | 0.042 | 0.040 | 0.048 | 0.043 | 0.048 | 0.048 | 0.041 | 0.046 |
| **SPV3** | 0.016 | 0.014 | 0.016 | 0.015 | 0.019 | 0.020 | 0.021 | 0.021 | 0.022 | 0.022 |
| **JM Shafer** | N/A | N/A | N/A | N/A | N/A | N/A | N/A | N/A | N/A | N/A |
| **Rifle** | N/A | N/A | N/A | N/A | N/A | N/A | N/A | N/A | N/A | N/A |
| **Limon** | N/A | N/A | N/A | N/A | N/A | N/A | N/A | N/A | N/A | N/A |
| **Knutson** | N/A | N/A | N/A | N/A | N/A | N/A | N/A | N/A | N/A | N/A |
| **Pyramid** | N/A | N/A | N/A | N/A | N/A | N/A | N/A | N/A | N/A | N/A |
| **Burlington** | N/A | N/A | N/A | N/A | N/A | N/A | N/A | N/A | N/A | N/A |
| **Basin CROD Western Interconnection** | 0.035 | 0.035 | 0.035 | 0.035 | 0.035 | 0.035 | 0.035 | 0.035 | 0.035 | 0.035 |
| **Basin Electrically East** | UA | UA | UA | UA | UA | UA | UA | UA | UA | UA |

UA = Unavailable[9]

*Projected Basin Contract Energy & Demand*

Basin CROD Western Interconnection contract energy profile is a set hourly profile identified by point of delivery. Stegall West 230KV Bus is located in Nebraska. AU 230KV and Story 230KV busses are located in Colorado. Figures 4 and 5 below show the hourly profiles by point of delivery for each month:

POINT OF DELIVERY: STEGALL WEST 230KV BUS

| Month\HE | 1 | 2 | 3 | 4 | 5 | 6 | 7 | 8 | 9 | 10 | 11 | 12 | 13 | 14 | 15 | 16 | 17 | 18 | 19 | 20 | 21 | 22 | 23 | 24 | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| JAN | 73 | 71 | 72 | 71 | 74 | 75 | 84 | 92 | 91 | 88 | 86 | 85 | 82 | 81 | 79 | 80 | 86 | 94 | 97 | 95 | 94 | 90 | 85 | 75 | 2,000 |
| FEB | 73 | 72 | 72 | 72 | 74 | 81 | 85 | 91 | 90 | 89 | 88 | 86 | 83 | 82 | 81 | 81 | 85 | 89 | 97 | 96 | 94 | 91 | 85 | 74 | 2,011 |
| MAR | 69 | 67 | 68 | 68 | 72 | 76 | 83 | 82 | 82 | 81 | 80 | 77 | 75 | 75 | 74 | 74 | 75 | 79 | 84 | 84 | 84 | 80 | 74 | 69 | 1,832 |
| APR | 48 | 46 | 46 | 46 | 47 | 51 | 56 | 57 | 58 | 58 | 58 | 55 | 55 | 54 | 54 | 54 | 55 | 56 | 58 | 59 | 60 | 58 | 53 | 49 | 1,291 |
| MAY | 54 | 52 | 51 | 51 | 52 | 55 | 61 | 63 | 65 | 65 | 65 | 65 | 65 | 65 | 65 | 65 | 67 | 67 | 67 | 68 | 68 | 67 | 63 | 58 | 1,484 |
| JUN | 80 | 75 | 73 | 72 | 73 | 76 | 81 | 93 | 98 | 100 | 102 | 105 | 105 | 106 | 106 | 107 | 107 | 108 | 107 | 108 | 107 | 107 | 100 | 88 | 2,284 |
| JUL | 89 | 85 | 84 | 83 | 83 | 84 | 88 | 99 | 104 | 108 | 112 | 114 | 115 | 117 | 118 | 119 | 119 | 119 | 118 | 118 | 115 | 115 | 107 | 94 | 2,507 |
| AUG | 88 | 85 | 84 | 83 | 83 | 85 | 90 | 99 | 104 | 107 | 110 | 112 | 113 | 114 | 115 | 117 | 117 | 117 | 117 | 117 | 117 | 113 | 104 | 92 | 2,483 |
| SEP | 54 | 53 | 52 | 51 | 52 | 55 | 61 | 70 | 71 | 73 | 73 | 74 | 74 | 74 | 76 | 76 | 76 | 78 | 79 | 81 | 81 | 76 | 69 | 56 | 1,635 |
| OCT | 55 | 52 | 51 | 51 | 52 | 55 | 60 | 69 | 71 | 72 | 72 | 70 | 68 | 68 | 69 | 70 | 72 | 73 | 73 | 73 | 73 | 70 | 67 | 55 | 1,561 |
| NOV | 67 | 67 | 67 | 67 | 70 | 74 | 78 | 81 | 81 | 82 | 80 | 77 | 76 | 75 | 74 | 76 | 80 | 85 | 86 | 85 | 84 | 80 | 75 | 70 | 1,837 |
| DEC | 72 | 72 | 72 | 72 | 73 | 76 | 84 | 90 | 90 | 89 | 87 | 85 | 83 | 81 | 80 | 87 | 93 | 99 | 100 | 99 | 97 | 94 | 87 | 76 | 2,038 |

Amounts shown in MW, hours shown are Hour-Ending and in Mountain Standard Time

Figure 4 – Basin CROD Western Interconnection Stegall West 230KV Bus Hourly Profile

[9] Data was not available for this sub region for mercury emissions.

POINT OF DELIVERY: AULT 230KV and STORY 230KV BUSSES

| Month\HE | 1 | 2 | 3 | 4 | 5 | 6 | 7 | 8 | 9 | 10 | 11 | 12 | 13 | 14 | 15 | 16 | 17 | 18 | 19 | 20 | 21 | 22 | 23 | 24 | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| JAN | 92 | 90 | 90 | 90 | 93 | 95 | 105 | 115 | 114 | 111 | 109 | 107 | 103 | 102 | 99 | 100 | 108 | 118 | 122 | 119 | 118 | 114 | 106 | 95 | 2,515 |
| FEB | 91 | 90 | 90 | 90 | 93 | 102 | 107 | 114 | 114 | 112 | 110 | 108 | 104 | 103 | 102 | 102 | 106 | 112 | 122 | 121 | 119 | 114 | 107 | 93 | 2,526 |
| MAR | 86 | 85 | 85 | 86 | 90 | 96 | 104 | 104 | 104 | 102 | 100 | 96 | 94 | 94 | 94 | 94 | 94 | 100 | 105 | 106 | 105 | 100 | 93 | 87 | 2,304 |
| APR | 60 | 58 | 57 | 57 | 59 | 64 | 70 | 72 | 72 | 72 | 72 | 70 | 69 | 68 | 67 | 67 | 69 | 71 | 72 | 73 | 75 | 73 | 66 | 61 | 1,614 |
| MAY | 67 | 65 | 64 | 64 | 65 | 70 | 76 | 80 | 81 | 82 | 82 | 82 | 82 | 82 | 82 | 82 | 85 | 85 | 85 | 85 | 85 | 84 | 80 | 72 | 1,867 |
| JUN | 100 | 95 | 92 | 92 | 92 | 96 | 102 | 118 | 123 | 126 | 130 | 131 | 132 | 133 | 133 | 135 | 136 | 136 | 136 | 136 | 136 | 134 | 126 | 110 | 2,880 |
| JUL | 111 | 107 | 106 | 104 | 104 | 106 | 110 | 123 | 130 | 135 | 140 | 143 | 145 | 146 | 148 | 149 | 149 | 149 | 148 | 148 | 145 | 144 | 135 | 117 | 3,142 |
| AUG | 110 | 107 | 106 | 104 | 105 | 107 | 111 | 124 | 129 | 135 | 137 | 140 | 142 | 143 | 145 | 146 | 146 | 146 | 146 | 146 | 146 | 140 | 130 | 115 | 3,106 |
| SEP | 68 | 66 | 64 | 64 | 65 | 69 | 76 | 88 | 90 | 91 | 92 | 93 | 93 | 93 | 95 | 95 | 96 | 98 | 98 | 102 | 102 | 95 | 85 | 70 | 2,048 |
| OCT | 68 | 65 | 64 | 64 | 65 | 69 | 76 | 86 | 89 | 90 | 90 | 88 | 85 | 85 | 86 | 88 | 90 | 92 | 92 | 92 | 91 | 88 | 84 | 69 | 1,956 |
| NOV | 84 | 83 | 83 | 83 | 87 | 93 | 98 | 102 | 102 | 102 | 100 | 97 | 95 | 93 | 93 | 96 | 99 | 106 | 108 | 106 | 104 | 100 | 94 | 87 | 2,295 |
| DEC | 90 | 90 | 89 | 89 | 91 | 96 | 105 | 113 | 113 | 111 | 108 | 106 | 103 | 102 | 100 | 108 | 117 | 123 | 125 | 124 | 122 | 118 | 109 | 95 | 2,547 |

**Amounts shown in MW, hours shown are Hour-Ending and in Mountain Standard Time**

**Figure 5 – Basin CROD Western Interconnection AU 230KV and STORY 230KV busses Hourly Profile**

Basin Electrically East contract has an energy and demand profile based on forecasted Electrically East (Nebraska and Colorado) load, as this is a full requirements contract. The load served by this full requirements contract is located in the Eastern Interconnection primarily in the state of Nebraska with a small amount of Colorado load in the far northeastern portion of Colorado. On an average annual basis, ~15% of this purchase serves Colorado. The balance of this purchase serves load in Nebraska.

Hourly Profiles for the Basin Electrically East contract vary by season and are heavily impacted by irrigation. Figure 6 shows a typical hourly profile in a given day for the Irrigation and Non-Irrigation seasons. As shown by the orange line in the graph the hourly load during non-irrigation season barely exceeds 50 MW with a sharp morning peak, while the hourly load during irrigation season (yellow line) has a sustained daytime peak closer to ~280MW.

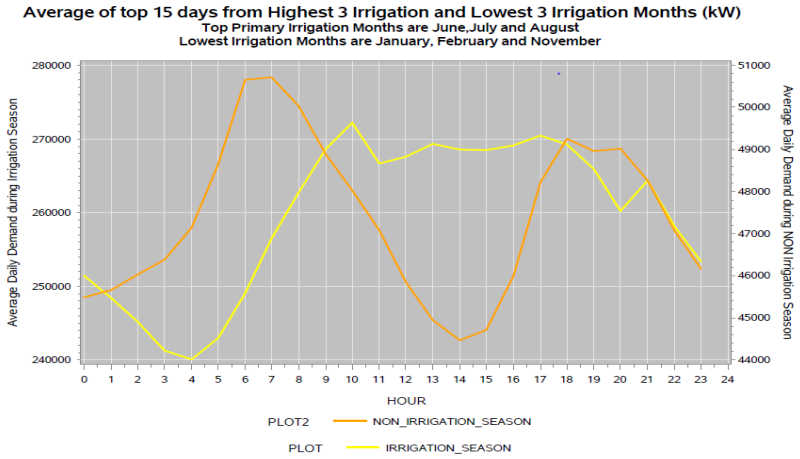


Figure 6 – Basin Electrically East Irrigation and Non-Irrigation Seasons Demand Profiles

Below is a snapshot of historical energy and demand for the Basin Electrically East contract by month:

| Year | Data/UOM | Jan | Feb | Mar | Apr | May | Jun | Jul | Aug | Sep | Oct | Nov | Dec |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 2018 | Energy (GWh) | 38 | 35 | 36 | 37 | 38 | 72 | 129 | 138 | 59 | 28 | 28 | 30 |
| 2018 | Demand (MW-Mo) | 76 | 76 | 62 | 64 | 88 | 191 | 335 | 269 | 126 | 55 | 49 | 53 |
| 2019 | Energy (GWh) | 29 | 29 | 27 | 23 | 35 | 45 | 137 | 117 | 60 | 24 | 29 | 29 |
| 2019 | Demand (MW-Mo) | 52 | 54 | 57 | 55 | 73 | 155 | 305 | 255 | 208 | 48 | 51 | 47 |

Annual Projected Energy and Demand by Contract

| Energy (GWh) | 2021 | 2022 | 2023 | 2024 | 2025 | 2026 | 2027 | 2028 | 2029 | 2030 |
|---|---|---|---|---|---|---|---|---|---|---|
| **Basin CROD Western Interconnection**[10] | 1575 | 1575 | 1575 | 1580 | 1575 | 1575 | 1575 | 1580 | 1575 | 1575 |
| **Basin Electrically East** [11] | 757 | 762 | 767 | 773 | 778 | 783 | 788 | 795 | 800 | 805 |

| Annual Demand (Sum of MW-Mo) | 2021 | 2022 | 2023 | 2024 | 2025 | 2026 | 2027 | 2028 | 2029 | 2030 |
|---|---|---|---|---|---|---|---|---|---|---|
| **Basin CROD Western Interconnection** | 2458 | 2458 | 2458 | 2458 | 2458 | 2458 | 2458 | 2458 | 2458 | 2458 |
| **Basin Electrically East** | 1671 | 1683 | 1694 | 1705 | 1716 | 1727 | 1739 | 1751 | 1762 | 1773 |

*Projected WAPA Contracts – Loveland Area Projects (LAP) and Colorado River Storage Projects (CRSP) Energy & Demand*

LAP and CRSP contracts provide a set amount of energy delivered to each sub region by month. Additionally, an hourly minimum and maximum MW take is provided for each sub region by month. Tri-State is required to schedule on a two-day ahead basis the hydro in each sub region by "dispatching" the energy within the hourly minimum and maximum ranges.

Annual Projected Energy and Demand by Contract

| Energy (GWh) | 2021 | 2022 | 2023 | 2024 | 2025 | 2026 | 2027 | 2028 | 2029 | 2030 |
|---|---|---|---|---|---|---|---|---|---|---|
| **CRSP Total** | 1424 | 1424 | 1424 | 1424 | 1424 | 1424 | 1424 | 1424 | 1424 | 1424 |
| **Colorado Deliveries** | 930 | 930 | 930 | 930 | 930 | 930 | 930 | 930 | 930 | 930 |
| **New Mexico Deliveries** | 494 | 494 | 494 | 494 | 494 | 494 | 494 | 494 | 494 | 494 |

[10] Energy is delivered to Colorado and Wyoming.

[11] ~15% of this purchase serves Colorado. Balance of purchase serves load in Nebraska.

| | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|
| **LAP Total** | 900 | 900 | 900 | 900 | 900 | 900 | 900 | 900 | 900 | 900 |
| **Colorado/Wyoming Deliveries** | 711 | 711 | 711 | 711 | 711 | 711 | 711 | 711 | 711 | 711 |
| **Nebraska Deliveries** | 189 | 189 | 189 | 189 | 189 | 189 | 189 | 189 | 189 | 189 |

| **Annual Demand [12] (Sum of MW-Mo)** | **2021** | **2022** | **2023** | **2024** | **2025** | **2026** | **2027** | **2028** | **2029** | **2030** |
|---|---|---|---|---|---|---|---|---|---|---|
| **CRSP Total** | 4807 | 4807 | 4807 | 4807 | 4807 | 4807 | 4807 | 4807 | 4807 | 4807 |
| **Colorado Deliveries** | 3105 | 3105 | 3105 | 3105 | 3105 | 3105 | 3105 | 3105 | 3105 | 3105 |
| **New Mexico Deliveries** | 1702 | 1702 | 1702 | 1702 | 1702 | 1702 | 1702 | 1702 | 1702 | 1702 |
| **LAP Total** | 3823 | 3823 | 3823 | 3823 | 3823 | 3823 | 3823 | 3823 | 3823 | 3823 |
| **Colorado/Wyoming Deliveries** | 3029 | 3029 | 3029 | 3029 | 3029 | 3029 | 3029 | 3029 | 3029 | 3029 |
| **Nebraska Deliveries** | 794 | 794 | 794 | 794 | 794 | 794 | 794 | 794 | 794 | 794 |

*Projected Annual Capacity Factors for Thermal Resources*

| | **2021** | **2022** | **2023** | **2024** | **2025** | **2026** | **2027** | **2028** | **2029** | **2030** |
|---|---|---|---|---|---|---|---|---|---|---|
| **Craig 1** | 80% | 80% | 80% | 80% | 46% | 0% | 0% | 0% | 0% | 0% |
| **Craig 2** | 93% | 94% | 83% | 89% | 49% | 55% | 62% | 56% | 0% | 0% |
| **Craig 3** | 82% | 92% | 82% | 77% | 45% | 57% | 53% | 59% | 72% | 0% |
| **LRS 2** | 95% | 82% | 94% | 86% | 82% | 95% | 94% | 84% | 90% | 91% |
| **LRS 3** | 92% | 88% | 81% | 79% | 93% | 83% | 93% | 93% | 80% | 90% |
| **SPV3** | 52% | 43% | 49% | 47% | 59% | 64% | 66% | 65% | 68% | 69% |
| **JM Shafer** | 32% | 24% | 4% | 12% | 19% | 16% | 12% | 9% | 9% | 11% |
| **Rifle** | 0% | 0% | 3% | 0% | 0% | 0% | 0% | 0% | 0% | 0% |
| **Limon** | 1% | 1% | 13% | 1% | 2% | 0% | 0% | 0% | 0% | 0% |
| **Knutson** | 3% | 2% | 15% | 1% | 2% | 0% | 0% | 0% | 0% | 0% |
| **Pyramid** | 1% | 4% | 1% | 1% | 10% | 10% | 10% | 10% | 5% | 4% |
| **Burlington** | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% |

*Projected Availability Factors 2021 to 2030 for Thermal Resources*

For modeling purposes, availability factors are a result of modeled forced outage factors as well as planned outage hours. Tri-State assumes a 4% forced outage factor for all coal-fired generation. Historically, gas and oil resources are not assigned a forced outage factor due to their limited annual capacity factors. Tri-State is currently updating its models to reflect recommended forced outage factors as provided by Black & Veatch (Appendix A).

[12] Representative of monthly billing demands per the contracts. Actual maximum available hourly capacity in any given month varies.

**Applicable Scheduled Outage Plan over the RAP:**

| | Craig 1 | Craig 2 | Craig 3 | LRS 2 | LRS 3 | SPV3 |
|---|---|---|---|---|---|---|
| **Start Date** | | | | | | |
| **Stop Date** | | | | | | |
| **Start Date** | | | | | | |
| **Stop Date** | | | | | | |
| **Start Date** | | | | | | |
| **Stop Date** | | | | | | |

## 3. Purchased Power Resources

The following list provides summary information regarding current firm purchase power agreements in regards to capacity, energy and demand side resources. Tri-State does not have any wheeling or coordination agreements that provide capacity and energy.

Contract Purchases and Renewable Power Purchase Agreements differ from thermal resources in regards to applicable characteristics and costs. The format used below is intended to present the applicable data for these agreements as required in Rule 3605(c).

Summer capacities are representative of contract demand available to serve July peak.

### Contract Purchases:

Basin CROD Western Interconnection BEPC: Colorado & Wyoming: 268 MW summer capacity, ~1580 GWh/year[13]. Effective Date 1/16/1975; Renewed Date 10/1/2017; Contract Expires 12/31/2050.

- If either party wishes to terminate this agreement on its expiration date of 12/31/2050, notice must be given to the other party by January 1, 2045 in writing. Otherwise, this contract will remain in effect beyond its expiration date of 12/31/2050 until such time that either party gives to the other party not less than five years written notice of intent to terminate.

Basin Electrically East BEPC: All Requirements Purchase Contract for Electrically East Loads[14], Effective Date 1/16/1975; Renewed Date 10/1/2017; Contract Expires 12/31/2050.

- If either party wishes to terminate this agreement on its expiration date of 12/31/2050, notice must be given to the other party by January 1, 2045 in writing. Otherwise, this contract will remain in effect beyond its expiration date of 12/31/2050 until such time that either party gives to the other party not less than five years written notice of intent to terminate.

CRSP WAPA: 231 MW summer capacity ~1424 GWh/year. Seasonal Contract Rate of Delivery, specified monthly capacity and energy, and multiple delivery points apply to this contract. Effective Date 10/1/1989; Renewed Date 10/1/2017; Contract Expires 9/30/2057.

[13] Profile detail is shown in Projected Annual Emissions, Capacity Factors and Availability section
[14] Profile detail is shown in Projected Annual Emissions, Capacity Factors and Availability section

- Contracts TS-89-0005 and PL-89-0002 expire end of day, 9/30/2024. Contract TS-17-0128 is currently effective and commences delivery of Firm Electric Service beginning of day, 10/1/2024 through end of day 9/30/2057.

LAP WAPA: 353 MW summer capacity, ~900 GWh/year. Seasonal Contract Rate of Delivery, specified monthly capacity and energy, and multiple delivery points apply to this contract, Effective Date 10/1/1989; Contract Expiration 9/30/2054.

- Contract TS-89-0002 expires end of day, 9/30/2024. Contract TS-14-0238 is currently effective and commences delivery of Firm Electric Service beginning of day, 10/01/2024 through end of day, 9/30/2054.
- LAP contract includes rights to Mt. Elbert pump back storage 176 MW summer capacity with a 70% efficiency and prescribed generating and pumping hours. The Mt. Elbert contract capacity shares transmission with the LAP contract and the combination of usage cannot exceed the LAP contract max capacity in any hour.

Native American WAPA Allocations: Monthly (fixed schedule peaking) at 5 MW annually, ~28 GWh/year. Effective Date 10/1/2004; Expires 10/1/2024.

Central Valley Electric: ~1 MW capacity, ~5 GWh/year. Effective Date 12/05/1996; Contract Expires Evergreen

Additionally, Tri-State has several contracts under WSPP agreements that serve Utility Member system load associated with wind and solar facility station service for generators that are under contract and deliver energy to third party utilities but are located in a Tri-State Utility Member's service territory. These contracts are de minimis in nature (i.e., under 1 GWh in annual energy; 2 MW maximum demand).

### Energy and Capacity Payments for Contract Purchases

The following rates are averaged over the RAP:

| **Resource** | **Energy Rate** *($/MWh)* | **Demand Rate** *($/KW-month)* |
|---|---|---|
| Basin CROD Western Interconnection | [redacted] | [redacted] |
| Basin Electrically East | | |
| CRSP | $12.19 | $5.18 |
| LAP | $15.72 | $4.12 |
| Native American WAPA Allocations | [redacted] | N/A |
| Central Valley Electric | | N/A |

### Renewable Power Purchase Agreements:

Cimarron (First Solar) Purchase: Facility located in northeastern New Mexico, 30 MW (Maximum Capacity), ~64 GWh/year. Effective Date 2/23/2009; COD 11/25/2010; Contract Expires 11/24/2035.

[15] Composite rate encompassing energy and demand components
[16] Composite rate encompassing energy and demand components

Kit Carson Wind Purchase: Facility located in eastern Colorado, 51 MW (Maximum Capacity), ~185 GWh/year. Effective Date 6/30/2009; COD 11/19/2010; Contract Expires 11/30/2030.

Colorado Highlands Wind Purchase: Facility located in northeastern Colorado, 94 MW (Maximum Capacity) 91 MW (Nameplate Capacity), ~369 GWh/year. Effective Date 2/28/2012; COD 12/6/2012; Contract Expires 12/31/2032.

Carousel Wind Purchase: Facility located in eastern Colorado, 150 MW (Maximum Capacity), ~665 GWh/year. Effective Date 12/27/2013; COD 07/07/2016; Contract Expires 7/31/2041.

San Isabel Solar Purchase: Facility located in southern Colorado, 30 MW (Maximum Capacity), ~77 GWh/year. Effective Date 8/19/2015; COD 12/5/2016; Contract Expires 12/31/2041.

Alta Luna Solar Purchase: Facility located in southern New Mexico, 25 MW (Maximum Capacity), ~77 GWh/year. Effective Date 9/24/2015; COD 1/12/2017; Contract Expires 01/31/2042.

Twin Buttes II Wind Purchase: Facility located in southeastern Colorado, 75 MW (Maximum Capacity), ~302 GWh/year. Effective Date 6/1/2015; COD 12/28/2017, Contract Expires 12/31/2042.

Spanish Peaks Solar Purchase: Facility located in southern Colorado, 100 MW (Maximum Capacity), ~267 GWh/year. Effective Date 12/12/2018; Expected COD 11/01/2023, Contract Expires 11/30/2038*.

Crossing Trails Wind Purchase: Facility located in eastern Colorado, 104 MW (Maximum Capacity), ~439 GWh/year. Effective Date 2/5/2019; Expected COD 12/18/2020, Contract Expires 12/31/2035*.

Niyol Wind Purchase: Facility located in northeastern Colorado, 200 MW (Maximum Capacity), ~843 GWh/Year. Effective Date 12/18/2019; Expected COD 12/31/2021, Contract Expires 12/31/2041*.

Escalante Solar Purchase: Facility located in western New Mexico, 200 MW (Maximum Capacity), ~566 GWh/Year. Effective Date 12/10/2019; Expected COD 11/30/2023, Contract Expires 11/30/2040*.

Axial Basin Solar Purchase: Facility located in northwestern Colorado, 145 MW (Maximum Capacity), ~370 GWh/Year. Effective Date 12/10/2019; Expected COD 12/31/2023, Contract Expires 12/31/2038*.

Dolores Canyon Solar Purchase: Facility located in southwestern Colorado, 110 MW (Maximum Capacity), ~297 GWh/Year. Effective Date 12/10/2019; Expected COD 12/31/2023, Contract Expires 12/31/2038*.

Spanish Peaks II Solar Purchase: Facility located in southern Colorado, 40 MW (Maximum Capacity), ~107 GWh/Year. Effective Date 12/10/2019; Expected COD 12/31/2023, Contract Expires 12/31/2038*.

Coyote Gulch Solar Purchase: Facility located in southwestern Colorado, 120 MW (Maximum Capacity), ~331 GWh/Year. Effective Date 1/13/2020; Expected COD 12/31/2023, Contract Expires 12/31/2038*.

All solar power purchase agreements are assumed to have declining annual energy at approximately 0.5% per year to reflect solar panel degradation

*Contract expiration calculated from expected COD

**Small Power Producers (Hydropower) contracts are as follows:**

| Facility Name (Maximum Capacity) | Effective Date | Expiration | Location |
|---|---|---|---|
| Boulder Hydro (5MW) & Other Facilities (1.27 MW) | 6/1/2018 | 5/31/2028 | Colorado |
| Denver Water/Williams Fork (3.5 MW) | 1/1/2007 | 12/31/2026 | Colorado |
| Mancos/Jackson Gulch (0.26 MW) | 9/1/1995 | 2/8/2035 | Colorado |
| Vallecito/Ptarmigan (5.6 MW) | 6/25/2004 | 6/24/2024 | Colorado |
| Garland Canal (2.9 MW) | 12/10/2014 | 12/31/2024 | Wyoming |
| Tri-County Water/Ridgway (8 MW) | 8/22/2012 | 9/30/2023 | Colorado |

## Energy Payments for Renewable Power Purchase Agreements

The following rates are averaged over the RAP. Capacity rates are not applicable to our Renewable Power Purchase Agreements:

| Resource | Energy Rate *($/MWh)* |
|---|---|
| Cimarron | [redacted] |
| Kit Carson | |
| Colorado Highlands | |
| Carousel | |
| San Isabel | |
| Alta Luna | |
| Twin Buttes II | |
| Spanish Peaks | |
| Crossing Trails | |
| Niyol | |
| Escalante | |
| Axial | |
| Dolores Canyon | |
| Spanish Peaks II | |
| Coyote Gulch | |
| Boulder Hydro & Other Facilities | |
| Denver Water/Williams Fork | |
| Mancos/Jackson Gulch | |
| Vallecito/Ptarmigan | |
| Garland Canal | |
| Tri-County Hydropower | |

## Contract Provisions – Modification of Capacity and Energy Purchased

The above contract purchases and renewable purchase power agreements are a combination of must take energy or take or pay energy. Limited ability to modify capacity or energy purchased under these contracts exists. The few exceptions are listed below:

- Annually LAP contract capacity and energy is adjusted by WAPA per the contract formula. Additionally, WAPA can adjust capacity and energy due to changes in hydrology and river operations or the addition of new resources.
- At predetermined dates in the CRSP contract, WAPA will adjust capacity and energy as necessary up to the maximum 1% withdrawal limit for the resource pool. Additionally, WAPA can adjust capacity and energy due to changes in hydrology and river operations or the addition of new resources.
- All utility scale renewable projects have a right of first refusal option with regard to facility expansion and exercise of such option when made available could result in additional capacity and energy.
- All utility scale renewable projects allow for Tri-State to take excess energy produced over and above expected contract energy as defined by each contract
- The majority of Tri-State's utility scale renewable contracts have a provision to modify energy without penalty under certain conditions through an allowable curtailment option. The allowable curtailment amount varies by contract but does not exceed 1% of annual contract energy.

Note:

- The Basin CROD Western Interconnection contract does not expressly allow for the modification of capacity or energy amounts purchased. The contract exhibit identifies a set hourly energy profile that supplier will deliver and Tri-State will receive.
- The Basin Electrically East contract does not expressly allow for the modification of capacity or energy amounts purchased. The Basin Electrically East contract is a full requirements contract, and supplier is obligated to serve Tri-State Utility Member System load located in the Eastern Interconnection in its entirety at delivery points as identified in the contract including changes to Utility Member System load as a result of natural cycles of load growth or decline.

### Emissions Associated with Contract Purchases and Renewable Purchase Power Agreements

Tri-State receives Renewable Energy Credits (RECs) associated with its Renewable Purchase Power Agreements.

The WAPA LAP contract energy is generally sourced from power generated at federal dams in the Pick-Sloan Missouri Basin Program – Western Division and the Frying pan-Arkansas Project, collectively Loveland Area Projects. The WAPA CRSP Contract energy is generally sourced from power generated by the Salt Lake Area Integrated Projects. WAPA purchases energy from other sources as needed to meet the marketing plan obligations of its federal electric service customers including the LAP and CRSP contracts with Tri-State. Primarily these deliveries are from hydro. Annually, Tri-State receives RECs for prior year deliveries, which are recorded in WREGIS.

Historical emissions for Basin CROD Western Interconnection and Basin Electrically East contracts are estimated below:

*Estimated Historical Emission Rates*

| ***lbs. per MWH*** | **$CO_2$** | **$SO_2$** | **NOx** | **PM** | **Hg** |
|---|---|---|---|---|---|
| **Basin CROD Western Interconnection** | 2305 | 1.462 | 2.3705 | .13615 | .00004395 |
| **Basin Electrically East** | 1239.8 | 1.4 | 1.0 | UA | UA |

**UA= Unavailable[17]**

The Basin CROD Western Interconnection contract and the Basin Electrically East contract do not specify a source within the contract. Basin has the sole ability to determine the source of the energy for these contracts on a daily and hourly basis. Both contracts do require the energy to be delivered to specific delivery points. Based on this, the energy provided by these contracts are "unspecified energy" as identified in the Colorado AQCC Regulation 22. In order to estimate emissions of these contracts for the purpose of this information filing, Tri-State considered the following:

Basin CROD Western Interconnection Contract: Historically this contract has been primarily served by LRS generation so an average of LRS 2 and LRS 3 emissions factors was used. Future supply of this contract is in no way limited to a source of LRS. Organized market development, changing environmental landscape in the Western Interconnection, changing market or business conditions for BEPC or other factors can potentially influence BEPC's choice for hourly sourcing of this contract energy.

Basin Electrically East: This load in its entirety is within the Southwest Power Pool (SPP) footprint and BEPC supplies this load through the SPP market process. Given this, the egrid[18] sub region of MRO West was used as a proxy to represent emissions for this contract. The total output emission rates were used for $CO_2$, NOx and $SO_2$.

Additionally, we note that Tri-State receives RECs related to both of the Basin contracts as a member of BEPC under an associated board policy.

While the above emissions for Tri-State's Basin contracts are estimates based on historical sourcing only, Tri-State will explore further the projected emissions sources for each of these contracts within the bounds of the Colorado AQCC regulations, both currently effective and under development, during its ERP process leading to the December 1 filing to accurately reflect the emissions of these contracts and their impact on carbon reduction in future years.

## Utility Member System Distributed Generation

Tri-State's wholesale power contract with each of its Utility Member systems and applicable Tri-State Board policies allow for and facilitate the development of local distributed generation projects in Tri-State Utility Members' service territories, including community solar projects. These renewable and distributed projects help to fulfill both Colorado and New Mexico RES/RPS requirements, as well as satisfy Utility Members' and consumers' interest in purchasing renewable power from locally-sited projects.

As of May 2020, 66 renewable or distribution generation projects, totaling 136 MW of capacity and capable of producing ~380 GWh/year are operating or under development. Approximately 85% of

[17] Data for this sub region was not available for particulate matter or mercury emissions.
[18] Environmental Protection Agency - egrid 2018 Summary Tables

Utility Member system distributed generation is located in Colorado, and on a capacity basis, approximately 75% of the distributed generation in Colorado and New Mexico is solar. It is expected that the number of these projects will continue to grow as pricing for renewable resources continues to be attractive and Utility Members continue to show interest in supporting local renewable projects. These numbers are also expected to grow as a result of Tri-State's Board of Directors approving a new policy in 2019 that will facilitate the development of community solar projects throughout its Utility Members' service territories.

These resources are not owned by, or contracted to, Tri-State, but instead serve Utility Member system load directly, so Tri-State has not attempted to provide a detailed assessment of these generation projects.

## 4. Demand Side Management & Energy Efficiency

As reported in Tri-State's 2019 Annual Progress Report an ongoing part of Tri-State's Action Plan is the implementation of Demand Side Management (DSM) and Energy Efficiency (EE) programs. Options that have been evaluated include programs related to residential, small commercial, irrigation, large commercial and industrial programs. These offerings are continually refined based on effectiveness and member feedback. As a reminder, Tri-State does not have retail load and is reliant upon Utility Member system participation in DSM and EE program implementations.

Current offerings for Demand Side Management include:

- Demand Response (DR) related to air conditioning, water heating and irrigation
    - Four Utility Member systems currently have irrigation DR programs
- Energy shaping related to electric thermal storage and electric vehicle charging station
    - Eleven Utility Member systems use time of use rates for storage heater control
    - Several Utility Member systems are investigating or have implemented residential demand rates in an attempt to control/shift load during peak times

Tri-State's current A-40 rate structure provides Tri-State's Utility Member systems an incentive to control load during Tri-State's defined peak period. Tri-State's A-40 rate consists of energy, generation demand and transmission demand rates. Many utility Member systems successfully use active load control methods during Tri-State's defined peak period to reduce their monthly demand usage and related demand charges.

Current offerings for Energy Efficiency include:

- Heat Pump Projects working with the Electric Power Research Institute (EPRI) and our Utility Member systems
- Rebates on education programs for training in Energy Auditing
- Irrigation program to educate Utility Member systems in regards to efficiency
- Incentives are offered in many areas such as residential and commercial lighting, appliances, air conditioning, motors, air and ground source heat pumps and assisting in energy efficient education and training

**Year End 2018[19] Cumulative Energy Efficiency Results:**

| Category | Typical Measures | kW Savings | kWh Savings |
|---|---|---|---|
| Agriculutural | Irrigation Motors<br>Variable Speed Drive Retrofits | 13,080 | 21,902,726 |
| C&I HVAC | Air Source and Ground Source Heat Pumps | 7,275 | 9,263,112 |
| C&I Lighting | LED Lighting<br>Street & Parking Lot Lighting<br>Refrigerated Case Doors | 25,434 | 91,528,578 |
| C&I Motors | Variable Speed Drive Retrofits | 3,968 | 8,199,393 |
| Residential HVAC | Air Conditioners<br>Air Source and Ground Source Heat Pumps | 83,891 | 57,344,907 |
| Residential - Othe | LED Lamps, Energy Star Appliances<br>Electric Water Heaters<br>Low Income Weatherization | 51,488 | 23,905,259 |
| **Total** | | **185,136** | **212,143,975** |

**Energy Efficiency Rebate History**

- 2014 - $2,131,637
- 2015 - $2,128,582

[19] Table identifier corrected to 2018 from 2019 as shown in June 1 filing.

- 2016 - $2,078,582
- 2017 - $2,349,835
- 2018 - $3,338,435
- 2019 - $3,327,027
- 2020 Budget - $6,697,353

Additionally, in late 2019, Tri-State initiated a Demand Side Management (DSM) and Energy Efficiency (EE) Potential study with an outside consultant with the goal of receiving updated information in regards to achievable potential and cost savings in these areas for use in Tri-State's 2020 ERP process. Tri-State intends to leverage this study along with Utility Member systems input to evolve and expand its DSM and EE products and services in a manner that is beneficial to Tri-State and Utility Member systems. Key findings from this study include:

- Identifies significant cost effective opportunities for energy and demand savings for energy efficiency programs
- Identifies limited opportunities for DR programs but long term operation is key for cost effectiveness
- Distributed Energy Resource (DER) programs are not cost effective except for larger systems in specific regions

The complete study is included as Appendix C to this report.

## 5. Benchmarking

For the purposes of the Rule 3605(c)(II) Benchmarking requirement, Tri-State engaged Black and Veatch to perform an analysis of cost and performance of existing owned and contracted resources as compared to generic resources. The scope of this benchmarking analysis was limited to the following:

- Thermal and renewable utility scale resources that are:
    - Commercially operational, and
    - Located in the state of Colorado, or
    - Located outside of the state of Colorado but capable of serving Colorado load at any time.
- Basin Western Interconnection and Basin Electrically East contracts

Alta Luna and Cimarron renewable resources located in New Mexico are included in the benchmarking process but have never been scheduled to Colorado load.

Resources excluded from the benchmarking process include:

- Federal hydro contracts of LAP and CRSP as these long-term, cost-based contracts for delivery of firm, renewable, quasi-dispatchable power contracts with certain transmission and ancillary service benefits do not have a reasonable comparison within the generic resource pool.

- Other small contract purchases, small hydro power producer contracts

The full methodology, results and insights from the Black & Veatch Benchmarking process are located in Appendix B: Black & Veatch Report on Benchmarking of Existing Resources

## 6. Ancillary Service Assessment

Tri-State meets its ancillary service requirements through Network Integration Transmission Service Agreements and Balancing Authority Ancillary Service Agreements. In the Western Interconnection, Tri-State receives ancillary services from PacifiCorp, PSCo, Public Service of New Mexico and WAPA. As mentioned previously in this report, Tri-State's electrically east load is served via a full requirements contract with BEPC, which includes ancillary services.

The following is a list of the primary ancillary services required via applicable Open Access Transmission Tariffs and how Tri-State acquires these services including any applicability to Tri-State resources:

Scheduling, System Control & Dispatch: Tri-State pays for this service monthly from appropriate Transmission Providers or Balancing Authorities. Tri-State Resources do not have any impact on or relation to this service.

Reactive Supply & Voltage Control: Tri-State pays for this service monthly from appropriate Transmission Providers or Balancing Authorities. Tri-State's generating resources do not have any impact on or relation to this service. Tri-State does, however, have several applicable agreements with entities to partially self-supply reactive support via transmission system equipment in exchange for a reduced cost in service. Separately, Tri-State generation resources are required via NERC Reliability Standards to follow reactive power instructions from Transmission Operators and operate in automatic voltage control mode.

Regulation and Frequency Response (includes load following capabilities): Tri-State pays for this service monthly from appropriate Transmission Providers or Balancing Authorities. Applicable Tri-State-owned or contracted resources and Utility Member system distributed resources nameplate capacity are, at times, a factor in determining regulation cost, but Tri-State does not have any obligation to regulate for its own load or resources. Tri-State does, however, have generating resources that have the capability to operate in Automatic Generation Control (AGC) mode and thereby provide regulation as a service for a cost.

Tri-State generating resources that are AGC capable include:

- Craig 1, 2, and 3
- LRS 2
- Springerville 3
- JM Shafer
- Knutson 1,2
- Limon 1,2
- Pyramid 1,2,3,4
- Burlington 1,2

Energy Imbalance Service: Tri-State currently pays for this service monthly from appropriate Transmission Providers or Balancing Authorities. Beginning in 2021, a portion of Tri-State's load and resources will be in two energy imbalance markets – the Western Energy Imbalance Service (WEIS) and the Western Energy Imbalance Market (WEIM). Upon entry, Tri-State will be able to participate with its resources located within the respective market's footprint. Financial settlements will occur with the appropriate Market Operator.

Operating Reserve Spinning Service: Tri-State self-provides spinning reserves through Southwest Reserve Sharing Group membership and via two sub-entity Reserve Sharing Group Agreements. Tri-State generating resources typically online and capable of carrying spinning reserves include:

- Craig 1
- Craig 2
- Craig 3
- LRS2
- LRS3
- Springerville 3
- JM Shafer

Due to recent changes in operating standards in the Western Interconnection, operating reserves may be fully served via non-spinning supplemental service rather than the previous requirement that operating reserves must include of a minimum of 50% spinning reserves.

Operating Reserve Supplemental Service:

Tri-State self-supplies spinning reserves through Southwest Reserve Sharing Group member and via two sub-entity Reserve Sharing Group Agreements. Tri-State generating resources with quick start capability to qualify for supplemental service include:

- Burlington 1,2
- Limon 1,2
- Pyramid 1,2,3,4

Generator Imbalance Service: Tri-State currently takes and pays for this service monthly from appropriate Transmission Providers or Balancing Authorities. Beginning in 2021, a portion of Tri-State's load and resources will be in two energy imbalance markets – the WEIS and the WEIM. Upon entry, Tri-State will be able to participate with its resources located within each respective market's footprint. Financial settlements will occur with the appropriate Market Operator.

Flex Reserve Service: Tri-State currently takes and pays for this service monthly from appropriate Transmission Providers or Balancing Authorities. This service is calculated based on proportional wind capacity contribution within the footprint as is used by the Balancing Authority to cover the costs of ramping requirements related to wind intermittency.

Loss Supply Service: Tri-State either pays for this service monthly from appropriate Transmission Providers or Balancing Authorities or provides physical loss requirement depending on specific contractual arrangements.

## Confidential Information

Pursuant to Commission Rule 3605(a)(IV)(K), the following is a list of information included in this Assessment of Existing Resources and which Tri-State has designated as confidential information:

- Scheduled Outage Plan (Maintenance

## Highly Confidential Information

Pursuant to Commission Rule 3605(a)(IV)(K), the following is a list of information included in this Assessment of Existing Resources and which Tri-State has designated as highly confidential information:

- Fixed O&M Expenses
- Variable O&M Expenses
- Fuel Price Forward Curves (Gas and Coal)
- Contract/PPA Energy Rate, except in regards to Tri-State's LAP and CRSP hydro power purchase contracts with WAPA.
- Contract/PPA Capacity Rate, except in regards to Tri-State's LAP and CRSP hydro power purchase contracts with WAPA.
- Performance or Operating Output guarantees and any associated pricing adjustments included in Tri-State' Renewable Power Purchase Agreements
- Any information protected by a confidentiality clause in a PPA

# Appendix A: Black & Veatch Report on Review of Existing Resources

BLACK & VEATCH

August 3, 2020 Revision

# Report on Review of Existing Resources

## Executive Summary

As part of the energy resource planning process, Tri-State Generation & Transmission Association ("Tri-State") must establish assumptions concerning the future performance and cost of its existing resources for the purposes of modeling the long-term performance and cost of the resource plan ("Modeled Values"). Tri-State retained Black & Veatch ("we" or "us") to review the Modeled Values and as necessary recommend changes to the Modeled Values to better represent future resource performance and cost (the "Review"). The Modeled Values included capacity, heat rate, availability rate, forced outage rate, emissions, renewable production profiles, variable O&M costs and fixed O&M costs. The existing resources included eighteen (18) coal, gas and oil fired resources) two (2) long-term purchase agreements with Basin Electric and seven (7) renewable (solar and wind) facilities located across the Tri-State system. This Report summarizes the scope, methodology and results of our Review.

Our approach was to compare the Modeled Values against actual performance and cost data provided to us by Tri-State, data collected by federal regulatory agencies and national reliability coordinators, and data reported by other generators for resources of similar technology, size, age and location. In cases where a Modeled Value was significantly different from the values shown in the data sources, and if the data was determined to be of reasonable quality, we then recommended an alternative modeled value for consideration by Tri-State (each a "Recommended Modeled Value").

Our review revealed that some of the Modeled Values were significantly different than those shown in one or more of the data sources. Differences included heat rates for the Burlington resources, fixed O&M costs for the Rifle resource, and NOx emission rates for the Burlington and Rifle resources. They also included SO2 emission rates for the Rifle and Shafer resources, availability factors for the Burlington, Limon, Rifle and Shafer resources, and forced outage factors for the Burlington, Knutson, Limon, Rifle and Shafer plants. For each of these we provided a Recommended Modeled Value for consideration by Tri-State. The Recommended Modeled Values are summarized in the Results section of this Report.

## Scope

The scope of our Review was defined by Tri-State and included the resources shown in Table 1 below.

Six (6) of the Existing Resources are coal fired. These include the Craig coal-fired Units 1 through 3 located in western Colorado ("wco"), the Laramie River coal-fired station ("LRS") Units 2 and 3 located in Wyoming ("wyo"), and Springerville coal-fired Unit 3 located in Arizona ("arz"). These resources are either partially owned or partially controlled by Tri-State with the exception of Craig Unit 3 which is wholly owned and Springerville Unit 3 which is wholly leased with 100 MW of the Total Capacity sold to a third party under a tolling agreement through the summer of 2036. The capacity currently controlled by Tri-State is shown as the "Tri-State Modeled Capacity".

Another ten (10) of the Existing Resources are oil or gas fired combustion turbines that are fully owned by Tri-State. These include the Burlington Units 1 and 2, the Knutson Units 1 and 2, the Limon Units 1 and 2 and the Pyramid Units 1 through 4. The Burlington, Knutson and Limon Units are located in eastern Colorado and the Pyramid Units are located in southern New Mexico. All of these resources are fully controlled by Tri-State.

Another two (2) of the Existing Resources are gas-fired combined cycle plants that are fully owned by Tri-State. These include the Rifle plant located in western Colorado and the Shafer plant located in eastern Colorado.

These coal, gas or oil fired resources are referred to collectively as the "thermal" resources.

Another seven (7) resources are solar or wind powered "renewable" resources with output purchased by Tri-State under power purchase agreements ("PPA"). Five (5) of these resources are located in eastern Colorado ("eco") and the remaining two (2) are located in New Mexico. All of the output from these resources is purchased by Tri-State.

The remaining two (2) Existing Resources are long-term contract purchases from Basin Electric Power Cooperative ("Basin"), collectively the "Basin Contracts". The first contract is known as the Western CROD Contract ("Basin West") and the other as the Basin Electrically East Contract ("Basin East"). No specific generating resource is associated with each Basin Contract. Basin has the sole discretion to choose how the Basin West contract is supplied on a day ahead and hour ahead basis. The Basin East contract is supplied via Southwest Power Pool (SPP). The Basin West contract has a set hourly energy profile by month for each year of the contract. The Basin East Contract is a full requirements contract and supply is based on actual energy needs of Tri-State's Utility Member Systems located in the Eastern Interconnection. Tri-State purchases all energy as contracted under the Basin Contracts.

*Table 1 – Summary of Resources to be Reviewed*

| | Plant/Unit | Technology | Type | Location | Nominal Capacity (MW) | Tri-State Modeled Capacity (MW) | Year In Service |
|---|---|---|---|---|---|---|---|
| 1 | GC-Craig 1-NW_CO | Steam Turbine - Coal | Owned | wco | 427 | 102 | 1980 |
| 2 | GC-Craig 2-NW_CO | Steam Turbine - Coal | Owned | wco | 410 | 98 | 1979 |
| 3 | GC-Craig 3-NW_CO | Steam Turbine - Coal | Owned | wco | 448 | 448 | 1984 |
| 4 | GC-LRS 2-WY | Steam Turbine - Coal | Owned | wyo | 570 | 231 | 1981 |
| 5 | GC-LRS 3-WY | Steam Turbine - Coal | Owned | wyo | 570 | 230 | 1982 |
| 6 | GC-SV 3-SPV | Steam Turbine - Coal | Owned | arz | 417 | 317 | 2006 |
| 7 | GG-Burlington 1-E_CO | Frame CT - Oil | Owned | eco | 55 | 55 | 1977 |

| | Plant/Unit | Technology | Type | Location | Nominal Capacity (MW) | Tri-State Modeled Capacity (MW) | Year In Service |
|---|---|---|---|---|---|---|---|
| 8 | GG-Burlington 2-E_CO | Frame CT - Oil | Owned | eco | 55 | 55 | 1977 |
| 9 | GG-Knutson 1-E_CO | Frame CT - Gas | Owned | eco | 70 | 70 | 2002 |
| 10 | GG-Knutson 2-E_CO | Frame CT - Gas | Owned | eco | 70 | 70 | 2002 |
| 11 | GG-Limon 1-E_CO | Frame CT - Gas | Owned | eco | 70 | 70 | 2003 |
| 12 | GG-Limon 2-E_CO | Frame CT - Gas | Owned | eco | 70 | 70 | 2003 |
| 13 | GG-Pyramid 1-S_NM | Aeroderivative CT - Gas | Owned | snm | 40 | 40 | 2003 |
| 14 | GG-Pyramid 2-S_NM | Aeroderivative CT - Gas | Owned | snm | 40 | 40 | 2003 |
| 15 | GG-Pyramid 3-S_NM | Aeroderivative CT - Gas | Owned | snm | 40 | 40 | 2003 |
| 16 | GG-Pyramid 4-S_NM | Aeroderivative CT - Gas | Owned | snm | 40 | 40 | 2003 |
| 17 | GG-Rifle-NW_CO | Combined Cycle - Gas | Owned | wco | 81 | 81 | 1987 |
| 18 | GG-Shafer-E_CO | Combined Cycle - Gas | Owned | eco | 272 | 272 | 1994 |
| 19 | CP-AltaLuna-S_NM | Tracking Array Solar | PPA | nm | 25 | 25 | 2017 |
| 20 | CP-SanIsabel-E_CO | Tracking Array Solar | PPA | eco | 30 | 30 | 2016 |
| 21 | CP-FirstSolar-N_NM | Fixed Solar | PPA | nm | 30 | 30 | 2010 |
| 22 | CP-ColoHighlands-E_CO | Wind | PPA | eco | 91 | 91 | 2012 |
| 23 | CP-KitCarson-E_CO | Wind | PPA | eco | 51 | 51 | 2010 |
| 24 | CP-TwinButtes-E_CO | Wind | PPA | eco | 76 | 76 | 2017 |
| 25 | CP-Carousel-E_CO | Wind | PPA | eco | 150 | 150 | 2015 |
| 26 | CP-Basin_West | Basin System | PPA | eco | 268 | 268 | 2017 |
| 27 | CP-Basin_East | Basin System | PPA | eco | 317 | 317[1] | 2017 |

The scope of parameters to review for each of these resources was also specified by Tri-State. The parameters included heat rate, variable O&M cost, fixed O&M cost, CO2 emission rate, NOx emission rate, SO2 emission rate, availability rate, forced outage rate, and capacity factor for the renewable resources only (each a "Parameter").

## Methodology

Our methodology for the Review was to compare the Modeled Values against historical Parameters from three (3) data sources and base our Recommended Modeled Values on the results of that comparison. The Modeled Values were provided to us by Tri-State and consisted of Parameters for each of the existing resources. The first data source was historical data provided to us by Tri-State for heat rate, availability rate and forced outage rate for the thermal resources ("Tri-State Data"). The second data source was historical data gathered from federal regulators by the S&P Global Market Intelligence

[1] Basin East is a full requirements contract so capacity is not specified in the contract but rather fluctuates with the demand forecast of the members.

service ("S&P")[2] for heat rate, variable O&M cost, fixed O&M cost, CO2 emission rate, NOx emission rate and SO2 emission rate for the thermal resources and capacity factor for the renewable resources ("S&P Data"). The third data source was a compilation of Parameters from S&P and from historical data reported by the North American Reliability Corporation ("NERC") for resources of similar technology, size, age and location to the Tri-State resources but that are owned or controlled by others ("Peer Group Data"). Comparing the Modeled Values against data from these three sources allowed us to evaluate the extent to which the Modeled Values were consistent with the actual historical Parameters of the resource and other similar resources in the market.

A summary of the key features of the Peer Group Data is provided in the table below.

*Table 2- Summary of Key Features of the Peer Group Data*

| - | Plant/Unit | Peer Group | NERC Regions | Capacity | COD | # of Units in GADS | GADS Data | # of Units in S&P | S&P Data |
|---|---|---|---|---|---|---|---|---|---|
| 1 | GC-Craig 1-NW_CO | Large Coal ST | MRO, WECC and SPP | 300 to 500 MW | 1980 to 2010 | 26 | 2015-2018 Forced Outage Factor (FOF) and Availability Factor (AF) | 41 | 2015-2018 Heat Rate, Non-Fuel O&M Variable Costs ($/MWh), Fixed O&M Costs ($/kw-mo), CO2 Emissions (lb/MMBtu), NOx Emissions (lb/MMBtu), SO Emissions (lb/MMBtu) |
| 2 | GC-Craig 2-NW_CO | Large Coal ST | MRO, WECC and SPP | 300 to 500 MW | 1980 to 2010 | 26 | | 41 | |
| 3 | GC-Craig 3-NW_CO | Large Coal ST | MRO, WECC and SPP | 300 to 500 MW | 1980 to 2010 | 26 | | 41 | |
| 4 | GC-LRS 2-WY | Large Coal ST | MRO, WECC and SPP | 300 to 500 MW | 1980 to 2010 | 26 | | 41 | |
| 5 | GC-LRS 3-WY | Large Coal ST | MRO, WECC and SPP | 300 to 500 MW | 1980 to 2010 | 26 | | 41 | |
| 6 | GC-SV 3-SPV | Large Coal ST | MRO, WECC and SPP | 300 to 500 MW | 1980 to 2010 | 26 | | 41 | |
| 7 | GG-Burlington 1-E_CO | Frame CT | MRO, WECC and SPP | 60 MW to 80 MW | 1970 to 2010 | 125 | | 49 | |
| 8 | GG-Burlington 2-E_CO | Frame CT | MRO, WECC and SPP | 60 MW to 80 MW | 1970 to 2010 | 125 | | 49 | |
| 9 | GG-Knutson 1-E_CO | Frame CT | MRO, WECC and SPP | 60 MW to 80 MW | 1970 to 2010 | 125 | | 49 | |
| 10 | GG-Knutson 2-E_CO | Frame CT | MRO, WECC and SPP | 60 MW to 80 MW | 1970 to 2010 | 125 | | 49 | |
| 11 | GG-Limon 1-E_CO | Frame CT | MRO, WECC and SPP | 60 MW to 80 MW | 1970 to 2010 | 125 | | 49 | |
| 12 | GG-Limon 2-E_CO | Frame CT | MRO, WECC and SPP | 60 MW to 80 MW | 1970 to 2010 | 125 | | 49 | |
| 13 | GG-Pyramid 1-S_NM | Aeroderivative CT | MRO, WECC and SPP | 40 MW to 60 MW | 1998 to 2008 | 122 | | 95 | |

[2] https://www.spglobal.com/marketintelligence/en/solutions/market-intelligence-platform

| | Plant/Unit | Peer Group | NERC Regions | Capacity | COD | # of Units in GADS | GADS Data | # of Units in S&P | S&P Data |
|---|---|---|---|---|---|---|---|---|---|
| 14 | GG-Pyramid 2-S_NM | Aeroderivative CT | MRO, WECC and SPP | 40 MW to 60 MW | 1998 to 2008 | 122 | | 95 | |
| 15 | GG-Pyramid 3-S_NM | Aeroderivative CT | MRO, WECC and SPP | 40 MW to 60 MW | 1998 to 2008 | 122 | | 95 | |
| 16 | GG-Pyramid 4-S_NM | Aeroderivative CT | MRO, WECC and SPP | 40 MW to 60 MW | 1998 to 2008 | 122 | | 95 | |
| 17 | GG-Rifle-NW_CO | Small CC | All | 50 MW to 100 MW | 1980 to 1995 | 21 | | 88 | |
| 18 | GG-Shafer-E_CO | Large CC | MRO, WECC and SPP | 250 MW to 350 MW | 1985 to 2005 | 17 | | 14 | |
| 19 | CP-AltaLuna-S_NM | Small Solar CO NM WY | WECC | 20 to 100 MW | All | n/a | n/a | 12 | 2015-2018 Capacity Factor, Non-Fuel O&M Variable Costs ($/MWh), Fixed O&M Costs ($/kw-mo) |
| 20 | CP-SanIsabel-E_CO | Small Solar CO NM WY | WECC | 20 to 100 MW | All | n/a | n/a | 12 | |
| 21 | CP-FirstSolar-N_NM | Small Solar CO NM WY | WECC | 20 to 100 MW | All | n/a | n/a | 12 | |
| 22 | CP-ColoHighlands-E_CO | Small Wind CO NM WY | WECC | 20 to 100 MW | All | n/a | n/a | 26 | |
| 23 | CP-KitCarson-E_CO | Small Wind CO NM WY | WECC | 20 to 100 MW | All | n/a | n/a | 26 | |
| 24 | CP-TwinButtes-E_CO | Small Wind CO NM WY | WECC | 20 to 100 MW | All | n/a | n/a | 26 | |
| 25 | CP-Carousel-E_CO | Large Wind CO NM WY | WECC | 100 MW + | All | n/a | n/a | 25 | |
| 26 | CP-Basin_West | n/a | n/a | n/a | n/a | n/a | n/a | n/a | n/a |
| 27 | CP-Basin_East | n/a | n/a | n/a | n/a | n/a | n/a | n/a | n/a |

For each peer group, the NERC region, capacity range and age range were selected such that the existing resource(s) and a reasonable number of third party resources would fall into the group. The total capacity of the existing resource rather than just the Tri-State share was considered in developing each peer group.

Once the peer groups were established, the associated Tri-State Data, S&P Data and Peer Group Data was acquired. Modeled Values and data were limited for the solar and wind resources. Tri-State has

Modeled Values for only capacity factor and none of the other Parameters (variable O&M, fixed O&M, etc.) since the existing wind and solar resources are not owned by Tri-State. Also, NERC has only recently begun requiring owners of renewable energy resources to submit performance and reliability data and NERC has not yet made the data available. Therefore, capacity factor was the only Parameter considered in Review of the wind and solar resources.

Modeled Values and data were also limited for the Basin Contracts because they are not resource specific. Modeled Values for the Basin Contracts included only CO2, SO2 and NOx emission rates. These Modeled Values were calculated by Tri-State based on historical emission rates for Laramie River Station (LRS2, LRS 3) for Basin West and egrid subregion MRO-W emissions were used for the Basin East. This approach reflects the fact that historically some of the energy from Basin West has likely been generated from coal fired power plants on the Basin system and that Basin East is served by the Southwest Power Pool. Modeled Values for the other Parameters (variable O&M, fixed O&M, etc. ) were not available. No Parameters were available in the S&P Data and Peer Group Data because S&P and NERC do not record data for non-resource specific system sales. Therefore CO2, SO2 and NOx emission rates were the only Parameters considered in review of the Basin Contracts. It is also important to note that none of the Parameters reviewed in this report including emissions are specified in the Basin Contracts.

Data analysis began with comparison of each Modeled Value against a four year (2015 – 2018 inclusive) average of the associated Parameter from the Tri-State Data, the S&P Data and the Peer Group Data. Data for the years 2019 and 2020 was excluded because it was either unavailable or incomplete at the time the Review was performed (Spring 2020). Each Modeled Value was then also compared against an average of the three averages (the “Grand Average”). In cases where the Modeled Value was more than 10% greater or less than the Grand Average (5% for the availability factor and forced outage factor Grand Averages), the difference was considered significant and we further examined the data to determine the cause of the difference including whether or not the Grand Average was skewed high or low by the presence of high or low outliers in the underlying data or the underlying data was of poor quality for some other reason. If the Grand Average proved to be of reasonable quality, we then recommended an alternative modeled value for consideration by Tri-State (a "Recommended Modeled Value").

The threshold for significance was only 5% for the availability factor and forced outage factor Grand Averages because the data ranged from only 70% to 100% and therefore, we felt that using a 10% threshold would mask too many significant differences.

## Results

Results of the data analysis are summarized in the following tables. Each table summarizes the analysis for one of the Parameters including the relevant Modeled Value, the Tri-State Data value, the S&P Data value, the Peer Group Data value and the Grand Average for each of the existing resources. Grand Averages highlighted in yellow indicate the Grand Average is significantly (+\- 10% or +/- 5%) different than the Modeled Value. Recommended Values highlighted in green indicate Recommended Values different than the Modeled Value.

Heat rate results show that the Grand Average was significantly different than the Modeled Value for several of the resources. However, review of the Grand Average revealed that the underlying Tri-State data and Peer Group data was skewed in most of these cases. For these resources, no change was recommended. The exception are the Burlington combustion turbine Units 1 and 2. A Recommended Modeled Value was therefore provided based on the Grand Average. A heat rate comparison was not applicable to the renewable resources and the Basin Contracts.

Variable O&M cost results show that the Grand Average was significantly different than the Modeled Value for nearly all of the resources. However, review of these Grand Averages revealed that the underlying S&P Data was not actual data (but rather calculated) for the coal-fired units and was skewed by extreme outliers for the combustion turbine units and for the Shafer combined cycle plant. As a result, the Recommended Modeled Values were the same as the Modeled Values for all the resources (no change recommended). A variable O&M Cost comparison was not applicable to the renewable resources and the Basin Contracts.

Fixed O&M cost results show that the Grand Average was significantly different than the Modeled Values for nearly all of the resources. However, the underlying S&P data and Peer Group data was judged to be of poor quality and therefore no changes to the Modeled Values were recommended. The exception was for the Rifle combined cycle plant, where a lower Recommended Modeled Value was provided. The Recommended Modeled Value was also expressed in $000s for convenience since Tri-State models fixed O&M on a dollar basis instead of $/kw-yr. A fixed O&M cost comparison was not applicable to the renewable resources and the Basin Contracts.

CO2 emission rate results show only a few significant differences between the Grand Averages and the Modeled Values. Further investigation into these differences revealed that the S&P Data and Peer Group Data was not actual but rather calculated. As a result, our Recommended Modeled Values were the same as the Modeled Values for all the resources (no change recommended). A CO2 emission comparison was not applicable to the renewable resources. A comparison was not applicable to the Basin Contracts because of the lack of S&P Data and Peer Group Data. As a result, our Recommended Modeled Values were the same as the Modeled Values for the Basin Contracts (no change recommended).

NOx emission rate results show that the Grand Average is significantly different than the Modeled Values for nearly all resources. However, no changes were recommended in most cases due to poor S&P Data and Peer Group Data quality. For Craig 2, no change was recommended because the significant difference is due to NOx emission controls that have been added to the unit. This causes the rate to be much less than Craig 1 as well as the S&P Data and Peer Group Data. Changes were recommended for Burlington Units 1 and 2 and the Rifle combined cycle plant. The Modeled Values are relatively high for these resources. It is possible that the Modeled Values reflect actual emission rates which are relatively high due to use of fuel oil at Burlington or lack of modern emission controls at Rifle. If this is the case, then no change should be made to the Modeled Value. A NOx emission comparison was not applicable to the renewable resources. A comparison was not applicable to the Basin Contracts because of the lack of S&P Data and Peer Group Data. As a result, our Recommended Modeled Values were the same as the Modeled Values for the Basin Contracts (no change recommended).

SO2 emission rate results show that the Grand Average is significantly different than the Modeled Values for all the resources. However, no changes were recommended in most cases due to poor S&P Data quality. The exception is the Rifle and Shafer resources. The Modeled Values are relatively low for these resources and so a higher Recommended Modeled Value is provided. An SO2 emission comparison was not applicable to the renewable resources. A comparison was not applicable to the Basin Contracts because of the lack of S&P Data and Peer Group Data. As a result, our Recommended Modeled Values were the same as the Modeled Values for the Basin Contracts (no change recommended).

Availability factor results show significant differences between the Grand Averages and the Modeled Values for the majority of the resources. However, in some of these cases (Craig Unit 1, Craig Unit 3, Springerville Unit 3, Knutson Unit 2 and Limon Unit 2) no changes were recommended due to the Tri-State data being skewed by low values for the years 2016 or 2018. For the other resources, a Recommended Modeled Value was provided based primarily on the Tri-State Data. The Recommended Modeled Value was also expressed in maintenance outage hours (MOH) for convenience since Tri-State models maintenance outages on an hourly basis instead of a percentage basis. An availability factor comparison was not applicable to the renewable resources and the Basin Contracts.

Forced outage factor results show significant differences between the Grand Averages and the Modeled Values for the majority of the resources. However, in some of these cases (Craig Unit 2, LRS Unit 2) no change was recommended since the Grand Average if rounded would equal the Modeled Value and therefore the Modeled Value was judged to be in a reasonable range. In other cases (Craig Unit 3, Springerville Unit 3) no changes were recommended due to the Tri-State data being skewed by low values for the years 2016, 2017 or 2018. For the other resources, a Recommended Modeled Value was provided based primarily on the Tri-State Data. The Recommended Modeled Value was also expressed in forced outage hours (FOH) for convenience since Tri-State models forced outages on an hourly basis instead of a percentage basis. A forced outage factor comparison was not applicable to the renewable resources and the Basin Contracts.

Renewable capacity factor results show significant differences between the Grand Averages and the Modeled Values for the majority of the resources. However, in some of these cases (San Isabel, Twin Buttes and Carousel) no change was recommended since the Tri-State and S&P data were skewed low due to outlier low values in 2015, 2016 or 2017. In the other cases (Colorado Highlands and Kit Carson) no changes were recommended due to the Peer Group Data being relatively low. A capacity factor comparison was not applicable to the thermal resources and the Basin Contracts.

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*Table 3 – Results of Review – Heat Rate (Btu/kwh)*

| | Heat Rate (Btu/kwh) | | | | | | | |
|---|---|---|---|---|---|---|---|---|
| Resource | Current Modeled | Tri-State Data | S&P Data | Peer Group Data (S&P) | Avg. Tri-State, S&P, Peer Group Data | Recommendation | Notes | Recommended Modeled |
| 1 GC-Craig 1-NW_CO | 10,316 | 10,176 | 10,213 | 10,582 | 10,324 | No change | Within reasonable range | 10,316 |
| 2 GC-Craig 2-NW_CO | 10,219 | 10,075 | 10,117 | 10,582 | 10,258 | No change | Within reasonable range | 10,219 |
| 3 GC-Craig 3-NW_CO | 10,135 | 10,156 | 10,227 | 10,582 | 10,322 | No change | Within reasonable range | 10,135 |
| 4 GC-LRS 2-WY | 9,926 | 10,035 | 10,099 | 10,582 | 10,239 | No change | Within reasonable range | 9,926 |
| 5 GC-LRS 3-WY | 10,286 | 9,917 | 10,117 | 10,582 | 10,206 | No change | Within reasonable range | 10,286 |
| 6 GC-SV 3-SPV | 9,945 | 13,205 | 10,183 | 10,582 | 11,323 | No change | Tri-State data skewed by high 2015 and 2018 values | 9,945 |
| 7 GG-Burlington 1-E_CO | 11,924 | 14,358 | 12,999 | 15,337 | 14,231 | 14,000 | Tri-State data not skewed, use average. | 14,000 |
| 8 GG-Burlington 2-E_CO | 11,924 | 13,610 | 12,999 | 15,337 | 13,982 | 14,000 | Tri-State data not skewed, use average. | 14,000 |
| 9 GG-Knutson 1-E_CO | 11,646 | 16,295 | 12,270 | 15,337 | 14,634 | No change | Tri-State and Peer Group data skewed | 11,646 |
| 10 GG-Knutson 2-E_CO | 11,646 | 15,553 | 12,515 | 15,337 | 14,469 | No change | Tri-State and Peer Group data skewed | 11,646 |
| 11 GG-Limon 1-E_CO | 11,646 | 10,984 | 12,106 | 15,337 | 12,809 | No change | Peer group data skewed | 11,646 |
| 12 GG-Limon 2-E_CO | 11,646 | 11,655 | 12,504 | 15,337 | 13,165 | No change | Peer group data skewed | 11,646 |
| 13 GG-Pyramid 1-S_NM | 9,742 | 9,688 | 9,908 | 10,898 | 10,164 | No change | Within reasonable range | 9,742 |
| 14 GG-Pyramid 2-S_NM | 9,742 | 9,699 | 10,026 | 10,898 | 10,207 | No change | Within reasonable range | 9,742 |
| 15 GG-Pyramid 3-S_NM | 9,742 | 10,069 | 10,394 | 10,898 | 10,453 | No change | Within reasonable range | 9,742 |
| 16 GG-Pyramid 4-S_NM | 9,742 | 9,972 | 10,230 | 10,898 | 10,366 | No change | Within reasonable range | 9,742 |
| 17 GG-Rifle-NW_CO | 10,658 | 6,925 | 7,672 | 7,934 | 7,510 | No change | Low Tri-State data from 2015 only, actuals higher due to duct burners. | 10,658 |
| 18 GG-Shafer-E_CO | 9,322 | 9,021 | 9,562 | 7,434 | 8,672 | No change | Within reasonable range | 9,322 |
| 19 CP-AltaLuna-S_NM | n/a | n/a | n/a | n/a | n/a | n/a | n/a | n/a |
| 20 CP-SanIsabel-E_CO | n/a | n/a | n/a | n/a | n/a | n/a | n/a | n/a |
| 21 CP-FirstSolar-N_NM | n/a | n/a | n/a | n/a | n/a | n/a | n/a | n/a |
| 22 CP-ColoHighlands-E_CO | n/a | n/a | n/a | n/a | n/a | n/a | n/a | n/a |
| 23 CP-KitCarson-E_CO | n/a | n/a | n/a | n/a | n/a | n/a | n/a | n/a |
| 24 CP-TwinButtes-E_CO | n/a | n/a | n/a | n/a | n/a | n/a | n/a | n/a |
| 25 CP-Carousel-E_CO | n/a | n/a | n/a | n/a | n/a | n/a | n/a | n/a |
| 26 CP-Basin_West | n/a | n/a | n/a | n/a | n/a | n/a | n/a | n/a |
| 27 CP-Basin_East | n/a | n/a | n/a | n/a | n/a | n/a | n/a | n/a |

*Table 4 – Results of Review – Variable O&M Cost ($/MWh)*

| | Resource | Non-Fuel Variable O&M Costs per MWh: Current Modeled | Tri-State Data | S&P Data | Peer Group Data (S&P) | Avg. Tri-State, S&P, Peer Group Data | Recommendation | Notes | Recommended Modeled |
|---|---|---|---|---|---|---|---|---|---|
| 1 | GC-Craig 1-NW_CO | [redacted] | None | 3.37 | 3.62 | 3.49 | No change | S&P data not actual | [redacted] |
| 2 | GC-Craig 2-NW_CO | | None | 3.37 | 3.62 | 3.49 | No change | S&P data not actual | |
| 3 | GC-Craig 3-NW_CO | | None | 3.37 | 3.62 | 3.49 | No change | S&P data not actual | |
| 4 | GC-LRS 2-WY | | None | 2.58 | 3.62 | 3.10 | No change | S&P data not actual | |
| 5 | GC-LRS 3-WY | | None | 2.58 | 3.62 | 3.10 | No change | S&P data not actual | |
| 6 | GC-SV 3-SPV | | None | 5.89 | 3.62 | 4.75 | No change | S&P data not actual | |
| 7 | GG-Burlington 1-E_CO | | None | 88.57 | 14.97 | 51.77 | No change | S&P data reflects extreme year | |
| 8 | GG-Burlington 2-E_CO | | None | 88.57 | 14.97 | 51.77 | No change | S&P data reflects extreme year | |
| 9 | GG-Knutson 1-E_CO | | None | 15.26 | 14.97 | 15.11 | No change | S&P data reflects extreme year | |
| 10 | GG-Knutson 2-E_CO | | None | 15.26 | 14.97 | 15.11 | No change | S&P data reflects extreme year | |
| 11 | GG-Limon 1-E_CO | | None | 5.67 | 14.97 | 10.32 | No change | S&P data reflects extreme year | |
| 12 | GG-Limon 2-E_CO | | None | 5.67 | 14.97 | 10.32 | No change | S&P data reflects extreme year | |
| 13 | GG-Pyramid 1-S_NM | | None | 6.49 | 8.69 | 7.59 | No change | S&P data not actual | |
| 14 | GG-Pyramid 2-S_NM | | None | 6.49 | 8.69 | 7.59 | No change | S&P data not actual | |
| 15 | GG-Pyramid 3-S_NM | | None | 6.49 | 8.69 | 7.59 | No change | S&P data not actual | |
| 16 | GG-Pyramid 4-S_NM | | None | 6.49 | 8.69 | 7.59 | No change | S&P data not actual | |
| 17 | GG-Rifle-NW_CO | | None | 8.32 | 3.23 | 5.77 | No change | Within reasonable range | |
| 18 | GG-Shafer-E_CO | | None | 3.75 | 1.63 | 2.69 | No change | S&P data skewed by 2017 value | |
| 19 | CP-AltaLuna-S_NM | n/a | n/a | n/a | n/a | n/a | n/a | n/a | n/a |
| 20 | CP-SanIsabel-E_CO | n/a | n/a | n/a | n/a | n/a | n/a | n/a | n/a |
| 21 | CP-FirstSolar-N_NM | n/a | n/a | n/a | n/a | n/a | n/a | n/a | n/a |
| 22 | CP-ColoHighlands-E_CO | n/a | n/a | n/a | n/a | n/a | n/a | n/a | n/a |
| 23 | CP-KitCarson-E_CO | n/a | n/a | n/a | n/a | n/a | n/a | n/a | n/a |
| 24 | CP-TwinButtes-E_CO | n/a | n/a | n/a | n/a | n/a | n/a | n/a | n/a |
| 25 | CP-Carousel-E_CO | n/a | n/a | n/a | n/a | n/a | n/a | n/a | n/a |
| 26 | CP-Basin_West | n/a | n/a | n/a | n/a | n/a | n/a | n/a | n/a |
| 27 | CP-Basin_East | n/a | n/a | n/a | n/a | n/a | n/a | n/a | n/a |

*Table 5 – Results of Review – Fixed O&M Costs ($/kw-yr)*

| | Fixed O&M Costs per kW-Year | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|
| Resource | Current Modeled | Tri-State Data | S&P Data | Peer Group Data (S&P) | Avg. Tri-State, S&P, Peer Group Data | Recommendation | Notes | Max Capacity (MW) | Recommended Modeled | Recommended Modeled ($000s) |
| 1 GC-Craig 1-NW_CO | [redacted] | None | 42.62 | 27.77 | 35.19 | No change | S&P data poor quality (duplicative, missing) | 102 | [redacted] | [redacted] |
| 2 GC-Craig 2-NW_CO | | None | 42.62 | 27.77 | 35.19 | No change | S&P data poor quality (duplicative, missing) | 98 | | |
| 3 GC-Craig 3-NW_CO | | None | 42.62 | 27.77 | 35.19 | No change | S&P data poor quality (duplicative, missing) | 448 | | |
| 4 GC-LRS 2-WY | | None | 28.01 | 27.77 | 27.89 | No change | S&P data poor quality (duplicative, missing) | 231 | | |
| 5 GC-LRS 3-WY | | None | 28.01 | 27.77 | 27.89 | No change | S&P data poor quality (duplicative, missing) | 230 | | |
| 6 GC-SV 3-SPV | | None | 49.73 | 27.77 | 38.75 | No change | S&P data poor quality (duplicative, missing) | 417 | | |
| 7 GG-Burlington 1-E_CO | | None | 4.68 | 3.55 | 4.12 | No change | S&P data poor quality (duplicative, missing) | 55 | | |
| 8 GG-Burlington 2-E_CO | | None | 4.68 | 3.55 | 4.12 | No change | S&P data poor quality (duplicative, missing) | 55 | | |
| 9 GG-Knutson 1-E_CO | | None | 3.62 | 3.55 | 3.58 | No change | S&P data poor quality (duplicative, missing) | 70 | | |
| 10 GG-Knutson 2-E_CO | | None | 3.62 | 3.55 | 3.58 | No change | S&P data poor quality (duplicative, missing) | 70 | | |
| 11 GG-Limon 1-E_CO | | None | 3.62 | 3.55 | 3.58 | No change | S&P data poor quality (duplicative, missing) | 70 | | |
| 12 GG-Limon 2-E_CO | | None | 3.62 | 3.55 | 3.58 | No change | S&P data poor quality (duplicative, missing) | 70 | | |
| 13 GG-Pyramid 1-S_NM | | None | 3.51 | 6.34 | 4.92 | No change | S&P data poor quality (duplicative, missing) | 55 | | |
| 14 GG-Pyramid 2-S_NM | | None | 3.51 | 6.34 | 4.92 | No change | S&P data poor quality (duplicative, missing) | 55 | | |
| 15 GG-Pyramid 3-S_NM | | None | 3.51 | 6.34 | 4.92 | No change | S&P data poor quality (duplicative, missing) | 70 | | |
| 16 GG-Pyramid 4-S_NM | | None | 3.51 | 6.34 | 4.92 | No change | S&P data poor quality (duplicative, missing) | 70 | | |
| 17 GG-Rifle-NW_CO | | None | 26.68 | 14.44 | 20.56 | 25.00 | Current modeled very high | 52 | | |
| 18 GG-Shafer-E_CO | | None | 14.64 | 11.08 | 12.86 | No change | Within reasonable range | 14 | | |
| 19 CP-AltaLuna-S_NM | n/a | n/a | n/a | n/a | n/a | n/a | n/a | n/a | n/a | n/a |
| 20 CP-SanIsabel-E_CO | n/a | n/a | n/a | n/a | n/a | n/a | n/a | n/a | n/a | n/a |
| 21 CP-FirstSolar-N_NM | n/a | n/a | n/a | n/a | n/a | n/a | n/a | n/a | n/a | n/a |
| 22 CP-ColoHighlands-E_CO | n/a | n/a | n/a | n/a | n/a | n/a | n/a | n/a | n/a | n/a |
| 23 CP-KitCarson-E_CO | n/a | n/a | n/a | n/a | n/a | n/a | n/a | n/a | n/a | n/a |
| 24 CP-TwinButtes-E_CO | n/a | n/a | n/a | n/a | n/a | n/a | n/a | n/a | n/a | n/a |
| 25 CP-Carousel-E_CO | n/a | n/a | n/a | n/a | n/a | n/a | n/a | n/a | n/a | n/a |
| 26 CP-Basin_West | n/a | n/a | n/a | n/a | n/a | n/a | n/a | n/a | n/a | n/a |
| 27 CP-Basin_East | n/a | n/a | n/a | n/a | n/a | n/a | n/a | n/a | n/a | n/a |

Notes:
Yellow highlight indicates average Tri-State, S&P and Peer Group value is more than 10% above/below current modeled value
Green highlight indicates recommended modeled value different than current modeled value
Grey highlight indicates user entered value

*Table 6 – Results of Review – CO2 Emission Rate (lb/MMBtu)*

| | | CO2 Emission Rate (lb/MMBtu) | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|
| | Resource | Current Modeled | Tri-State Data | S&P Data | Peer Group Data (S&P) | Avg. Tri-State, S&P, Peer Group Data | Recommendation | Notes | Recommended Modeled |
| 1 | GC-Craig 1-NW_CO | 224.80 | None | 209.76 | 208.80 | 209.28 | No change | Within reasonable range | 224.80 |
| 2 | GC-Craig 2-NW_CO | 229.96 | None | 209.76 | 208.80 | 209.28 | No change | Within reasonable range | 229.96 |
| 3 | GC-Craig 3-NW_CO | 206.21 | None | 209.76 | 208.80 | 209.28 | No change | Within reasonable range | 206.21 |
| 4 | GC-LRS 2-WY | 221.94 | None | 209.76 | 208.80 | 209.28 | No change | Within reasonable range | 221.94 |
| 5 | GC-LRS 3-WY | 234.01 | None | 209.76 | 208.80 | 209.28 | No change | S&P data not actual | 234.01 |
| 6 | GC-SV 3-SPV | 215.08 | None | 209.66 | 208.80 | 209.23 | No change | Within reasonable range | 215.08 |
| 7 | GG-Burlington 1-E_CO | 185.51 | None | 162.22 | 122.03 | 142.13 | No change | S&P data not actual | 185.51 |
| 8 | GG-Burlington 2-E_CO | 174.94 | None | 162.22 | 122.03 | 142.13 | No change | S&P data not actual | 174.94 |
| 9 | GG-Knutson 1-E_CO | 129.15 | None | 119.08 | 122.03 | 120.56 | No change | S&P data not actual | 129.15 |
| 10 | GG-Knutson 2-E_CO | 128.80 | None | 119.07 | 122.03 | 120.55 | No change | S&P data not actual | 128.80 |
| 11 | GG-Limon 1-E_CO | 128.63 | None | 120.09 | 122.03 | 121.06 | No change | S&P data not actual | 128.63 |
| 12 | GG-Limon 2-E_CO | 128.12 | None | 119.16 | 122.03 | 120.60 | No change | S&P data not actual | 128.12 |
| 13 | GG-Pyramid 1-S_NM | 127.28 | None | 120.20 | 118.98 | 119.59 | No change | Within reasonable range | 127.28 |
| 14 | GG-Pyramid 2-S_NM | 126.46 | None | 121.06 | 118.98 | 120.02 | No change | Within reasonable range | 126.46 |
| 15 | GG-Pyramid 3-S_NM | 128.31 | None | 122.74 | 118.98 | 120.86 | No change | Within reasonable range | 128.31 |
| 16 | GG-Pyramid 4-S_NM | 127.08 | None | 120.04 | 118.98 | 119.51 | No change | Within reasonable range | 127.08 |
| 17 | GG-Rifle-NW_CO | 113.15 | None | 118.40 | 116.81 | 117.61 | No change | Within reasonable range | 113.15 |
| 18 | GG-Shafer-E_CO | 105.24 | None | 118.86 | 118.67 | 118.77 | No change | S&P data not actual | 105.24 |
| 19 | CP-AltaLuna-S_NM | n/a | n/a | n/a | n/a | n/a | n/a | n/a | n/a |
| 20 | CP-SanIsabel-E_CO | n/a | n/a | n/a | n/a | n/a | n/a | n/a | n/a |
| 21 | CP-FirstSolar-N_NM | n/a | n/a | n/a | n/a | n/a | n/a | n/a | n/a |
| 22 | CP-ColoHighlands-E_CO | n/a | n/a | n/a | n/a | n/a | n/a | n/a | n/a |
| 23 | CP-KitCarson-E_CO | n/a | n/a | n/a | n/a | n/a | n/a | n/a | n/a |
| 24 | CP-TwinButtes-E_CO | n/a | n/a | n/a | n/a | n/a | n/a | n/a | n/a |
| 25 | CP-Carousel-E_CO | n/a | n/a | n/a | n/a | n/a | n/a | n/a | n/a |
| 26 | CP-Basin_West | 168.32 | n/a | n/a | n/a | n/a | n/a | n/a | 168.323 |
| 27 | CP-Basin_East | 123.81 | n/a | n/a | n/a | n/a | n/a | n/a | 123.805 |

Notes:
Yellow highlight indicates average Tri-State, S&P and Peer Group value is more than 10% above/below current modeled value
Green highlight indicates recommended modeled value different than current modeled value
Grey highlight indicates user entered value

BLACK & VEATCH

August 3, 2020 Revision

*Table 7 – Results of Review – NOx Emission Rate (lb/MMBtu)*

| | NOx Emission Rate (lb/MMBtu) | | | | | | | |
|---|---|---|---|---|---|---|---|---|
| Resource | Current Modeled | Tri-State Data | S&P Data | Peer Group Data (S&P) | Avg. Tri-State, S&P, Peer Group Data | Recommendation | Notes | Recommended Modeled |
| 1 GC-Craig 1-NW_CO | 0.269 | None | 0.249 | 0.139 | 0.194 | No change | S&P peer group data suspect | 0.27 |
| 2 GC-Craig 2-NW_CO | 0.066 | None | 0.197 | 0.139 | 0.168 | No change | Lower than Craig 1 due to NOx controls | 0.07 |
| 3 GC-Craig 3-NW_CO | 0.222 | None | 0.275 | 0.139 | 0.207 | No change | S&P peer group data suspect | 0.22 |
| 4 GC-LRS 2-WY | 0.235 | None | 0.153 | 0.139 | 0.146 | No change | S&P peer group data suspect | 0.23 |
| 5 GC-LRS 3-WY | 0.234 | None | 0.150 | 0.139 | 0.145 | No change | S&P data, peer group data suspect | 0.23 |
| 6 GC-SV 3-SPV | 0.079 | None | 0.077 | 0.139 | 0.108 | No change | S&P peer group data suspect | 0.08 |
| 7 GG-Burlington 1-E_CO | 1.047 | None | 0.301 | 0.202 | 0.252 | 0.300 | Current modeled very high | 0.30 |
| 8 GG-Burlington 2-E_CO | 1.030 | None | 0.301 | 0.202 | 0.252 | 0.300 | Current modeled very high | 0.30 |
| 9 GG-Knutson 1-E_CO | 0.030 | None | 0.029 | 0.202 | 0.115 | No change | S&P peer group data suspect | 0.03 |
| 10 GG-Knutson 2-E_CO | 0.029 | None | 0.030 | 0.202 | 0.116 | No change | S&P peer group data suspect | 0.03 |
| 11 GG-Limon 1-E_CO | 0.037 | None | 0.029 | 0.202 | 0.116 | No change | S&P peer group data suspect | 0.04 |
| 12 GG-Limon 2-E_CO | 0.028 | None | 0.029 | 0.202 | 0.116 | No change | S&P peer group data suspect | 0.03 |
| 13 GG-Pyramid 1-S_NM | 0.129 | None | 0.127 | 0.057 | 0.092 | No change | S&P peer group data suspect | 0.13 |
| 14 GG-Pyramid 2-S_NM | 0.120 | None | 0.118 | 0.057 | 0.087 | No change | S&P peer group data suspect | 0.12 |
| 15 GG-Pyramid 3-S_NM | 0.129 | None | 0.122 | 0.057 | 0.089 | No change | S&P peer group data suspect | 0.13 |
| 16 GG-Pyramid 4-S_NM | 0.125 | None | 0.125 | 0.057 | 0.091 | No change | S&P peer group data suspect | 0.13 |
| 17 GG-Rifle-NW_CO | 0.245 | None | 0.020 | 0.048 | 0.034 | 0.030 | Current modeled very high | 0.03 |
| 18 GG-Shafer-E_CO | 0.080 | None | 0.089 | 0.010 | 0.050 | No change | S&P peer group data suspect | 0.08 |
| 19 CP-AltaLuna-S_NM | n/a | n/a | n/a | n/a | n/a | n/a | n/a | n/a |
| 20 CP-SanIsabel-E_CO | n/a | n/a | n/a | n/a | n/a | n/a | n/a | n/a |
| 21 CP-FirstSolar-N_NM | n/a | n/a | n/a | n/a | n/a | n/a | n/a | n/a |
| 22 CP-ColoHighlands-E_CO | n/a | n/a | n/a | n/a | n/a | n/a | n/a | n/a |
| 23 CP-KitCarson-E_CO | n/a | n/a | n/a | n/a | n/a | n/a | n/a | n/a |
| 24 CP-TwinButtes-E_CO | n/a | n/a | n/a | n/a | n/a | n/a | n/a | n/a |
| 25 CP-Carousel-E_CO | n/a | n/a | n/a | n/a | n/a | n/a | n/a | n/a |
| 26 CP-Basin_West | 0.173 | n/a | n/a | n/a | n/a | n/a | n/a | 0.173 |
| 27 CP-Basin_East | 0.099 | n/a | n/a | n/a | n/a | n/a | n/a | 0.099 |

Notes:
Yellow highlight indicates average Tri-State, S&P and Peer Group value is more than 10% above/below current modeled value
Green highlight indicates recommended modeled value different than current modeled value
Grey highlight indicates user entered value

*Table 8 – Results of Review – SO2 Emission Rate (lb/MMBtu)*

| | SO2 Emission Rate (lb/MMBtu) | | | | | | | |
|---|---|---|---|---|---|---|---|---|
| Resource | Current Modeled | Tri-State Data | S&P Data | Peer Group Data (S&P) | Avg. Tri-State, S&P, Peer Group Data | Recommendation | Notes | Recommended Modeled |
| GC-Craig 1-NW_CO | 0.0366 | None | 0.042 | 0.187 | 0.1148 | No change | S&P peer group data suspect | 0.0366 |
| GC-Craig 2-NW_CO | 0.0338 | None | 0.043 | 0.187 | 0.1151 | No change | S&P peer group data suspect | 0.0338 |
| GC-Craig 3-NW_CO | 0.1291 | None | 0.131 | 0.187 | 0.1592 | No change | S&P peer group data suspect | 0.1291 |
| GC-LRS 2-WY | 0.1109 | None | 0.098 | 0.187 | 0.1427 | No change | S&P peer group data suspect | 0.1109 |
| GC-LRS 3-WY | 0.1772 | None | 0.112 | 0.187 | 0.1496 | No change | Modeled rate based on permit. S&P peer group data suspect | 0.1772 |
| GC-SV 3-SPV | 0.0843 | None | 0.073 | 0.187 | 0.1298 | No change | S&P peer group data suspect | 0.0843 |
| GG-Burlington 1-E_CO | 0.0173 | None | 0.075 | 0.014 | 0.0443 | No change | S&P data suspect | 0.0173 |
| GG-Burlington 2-E_CO | 0.0153 | None | 0.075 | 0.014 | 0.0443 | No change | S&P data suspect | 0.0153 |
| GG-Knutson 1-E_CO | 0.0007 | None | 0.001 | 0.014 | 0.0071 | No change | S&P peer group data suspect | 0.0007 |
| GG-Knutson 2-E_CO | 0.0008 | None | 0.001 | 0.014 | 0.0071 | No change | S&P peer group data suspect | 0.0008 |
| GG-Limon 1-E_CO | 0.0007 | None | 0.001 | 0.014 | 0.0072 | No change | S&P peer group data suspect | 0.0007 |
| GG-Limon 2-E_CO | 0.0007 | None | 0.001 | 0.014 | 0.0071 | No change | S&P peer group data suspect | 0.0007 |
| GG-Pyramid 1-S_NM | 0.0013 | None | 0.001 | 0.001 | 0.0011 | No change | S&P peer group data suspect | 0.0013 |
| GG-Pyramid 2-S_NM | 0.0017 | None | 0.002 | 0.001 | 0.0014 | No change | S&P peer group data suspect | 0.0017 |
| GG-Pyramid 3-S_NM | 0.0012 | None | 0.003 | 0.001 | 0.0017 | No change | S&P peer group data suspect | 0.0012 |
| GG-Pyramid 4-S_NM | 0.0006 | None | 0.001 | 0.001 | 0.0011 | No change | S&P peer group data suspect | 0.0006 |
| GG-Rifle-NW_CO | 0.0001 | None | 0.001 | 0.004 | 0.0026 | 0.0010 | Current modeled data very low | 0.0010 |
| GG-Shafer-E_CO | 0.0008 | None | 0.001 | 0.001 | 0.0006 | 0.0010 | Current modeled data very low | 0.0010 |
| CP-AltaLuna-S_NM | n/a | n/a | n/a | n/a | n/a | n/a | n/a | n/a |
| CP-SanIsabel-E_CO | n/a | n/a | n/a | n/a | n/a | n/a | n/a | n/a |
| CP-FirstSolar-N_NM | n/a | n/a | n/a | n/a | n/a | n/a | n/a | n/a |
| CP-ColoHighlands-E_CO | n/a | n/a | n/a | n/a | n/a | n/a | n/a | n/a |
| CP-KitCarson-E_CO | n/a | n/a | n/a | n/a | n/a | n/a | n/a | n/a |
| CP-TwinButtes-E_CO | n/a | n/a | n/a | n/a | n/a | n/a | n/a | n/a |
| CP-Carousel-E_CO | n/a | n/a | n/a | n/a | n/a | n/a | n/a | n/a |
| CP-Basin_West | 0.107 | n/a | n/a | n/a | n/a | n/a | n/a | 0.107 |
| CP-Basin_East | 0.139 | n/a | n/a | n/a | n/a | n/a | n/a | 0.139 |

Notes:
Yellow highlight indicates average Tri-State, S&P and Peer Group value is more than 10% above/below current modeled value
Green highlight indicates recommended modeled value different than current modeled value
Grey highlight indicates user entered value





*Table 9 – Results of Review – Annual Availability Factor (%)*

| | Availability Factor (%) | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|
| Resource | Current Modeled | Tri-State Data | S&P Data | Peer Group Data (NERC) | Avg. Tri-State, Peer Group Data (5% Sig.) | Recommendation | Notes | Recommended Modeled | Resulting Modeled MOH |
| 1 GC-Craig 1-NW_CO | 95.81 | 91.63 | None | 88.83 | 90.23 | No change | Tri-State data skewed by low 2016 value | 95.81 | 367 |
| 2 GC-Craig 2-NW_CO | 93.70 | 90.37 | None | 88.83 | 89.60 | No change | Within reasonable range | 93.70 | 552 |
| 3 GC-Craig 3-NW_CO | 92.88 | 78.77 | None | 88.83 | 83.80 | No change | Tri-State data skewed by low 2016 value | 92.88 | 624 |
| 4 GC-LRS 2-WY | 91.66 | 91.28 | None | 88.83 | 90.05 | No change | Within reasonable range | 91.66 | 731 |
| 5 GC-LRS 3-WY | 91.93 | 91.96 | None | 88.83 | 90.39 | No change | Within reasonable range | 91.93 | 707 |
| 6 GC-SV 3-SPV | 93.70 | 87.31 | None | 88.83 | 88.07 | No change | Tri-State data skewed by low 2016 value | 93.70 | 552 |
| 7 GG-Burlington 1-E_CO | 99.27 | 97.74 | None | 90.23 | 93.99 | 98 | Current modeled too high | 98.00 | 175 |
| 8 GG-Burlington 2-E_CO | 99.78 | 98.65 | None | 90.23 | 94.44 | 99 | Current modeled too high | 99.00 | 88 |
| 9 GG-Knutson 1-E_CO | 99.56 | 96.46 | None | 90.23 | 93.34 | 96 | Current modeled too high | 96.00 | 350 |
| 10 GG-Knutson 2-E_CO | 99.56 | 95.32 | None | 90.23 | 92.78 | No change | Tri-State data skewed by low 2018 value | 99.56 | 38 |
| 11 GG-Limon 1-E_CO | 99.56 | 96.39 | None | 90.23 | 93.31 | 96 | Current modeled too high | 96.00 | 350 |
| 12 GG-Limon 2-E_CO | 99.56 | 91.59 | None | 90.23 | 90.91 | No change | Tri-State data skewed by low 2018 value | 99.56 | 38 |
| 13 GG-Pyramid 1-S_NM | 98.55 | 98.61 | None | 90.23 | 94.42 | No change | Within reasonable range | 98.55 | 127 |
| 14 GG-Pyramid 2-S_NM | 98.42 | 98.69 | None | 90.23 | 94.46 | No change | Within reasonable range | 98.42 | 139 |
| 15 GG-Pyramid 3-S_NM | 98.42 | 98.90 | None | 90.23 | 94.57 | No change | Within reasonable range | 98.42 | 139 |
| 16 GG-Pyramid 4-S_NM | 98.55 | 99.07 | None | 90.23 | 94.65 | No change | Within reasonable range | 98.55 | 127 |
| 17 GG-Rifle-NW_CO | 99.74 | 89.98 | None | 87.91 | 88.95 | 90 | Current modeled too high | 90.00 | 876 |
| 18 GG-Shafer-E_CO | 99.91 | 89.89 | None | 86.31 | 88.10 | 90 | Current modeled too high | 90.00 | 876 |
| 19 CP-AltaLuna-S_NM | n/a | n/a | n/a | n/a | n/a | n/a | n/a | n/a | n/a |
| 20 CP-SanIsabel-E_CO | n/a | n/a | n/a | n/a | n/a | n/a | n/a | n/a | n/a |
| 21 CP-FirstSolar-N_NM | n/a | n/a | n/a | n/a | n/a | n/a | n/a | n/a | n/a |
| 22 CP-ColoHighlands-E_CO | n/a | n/a | n/a | n/a | n/a | n/a | n/a | n/a | n/a |
| 23 CP-KitCarson-E_CO | n/a | n/a | n/a | n/a | n/a | n/a | n/a | n/a | n/a |
| 24 CP-TwinButtes-E_CO | n/a | n/a | n/a | n/a | n/a | n/a | n/a | n/a | n/a |
| 25 CP-Carousel-E_CO | n/a | n/a | n/a | n/a | n/a | n/a | n/a | n/a | n/a |
| 26 CP-Basin_West | n/a | n/a | n/a | n/a | n/a | n/a | n/a | n/a | n/a |
| 27 CP-Basin_East | n/a | n/a | n/a | n/a | n/a | n/a | n/a | n/a | n/a |

Notes:
Yellow highlight indicates average Tri-State, S&P and Peer Group value is more than 10% above/below current modeled value
Green highlight indicates recommended modeled value different than current modeled value
Grey highlight indicates user entered value

*Table 10 – Results of Review – Annual Forced Outage Factor (%)*

| | Forced Outage Factor (%) | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|
| Resource | Current Modeled | Tri-State Data | S&P Data | Peer Group Data (NERC) | Avg. Tri-State, Peer Group Data (5% Sig.) | Recommendation | Notes | Recommended Modeled | Resulting Modeled FOH |
| 1 GC-Craig 1-NW_CO | 4.00 | 3.52 | None | 4.53 | 4.03 | No Change | Within reasonable range | 4.00 | 350 |
| 2 GC-Craig 2-NW_CO | 4.00 | 2.70 | None | 4.53 | 3.62 | No Change | Within reasonable range | 4.00 | 350 |
| 3 GC-Craig 3-NW_CO | 4.00 | 15.93 | None | 4.53 | 10.23 | No Change | Tri-State data skewed by 2018 45% | 4.00 | 350 |
| 4 GC-LRS 2-WY | 4.00 | 3.01 | None | 4.53 | 3.77 | No Change | Within reasonable range | 4.00 | 350 |
| 5 GC-LRS 3-WY | 4.00 | 3.53 | None | 4.53 | 4.03 | No Change | Within reasonable range | 4.00 | 350 |
| 6 GC-SV 3-SPV | 4.00 | 10.21 | None | 4.53 | 7.37 | No Change | Tri-State data skewed by 2016, 2017 15% | 4.00 | 350 |
| 7 GG-Burlington 1-E_CO | 0.00 | 1.23 | None | 3.85 | 2.54 | 1.00 | Modeled too low. Use Tri-State data. | 1.00 | 88 |
| 8 GG-Burlington 2-E_CO | 0.22 | 0.92 | None | 3.85 | 2.38 | 1.00 | Modeled too low. Use Tri-State data. | 1.00 | 88 |
| 9 GG-Knutson 1-E_CO | 0.44 | 0.51 | None | 3.85 | 2.18 | 1.00 | Modeled too low. Use Tri-State data. | 1.00 | 88 |
| 10 GG-Knutson 2-E_CO | 0.44 | 0.52 | None | 3.85 | 2.18 | 1.00 | Modeled too low. Use Tri-State data. | 1.00 | 88 |
| 11 GG-Limon 1-E_CO | 0.44 | 1.00 | None | 3.85 | 2.43 | 1.00 | Modeled too low. Use Tri-State data. | 1.00 | 88 |
| 12 GG-Limon 2-E_CO | 0.44 | 0.70 | None | 3.85 | 2.27 | 1.00 | Modeled too low. Use Tri-State data. | 1.00 | 88 |
| 13 GG-Pyramid 1-S_NM | 0.44 | 0.24 | None | 3.85 | 2.05 | 1.00 | Modeled too low. Use Tri-State data. | 1.00 | 88 |
| 14 GG-Pyramid 2-S_NM | 0.44 | 0.88 | None | 3.85 | 2.36 | 1.00 | Modeled too low. Use Tri-State data. | 1.00 | 88 |
| 15 GG-Pyramid 3-S_NM | 0.44 | 0.31 | None | 3.85 | 2.08 | 1.00 | Modeled too low. Use Tri-State data. | 1.00 | 88 |
| 16 GG-Pyramid 4-S_NM | 0.44 | 0.19 | None | 3.85 | 2.02 | 1.00 | Modeled too low. Use Tri-State data. | 1.00 | 88 |
| 17 GG-Rifle-NW_CO | 0.26 | 3.27 | None | 4.50 | 3.89 | 3.00 | Modeled too low. Use Tri-State data. | 3.00 | 263 |
| 18 GG-Shafer-E_CO | 0.09 | 2.93 | None | 3.93 | 3.43 | 3.00 | Modeled too low. Use Tri-State data. | 3.00 | 263 |
| 19 CP-AltaLuna-S_NM | n/a | n/a | n/a | n/a | n/a | n/a | n/a | n/a | n/a |
| 20 CP-SanIsabel-E_CO | n/a | n/a | n/a | n/a | n/a | n/a | n/a | n/a | n/a |
| 21 CP-FirstSolar-N_NM | n/a | n/a | n/a | n/a | n/a | n/a | n/a | n/a | n/a |
| 22 CP-ColoHighlands-E_CO | n/a | n/a | n/a | n/a | n/a | n/a | n/a | n/a | n/a |
| 23 CP-KitCarson-E_CO | n/a | n/a | n/a | n/a | n/a | n/a | n/a | n/a | n/a |
| 24 CP-TwinButtes-E_CO | n/a | n/a | n/a | n/a | n/a | n/a | n/a | n/a | n/a |
| 25 CP-Carousel-E_CO | n/a | n/a | n/a | n/a | n/a | n/a | n/a | n/a | n/a |
| 26 CP-Basin_West | n/a | n/a | n/a | n/a | n/a | n/a | n/a | n/a | n/a |
| 27 CP-Basin_East | n/a | n/a | n/a | n/a | n/a | n/a | n/a | n/a | n/a |

Notes:
Yellow highlight indicates average Tri-State, S&P and Peer Group value is more than 10% above/below current modeled value
Green highlight indicates recommended modeled value different than current modeled value
Grey highlight indicates user entered value

*Table 11 – Results of Review – Annual Renewable Capacity Factor*

| | Resource | Renewable Capacity Factor (%) Current Modeled | Tri-State Data | S&P Data | Peer Group Data (S&P) | Avg. Tri-State, Peer Group Data | Recommendation | Notes | Recommended Modeled |
|---|---|---|---|---|---|---|---|---|---|
| 1 | GC-Craig 1-NW_CO | n/a | n/a | n/a | n/a | n/a | n/a | n/a | n/a |
| 2 | GC-Craig 2-NW_CO | n/a | n/a | n/a | n/a | n/a | n/a | n/a | n/a |
| 3 | GC-Craig 3-NW_CO | n/a | n/a | n/a | n/a | n/a | n/a | n/a | n/a |
| 4 | GC-LRS 2-WY | n/a | n/a | n/a | n/a | n/a | n/a | n/a | n/a |
| 5 | GC-LRS 3-WY | n/a | n/a | n/a | n/a | n/a | n/a | n/a | n/a |
| 6 | GC-SV 3-SPV | n/a | n/a | n/a | n/a | n/a | n/a | n/a | n/a |
| 7 | GG-Burlington 1-E_CO | n/a | n/a | n/a | n/a | n/a | n/a | n/a | n/a |
| 8 | GG-Burlington 2-E_CO | n/a | n/a | n/a | n/a | n/a | n/a | n/a | n/a |
| 9 | GG-Knutson 1-E_CO | n/a | n/a | n/a | n/a | n/a | n/a | n/a | n/a |
| 10 | GG-Knutson 2-E_CO | n/a | n/a | n/a | n/a | n/a | n/a | n/a | n/a |
| 11 | GG-Limon 1-E_CO | n/a | n/a | n/a | n/a | n/a | n/a | n/a | n/a |
| 12 | GG-Limon 2-E_CO | n/a | n/a | n/a | n/a | n/a | n/a | n/a | n/a |
| 13 | GG-Pyramid 1-S_NM | n/a | n/a | n/a | n/a | n/a | n/a | n/a | n/a |
| 14 | GG-Pyramid 2-S_NM | n/a | n/a | n/a | n/a | n/a | n/a | n/a | n/a |
| 15 | GG-Pyramid 3-S_NM | n/a | n/a | n/a | n/a | n/a | n/a | n/a | n/a |
| 16 | GG-Pyramid 4-S_NM | n/a | n/a | n/a | n/a | n/a | n/a | n/a | n/a |
| 17 | GG-Rifle-NW_CO | n/a | n/a | n/a | n/a | n/a | n/a | n/a | n/a |
| 18 | GG-Shafer-E_CO | n/a | n/a | n/a | n/a | n/a | n/a | n/a | n/a |
| 19 | CP-AltaLuna-S_NM | 35 | 33 | 31 | 23 | 29 | No Change | Peer group data suspect, very low | 35 |
| 20 | CP-SanIsabel-E_CO | 29 | 19 | 19 | 35 | 29 | No Change | Within reasonable range | 29 |
| 21 | CP-FirstSolar-N_NM | 22 | 24 | 24 | 29 | 29 | No Change | Peer group data suspect, very high | 22 |
| 22 | CP-ColoHighlands-E_CO | 46 | 45 | 44 | 32 | 41 | No Change | Peer group data suspect, very low | 46 |
| 23 | CP-KitCarson-E_CO | 42 | 40 | 40 | 32 | 37 | No Change | Peer group data suspect, very low | 42 |
| 24 | CP-TwinButtes-E_CO | 45 | 28 | 23 | 32 | 28 | No Change | Tri-State, S&P data skewed by low 2017 | 45 |
| 25 | CP-Carousel-E_CO | 51 | 37 | 37 | 32 | 35 | No Change | Tri-State, S&P data skewed by low 2015 | 51 |
| 26 | CP-Basin_West | n/a | n/a | n/a | n/a | n/a | n/a | n/a | n/a |
| 27 | CP-Basin_East | n/a | n/a | n/a | n/a | n/a | n/a | n/a | n/a |

Notes:
Yellow highlight indicates average Tri-State, S&P and Peer Group value is more than 10% above/below current modeled value
Green highlight indicates recommended modeled value different than current modeled value
Grey highlight indicates user entered value




**END OF REPORT**

# Appendix B: Black & Veatch Report on Benchmarking of Existing Resources

BLACK & VEATCH

August 3, 2020 Revision

# Report on Benchmarking of Existing Resources

## Executive Summary

As part of its responsibilities under a recent Energy Resource Planning decision by the Colorado Public Utilities Commission[1], Tri-State Generation & Transmission Association ("Tri-State") must file in support of its Energy Resource Plan (ERP) an assessment of its existing resources including a comparison of the costs and performance of each of its existing resources (utility owned and contracted) to the costs and performance of the generic resources (a "Benchmarking")[2]. Tri-State retained Black & Veatch ("we" or "us") to perform the Benchmarking for the purposes of supporting a filing by Tri-State. Tri-State defined the existing resources to include eighteen (18) of its coal, gas and oil fired resources, two (2) long-term purchase agreements with Basin Electric, and seven (7) of its renewable (solar and wind) facilities totaling twenty seven (27) existing resources ("Existing Resources"). Tri-State did not include its renewable facilities that are under contract but not yet in commercial operation. The generic resources included future potential gas-fired, solar, wind, battery storage, solar plus battery, wind plus battery, and hydroelectric resources located in Colorado, Wyoming and New Mexico totaling sixty one (61) generic resources ("Generic Resources"). This Report summarizes the scope, methodology and results of the Benchmarking.

Our approach was to first identify for each Existing Resource a Generic Resource for comparison based on the type of Existing Resource (thermal or renewable), the location of the Existing Resource, the generating capacity of the Existing Resource, and the annual capacity factor typically expected for a resource of that type. We then forecast the annual energy production and costs of both the Existing Resource and the Generic Resource for the years 2021-2040 assuming each operated at the same capacity factor in isolation from all other resources and under common assumptions for the Colorado social cost of carbon ("Social Cost of Carbon"), fuel costs, interest rates and escalation. Assumptions for heat rate, fixed O&M, variable O&M, capital basis, depreciation, and book life were specific to each resource and were provided by Tri-State. We developed assumptions for a limited number of the Generic Resources where necessary. The forecasts were made on an "equal service life" basis ensuring the Existing Resource and Generic Resource operated for the same years in the study period at the same capacity factor. We then discounted the annual capacity, energy production and annual cost streams to net present values and expressed them as a levelized cost of energy in $/MWh (LCOE) for cases where the capacity factor was relatively high or a levelized cost of capacity in $/kw-yr (LCOC) where the capacity factor was relatively low.

[1] Colorado Public Utilities Decision No. C20-0155 issued March 10, 2020 adopting amendments to the provisions in the rules governing Electric Resource Planning (ERP Rules).

[2] Colorado Department of Regulatory Agencies, Public Utilities Commission, Code of Colorado Regulations (CCR) 723-3, Part 3 Rules Regulating Electric Utilities, Electric Resource Planning, Section 3605 (c)(II).

Results of the Benchmarking show that each coal-fired Existing Resource is more costly than its associated Generic Resource counterpart due primarily to higher Social Cost of Carbon and higher FOM costs. Each oil and gas fired combustion turbine Existing Resource is less costly than its Generic Resource counterpart due primarily to a lower (highly depreciated) capital basis and therefore lower depreciation and interest costs. Each renewable Existing Resource is more costly than its associated Generic Resource counterpart likely due to the fact that the Existing Resources were built in prior years when the cost of solar and wind technology was higher than today and much higher than costs expected in future years (a declining capital cost curve). The Basin West Contract is more costly than its Generic Resources due to an applied social cost of carbon rate, whereas conversely the Basin East Contract is less costly than its Generic Resources due to the need to include a gas-fired peaking resource in the Generic Resources to account for renewable intermittency. Results are shown in the Results section of this Report.

We also performed a supplemental analysis concerning the Existing Resources not located in Colorado to examine how their LCOE and LCOC would change if the Social Cost of Carbon was not applied ("Non-Colorado Benchmarking"). Results of the Non-Colorado Benchmarking revealed that both the Non-Colorado Existing Resources and the Non-Colorado Generic Resources are significantly less costly than under the Benchmarking. Results also revealed that although the Existing Resources are still more costly than the Generic Resources the gap in cost is narrowed significantly. This is particularly true for LRS Units 2 and 3 where the cost difference is narrowed to approximately ten (10) percent.

## Scope

The scope of the resources to be Benchmarked was defined by Tri-State and included the Existing Resources shown in Table 1 and the Generic Resources shown in Table 2 below.

### Existing Resources

Six (6) of the Existing Resources are coal fired. These include the Craig coal-fired Units 1 through 3 located in western Colorado ("wco"), the Laramie River coal-fired station ("LRS") Units 2 and 3 located in Wyoming ("wyo"), and Springerville coal-fired Unit 3 located in Arizona ("arz"). These resources are either partially owned or partially controlled by Tri-State with the exception of Craig Unit 3 which is wholly owned, and Springerville Unit 3 which is wholly leased with 100 MW of the Total Capacity sold to a third party under a tolling agreement through the summer of 2036. The capacity currently controlled by Tri-State is shown as the "Tri-State Modeled Capacity".

Another ten (10) the Existing Resources are oil or gas fired combustion turbines that are fully owned by Tri-State. These include the Burlington Units 1 and 2, the Knutson Units 1 and 2, and the Limon Units 1 and 2and the Pyramid Units 1 through 4. The Burlington, Knutson and Limon Units are located in eastern Colorado and the Pyramid Units are located in southern New Mexico. All of these resources are fully controlled by Tri-State

Another two (2) of the Existing Resources are gas-fired combined cycle plants that are fully owned by Tri-State. These include the Rifle plant located in western Colorado and the Shafer plant located in eastern Colorado.

These coal, gas or oil fired resources are referred to collectively as the "thermal" resources.

Another seven (7) Existing Resources are solar or wind powered "renewable" resources with output purchased by Tri-State under power purchase agreements ("PPA"). Five (5) of these resources are located in eastern Colorado ("eco") and the remaining two (2) are located in New Mexico. All of the output is purchased by Tri-State.

The remaining two (2) Existing Resources are long-term contract purchases from Basin Electric Power Cooperative ("Basin"), collectively the "Basin Contracts". The first contract is known as the Western CROD Contract ("Basin West") and the other as the Basin Electrically East Contract ("Basin East"). No specific generating resource is associated with each Basin Contract. Basin has the sole discretion to choose how the Basin West contract is supplied on a day ahead and hour ahead basis. The Basin East contract is supplied via Southwest Power Pool (SPP). The Basin West contract has a set hourly energy profile by month for each year of the contract. The Basin East Contract is a full requirements contract and supply is based on actual energy needs of Tri-State's Utility Member Systems located in the Eastern Interconnection. Tri-State purchases all energy as contracted under the Basin Contracts.

*Table 1 – Summary of Existing Resources to be Benchmarked*

| | Plant/Unit | Technology | Type | Location | Nominal Capacity (MW) | Tri-State Modeled Capacity (MW) | Year In Service |
|---|---|---|---|---|---|---|---|
| 1 | GC-Craig 1-NW_CO | Steam Turbine - Coal | Owned | wco | 427 | 102 | 1980 |
| 2 | GC-Craig 2-NW_CO | Steam Turbine - Coal | Owned | wco | 410 | 98 | 1979 |
| 3 | GC-Craig 3-NW_CO | Steam Turbine - Coal | Owned | wco | 448 | 448 | 1984 |
| 4 | GC-LRS 2-WY | Steam Turbine - Coal | Owned | wyo | 570 | 231 | 1981 |
| 5 | GC-LRS 3-WY | Steam Turbine - Coal | Owned | wyo | 570 | 230 | 1982 |
| 6 | GC-SV 3-SPV | Steam Turbine - Coal | Owned | arz | 417 | 317 | 2006 |
| 7 | GG-Burlington 1-E_CO | Frame CT - Oil | Owned | eco | 55 | 55 | 1977 |
| 8 | GG-Burlington 2-E_CO | Frame CT - Oil | Owned | eco | 55 | 55 | 1977 |
| 9 | GG-Knutson 1-E_CO | Frame CT - Gas | Owned | eco | 70 | 70 | 2002 |
| 10 | GG-Knutson 2-E_CO | Frame CT - Gas | Owned | eco | 70 | 70 | 2002 |
| 11 | GG-Limon 1-E_CO | Frame CT - Gas | Owned | eco | 70 | 70 | 2003 |
| 12 | GG-Limon 2-E_CO | Frame CT - Gas | Owned | eco | 70 | 70 | 2003 |
| 13 | GG-Pyramid 1-S_NM | Aeroderivative CT - Gas | Owned | snm | 40 | 40 | 2003 |
| 14 | GG-Pyramid 2-S_NM | Aeroderivative CT - Gas | Owned | snm | 40 | 40 | 2003 |
| 15 | GG-Pyramid 3-S_NM | Aeroderivative CT - Gas | Owned | snm | 40 | 40 | 2003 |

| | Plant/Unit | Technology | Type | Location | Nominal Capacity (MW) | Tri-State Modeled Capacity (MW) | Year In Service |
|---|---|---|---|---|---|---|---|
| 16 | GG-Pyramid 4-S_NM | Aeroderivative CT - Gas | Owned | snm | 40 | 40 | 2003 |
| 17 | GG-Rifle-NW_CO | Combined Cycle - Gas | Owned | wco | 81 | 81 | 1987 |
| 18 | GG-Shafer-E_CO | Combined Cycle - Gas | Owned | eco | 272 | 272 | 1994 |
| 19 | CP-AltaLuna-S_NM | Tracking Array Solar | PPA | nm | 25 | 25 | 2017 |
| 20 | CP-SanIsabel-E_CO | Tracking Array Solar | PPA | eco | 30 | 30 | 2016 |
| 21 | CP-FirstSolar-N_NM | Fixed Solar | PPA | nm | 30 | 30 | 2010 |
| 22 | CP-ColoHighlands-E_CO | Wind | PPA | eco | 91 | 91 | 2012 |
| 23 | CP-KitCarson-E_CO | Wind | PPA | eco | 51 | 51 | 2010 |
| 24 | CP-TwinButtes-E_CO | Wind | PPA | eco | 76 | 76 | 2017 |
| 25 | CP-Carousel-E_CO | Wind | PPA | eco | 150 | 150 | 2015 |
| 26 | CP-Basin_West | Basin System | PPA | eco | 268 | 268 | 2017 |
| 27 | CP-Basin_East | Basin System | PPA | eco | 317 | 317[3] | 2017 |

## Generic Resources

Twenty-eight (28) of the Generic Resources were gas-fired including reciprocating engine ("Recip_Engine"), aeroderivative combustion turbine ("Aeroderivative_CT"), industrial combustion turbine ("Frame_CT") and industrial combined cycle ("Frame_CCCT") technologies that would be located in western Colorado ("wco"), southwestern Colorado ("swco"), northwestern Colorado ("nwco"), northern New Mexico ("nnm") and Wyoming ("wyo"). All of these would be wholly owned by Tri-State with the capacity shown as the "Tri-State Modeled Capacity".

The remaining Generic Resources included:

- Solar PV ("Solar_PV") technologies of various sizes (40, 100, 120, 230 MW) and wind ("Wind") technologies of various sizes (40, 100, 165, 280 MW) to be located in eco, swco, nnm, and wyo either under third party ownership ("PPA") or Tri-State ownership ("Build-Transfer");
- Standalone lithium ion battery storage technology ("Li-Ion Battery") in various combinations of size (25, 100, 500 MW) and duration (4 hour or 8 hour) to be located in eco, swco, wco, nnm, and wyo to be owned ("Owned") by Tri-State;
- 300 MW pumped storage technology located in nnm to be owned by Tri-State;
- 100 MW combined solar PV plus storage ("Solar+Battery") and wind plus storage ("Wind+Battery") technologies to be located in eco, nnm, wyo and swco either under third party ownership or Tri-State ownership

[3] Basin East is a full requirements contract so capacity is not specified in the contract but rather fluctuates with the demand forecast of the members.

*Table 2 – Summary of Generic Resources to be Considered in the Benchmarking*

| | Name | Technology | Type | Location | Modeled Tri-State Capacity (MW) |
|---|---|---|---|---|---|
| 1 | 112_18x6RICE_eco | Recip_Engine | Owned | eco | 112 |
| 2 | 112_18x6RICE_nnm | Recip_Engine | Owned | nnm | 112 |
| 3 | 46_9x5RICE_eco | Recip_Engine | Owned | eco | 46 |
| 4 | 46_9x5RICE_nnm | Recip_Engine | Owned | nnm | 46 |
| 5 | 46_9x5RICE_swco | Recip_Engine | Owned | swco | 46 |
| 6 | Upd-93_10x9_3ICE_eco | Recip_Engine | Owned | eco | 93 |
| 7 | Upd-93_10x9_3ICE_nnm | Recip_Engine | Owned | nnm | 93 |
| 8 | Upd-93_10x9_3ICE_swco | Recip_Engine | Owned | swco | 93 |
| 9 | Upd-93_10x9_3ICE_wyo | Recip_Engine | Owned | wyo | 93 |
| 10 | 40_1x40LM6000_eco | Aeroderivative_CT | Owned | eco | 40 |
| 11 | 40_1x40LM6000_nnm | Aeroderivative_CT | Owned | nnm | 40 |
| 12 | 40_1x40LM6000_swco | Aeroderivative_CT | Owned | swco | 40 |
| 13 | 81_2x40LM6000_eco | Aeroderivative_CT | Owned | eco | 81 |
| 14 | 81_2x40LM6000_wyo | Aeroderivative_CT | Owned | wyo | 81 |
| 15 | 93_1x100_LMS100_nnm | Aeroderivative_CT | Owned | nnm | 93 |
| 16 | 300_1x1_7FA05_eco | Frame_CCCT | Owned | eco | 300 |
| 17 | 300_1x1_7FA05_nnm | Frame_CCCT | Owned | nnm | 300 |
| 18 | 300_1x1_7FA05_swco | Frame_CCCT | Owned | swco | 300 |
| 19 | 300_1x1_7FA05_wyo | Frame_CCCT | Owned | wyo | 300 |
| 20 | 287_1x1_M501G_nwco | Frame_CCCT | Owned | nwco | 350 |
| 21 | 331_1x1_STG-8000H_nwco | Frame_CCCT | Owned | nwco | 375 |
| 22 | 357_1x1_7HA01_nwco | Frame_CCCT | Owned | nwco | 357 |
| 23 | 545_1x1_7HA03_nwco | Frame_CCCT | Owned | nwco | 545 |
| 24 | 200_1x235_7FA05_eco | Frame_CT | Owned | eco | 200 |
| 25 | 200_1x235_7FA05_nnm | Frame_CT | Owned | nnm | 200 |
| 26 | 200_1x235_7FA05_swco | Frame_CT | Owned | swco | 200 |
| 27 | CP-1x100PV_eco | Solar_PV | PPA | eco | 100 |
| 28 | CP-1x100PV_nnm | Solar_PV | PPA | nnm | 100 |
| 29 | CP-1x100PV_swco | Solar_PV | PPA | swco | 100 |
| 30 | CP-1x100PV_eco Build-Transfer | Solar_PV | Owned | eco | 100 |
| 31 | CP-1x100PVBatt_eco | Solar+Battery | PPA | eco | 100 |
| 32 | CP-1x100PVBatt_nnm | Solar+Battery | PPA | nnm | 100 |
| 33 | CP-1x100PVBatt_swco | Solar+Battery | PPA | swco | 100 |
| 34 | CP-1x100PVBatt_eco Build-Transfer | Solar+Battery | Owned | eco | 100 |
| 35 | CP-1x100Wind_eco | Wind | PPA | eco | 100 |
| 36 | CP-1x100Wind_nnm | Wind | PPA | nnm | 100 |
| 37 | CP-1x100Wind_wyo | Wind | PPA | wyo | 100 |
| 38 | CP-1x100Wind_eco Build-Transfer | Wind | Owned | eco | 100 |
| 39 | CP-1x100WindBatt_eco | Wind+Battery | PPA | eco | 100 |
| 40 | CP-1x100WindBatt_nnm | Wind+Battery | PPA | nnm | 100 |
| 41 | CP-1x100WindBatt_wyo | Wind+Battery | PPA | wyo | 100 |
| 42 | 100MW Li-Ion Battery_eco | Li-Ion_Battery | Owned | eco | 100 |
| 43 | 100MW Li-Ion Battery_wco | Li-Ion_Battery | Owned | wco | 100 |
| 44 | 100MW Li-Ion Battery_nnm | Li-Ion_Battery | Owned | nnm | 100 |

| | Name | Technology | Type | Location | Modeled Tri-State Capacity (MW) |
|---|---|---|---|---|---|
| 45 | 25MW Li-Ion Battery_eco | Li-Ion_Battery | Owned | eco | 25 |
| 46 | 25MW Li-Ion Battery_nnm | Li-Ion_Battery | Owned | nnm | 25 |
| 47 | 25MW Li-Ion Battery_wco | Li-Ion_Battery | Owned | wco | 25 |
| 48 | 25MW Li-Ion Battery_wyo | Li-Ion_Battery | Owned | wyo | 25 |
| 49 | 50MW 8Hr Li-Ion Battery_eco | Li-Ion_Battery | Owned | eco | 50 |
| 50 | 50MW 8Hr Li-Ion Battery_nnm | Li-Ion_Battery | Owned | nnm | 50 |
| 51 | 50MW 8Hr Li-Ion Battery_swco | Li-Ion_Battery | Owned | swco | 50 |
| 52 | Pumped Storage - nnm | Hydro | Owned | nnm | 300 |
| 53 | CP-1x130PV-eco | Solar_PV | PPA | eco | 130 |
| 54 | CP-1x165Wind-eco | Wind | PPA | eco | 165 |
| 55 | 270_18x6RICE_eco | Recip_Engine | Owned | eco | 270 |
| 56 | CP-1x230PV-eco | Solar_PV | PPA | eco | 230 |
| 57 | CP-1x280Wind-eco | Wind | PPA | eco | 280 |
| 58 | 500MW Li-Ion Battery_eco | Li-Ion_Battery | Owned | eco | 500 |
| 59 | CP-1x40PV-eco | Solar_PV | PPA | eco | 40 |
| 60 | CP-1x40Wind-eco | Wind | PPA | eco | 40 |
| 61 | 306_18x6RICE_eco | Recip_Engine | Owned | eco | 306 |

## Overall Methodology

Our overall methodology for the Benchmarking was to first select for each Existing Resource a Generic Resource for comparison. We identified certain criteria to guide and constrain the selection of the Generic Resource for comparison (the "Selection Criteria"). The Selection Criteria included 1) that the Generic Resource must be of similar technology to the Existing Resource (e.g. a thermal resource could not be compared with a renewable resource), 2) that the Generic Resource must have a similar location as the Existing Resource, 3) that the Generic Resource must have a capacity similar to the Existing Resource and 4) that the Generic Resource must be capable of operating at or above the annual capacity factor typically expected for a resource of that type. Each combination of Existing Resource and its associated Generic Resource for comparison was known as a "Pairing".

The total capacity of the Existing Resource rather than just the Tri-State Modeled Capacity was considered in selecting the Generic Resource for comparison. This was done because the performance and cost of Tri-State's share of the Existing Resource benefits from the economies of scale of the entire Existing Resource (for example, entire resource heat rate, variable O&M cost rate, fixed O&M cost rate) and therefore a Generic Resource of similar size to the entire Existing Resource should be selected for a fair comparison.

Once the Pairings had been made, we then forecast the annual capacity, energy production and annual operating and ownership costs of both the Existing Resource and the Generic Resource for the years 2021-2040 assuming they would operate in isolation from each other and all other resources. Both the Existing Resource and the Generic resource were forecast to operate at a capacity factor consistent with resources of their types and with historical or expected capacity factors for the Existing Resources as reported by Tri-State (the "Common Capacity Factor"). Energy for each Existing Resource was forecast based on the Common Capacity Factor and its Tri-State Modeled Capacity. Energy for each Generic

Resource was forecast to operate based on the Common Capacity Factor but only a portion of the Plant Capacity equal to their Tri-State Modeled Capacity for the Existing Resource (the "Tri-State Share"). This was done so that the forecast energy production for the Existing Resource and the Generic resource were the same, as if Tri-State was to own just a share of the Generic Resource.

Assumptions for fuel cost, heat rate, carbon emission rates, fixed O&M, variable O&M, capital expenditures, capital basis, depreciation, book life and PPA price (for the third party owned renewable resources) were specific to each Existing Resource and Generic Resource. Assumptions for the Existing Resources were provided by Tri-State but reviewed by us and in some cases modified by Tri-State in consultation with us as part of our Existing Resource Review work. Similarly, assumptions for the Generic Resources were provided by Tri-State but reviewed by us and in some cases modified by Tri-State in consultation with us as part of our Generic Resource Review work. Assumptions for a limited number of the Generic Resources were developed by us. Please see the Results section of this report for a more detailed description of these assumptions and the forecasting methodology. The forecasts were made on an "equal service life" basis ensuring the Existing Resource and Generic Resource were modeled to operate for the same years in the study period. Assumptions provided by Tri-State were aligned with those used in their resource capacity expansion modeling software and were not representative of inputs specific to their financial modeling.

We then discounted the annual capacity, energy production and annual cost streams to net present values and used them to calculate a levelized cost in 2020 dollars for both the Existing Resource and Generic Resource. In cases where the Common Capacity Factor was relatively high, we calculated a levelized cost of energy (LCOE) in $/MWh. In cases where the Common Capacity Factor was relatively low, we calculated a levelized cost of capacity (LCOC) in $/kw-yr. We then compared the LCOE or LCOC results for the Existing Resource and the Generic Resource and commented on why they differed.

## Expanded Methodology for the Basin Contracts

For the Basin Contracts, a special methodology was necessary because no specific generating resource is associated with either Basin Contract. For the purposes of benchmarking this type of unspecified energy with varying profiles, we expanded the methodology to allow comparison of each Basin Contract against a group of three (3) Generic Resources (a "Generic Composite") instead of just a single Generic Resource. Use of three resources of differing types was judged a reasonable proxy for a system resource for the purposes of benchmarking.

Generic Resources were selected for each Generic Composite based on three general criteria; 1) to maximize the use of renewable resources; 2) to match the forecast delivery profile of the associated Basin Contract as best possible and 3) minimize the overall cost of the Generic Composite. We began the selection process by examining the hourly Basin Contract forecast energy profile for a typical year (8760 hours). We then attempted to replicate the Basin Contract profile with the hourly forecast energy profiles of the various sized solar and wind Generic Resources. Invariably, there were hours in which the combined forecast solar and wind profiles were insufficient to replicate the Basin Contract profile. In these cases, we introduced a forecast hourly profile for a dispatchable resource to fill the gap. The dispatchable resource was either Recip_Engine, Aeroderivative_CT, Frame_CT, Frame_CCCT or Li-Ion

Battery based. For a battery resource, it was assumed to store energy from the selected solar and wind resources only with a certain efficiency "round-trip" loss.

Although specific generating resources are not associated with the Basin Contracts, Tri-State did provide us with carbon emission rates based on how the Basin Contracts primarily have been historically served to apply to the Basin Contracts.

# Results

This section includes results of the resource Pairing, a detailed description of the forecasting and costing methodology with detailed results for one of the Pairings, and a summary of the LCOE and LCOC results for all of the Pairings.

## Pairings

Table 3 summarizes results of the resource Pairing.

The coal-fired Existing Resources have plant capacities ranging from 410 to 570 MW with relatively high historical capacity factors reported by Tri-State. Therefore, each of these Existing Resources was paired with the large gas-fired combined cycle combustion turbine (545_1x1_7HA03_nwco) Generic Resource. This Pairing satisfies the Selection Criteria except in the case of the Springerville 3 (SV 3) resource and the Laramie River Station (LRS2, LRS 3) resources. With respect to SV 3, the Generic Resource has a northwest Colorado location instead of an Arizona location. However, we judged the pairing as reasonable since no other CCCT Generic Resource is located in Arizona. With respect to LRS 2 and LRS 3, the Generic Resource has a capacity (545 MW) that is smaller than LRS 2 and LRS 3 (570 MW). However, we judged the Pairings as reasonable because no Frame_CCCT Generic Resource has a capacity greater than LRS. The 545_1x1_7HA03_nwco Generic Resource is the largest Frame_CCCT Generic Resource. We also judged the other coal-fired resource Pairings reasonable even though the capacity (545 MW) is much greater than that of the other coal-fired resources (410-448 MW). This is because no other Frame_CCCT Generic Resource has a capacity greater than 375 MW and therefore would not have satisfied the Selection Criteria. We set the Common Capacity Factor for each Pairing equal to eighty (80) percent which is representative for large coal fired resources and large gas-fired combined cycle resources. This capacity factor is also representative of air quality permit limitations for Craig 1 which limits its capacity factor to 80%.

The combustion turbine Existing Resources have plant capacities ranging from 40 to 70 MW and relatively low historical and expected capacity factors reported by Tri-State. Therefore, each of these resources was paired with a small simple cycle combustion turbine (781_2x40LM6000_eco) Generic Resource. This Pairing satisfied the Selection Criteria. We set the Common Capacity Factor for each Pairing equal to fifteen (15) percent which is representative for combustion turbine resources.

The Rifle Existing Resource is relatively small (81 MW) combined cycle plant. Although a combined cycle plant, Rifle has a historical and expected capacity factor reported by Tri-State that is much lower than typical for combined cycle resource and more typical of a combustion turbine resource. Therefore, the Rifle resource was paired with the same small simple cycle combustion turbine (81_2x40LM6000_eco) Generic Resource used for the combustion turbine Existing Resources. This Pairing satisfied the

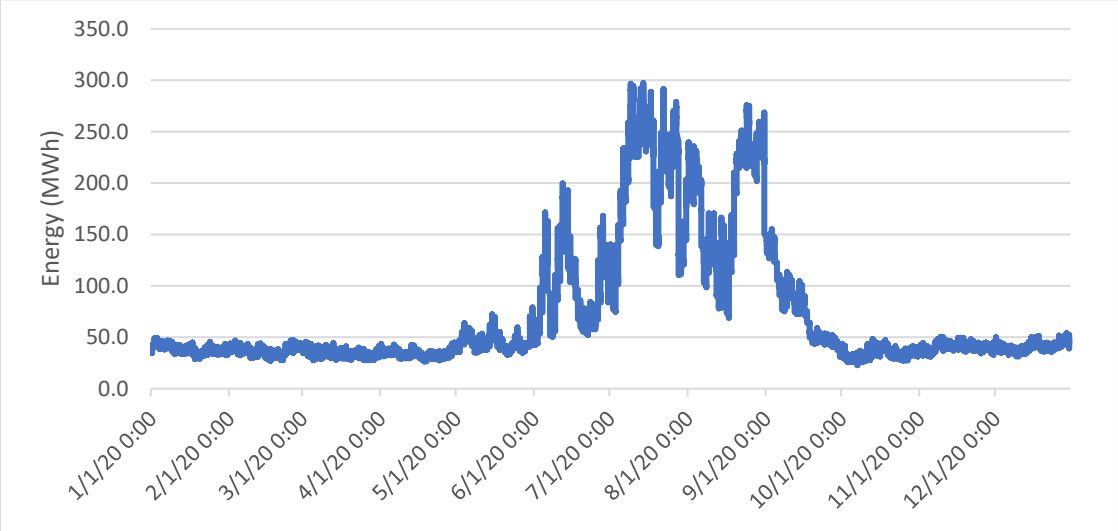
Selection Criteria. We set the Common Capacity Factor for the Pairing equal to fifteen (15) percent which is representative for combustion turbine resources.

The Shafer combined cycle Existing Resource is relatively large (272 MW) with a historical and expected capacity factor reported by Tri-State of approximately thirty five (35) percent. This is relatively low with respect to typical combined cycle resources yet relatively high compared with combustion turbine resources. We decided to pair the Shafer resource with the small gas-fired combined cycle combustion turbine (300_1x1_7FA05_eco) Generic Resource. We felt this was more representative than pairing it with a combustion turbine resource. This Pairing satisfies the Selection Criteria. We set the Common Capacity Factor for the Pairing equal to thirty five (35) percent.

The solar PV Existing Resources were paired with the 100 MW solar PV (CP-1x100PV_eco) Generic Resource. The wind Existing Resources were paired with the 100 MW wind (CP-1x100Wind_eco) Generic Resource. These Pairings satisfy the Selection Criteria, with the exception of the Carousel wind resource. The wind Generic resource has a capacity (100 MW) that is less than the Carousel capacity (150 MW). However, we judged this Pairing reasonable because there is no wind Generic Resource with a capacity greater than 100 MW. We set the Common Capacity Factor for the Pairings equal to the historical capacity factors reported by Tri-State for the Existing Resources.

The Basin West Contract was paired with a Generic Composite consisting of a 230 MW Solar PV resource PPA in eco (CP-1x130PV-eco), a 280 MW Wind resource PPA in eco (CP-1x280Wind-eco) and a 500 MW Li-Ion Battery resource Owned in eco (500MW Li-Ion Battery_eco). The Basin East Contract was paired with a 40 MW Solar PV resource PPA in eco (CP-1x40PV-eco), a 40 MW wind resource PPA in eco (CP-1x40Wind-eco) and a 306 MW RICE resource Owned in eco (306_18x6RICE_eco). It's important to note that a gas-fired dispatchable resource was selected for the Basin East Generic Composite rather than a Li-Ion Battery resource. This was due to the fact that the Basin East Contract energy demand is driven by irrigation loads which are consistently high in the summer and consistently low in the winter (see Figure 1 below). It was judged that a Li-Ion Battery resource with just 4 hours of duration and a relatively high capital cost would have very little utilization over the year and therefore would be less cost-effective than a RICE generating resource with a relatively low capital cost.

*Figure 1 – Hourly Energy Profile for the Basin East Contract*




## Forecasting Methodology and Craig 1 Results

This section provides a detailed description of the methodology used for the forecasting and LCOE and LCOC calculations for Benchmarking of Existing Resources other than the Basin Contracts. As a guide, detailed results for the Craig 1 Pairing are shown below (Table 4 for the Existing Resource and Table 5 for the Generic Resource). Assumptions and results are shown in the upper left portion of the results with the annual cost forecast shown below that. A summary of LCOE and LCOC results for all the Pairings are provided in the subsequent LCOE and LCOC Results section.

Generation for the Existing Resource was forecast to be constant every year based on the Tri-State Modeled Capacity and the Common Capacity Factor for the Existing Resource, and the Tri-State Share and the Common Capacity Factor for the Generic Resource.

For Existing Resources and Generic Resources to be owned by Tri-State, fuel cost was forecast based on the heat rate multiplied by the generation and the first year fuel price (Fuel Cost 2021). For costs in subsequent years the fuel price was escalated at the fuel cost escalation rate which was set equal to the compound annual growth rate of prices observed in the fuel price forecasts provided by Tri-State. Carbon costs were forecast similarly, based on the generation, the carbon emission rate of the resource and the first year Social Cost of Carbon (Social Cost of Carbon 2021) and an escalation rate based on the compound annual growth rate of the Social Cost of Carbon forecast provided by Tri-State. Variable O&M (VOM) was forecast based on generation and the first year variable O&M cost (VOM Cost 2021) and an assumed VOM cost escalation rate. Fuel, carbon and VOM forecasts were not applicable to the resources to be owned by third parties.

For Existing Resources and Generic Resources to be owned by Tri-State, fixed operations and maintenance cost (FOM) and capital expenditures (Capex) were forecast similarly to VOM except in the case of the Existing Resources for which resource-specific forecasts were provided by Tri-State. In order

to ensure equal service lives between the Existing Resource and the Generic Resource, we requested for the purposes of the Benchmarking that Tri-State develop the Existing Resource forecasts assuming that the Existing Resources would operate for the entire study period (through 2040). This ran counter to planned retirement decisions for the Existing Resources, in particular the Craig 1 resource which will be retired by 2025 and Craig 2 and Craig 3 resources which will be retired by 2030, but was necessary to the integrity of the comparison. In addition, Tri-State indicated they would not be expending capex in the final five years of the resource life for the Existing Resources and the Generic Resources. Therefore, the capex costs for the years 2035 through 2040 were assumed to be zero for both the Existing Resources and the Generic Resources. FOM and Capex forecasts were not applicable to the resources to be owned by third parties.

For Existing Resources and Generic Resources to be owned by Tri-State, interest and depreciation were forecast based on the undepreciated capital cost of the resource at the beginning of each year (Capex Balance) multiplied by an assumed debt interest rate and an assumed depreciation rate. The resulting interest and depreciation were deducted from the subsequent year Capex Balance. For the Existing Resources the assumed interest and depreciation rates were provided by Tri-State. For the Generic Resources we assumed the same debt interest rate but a depreciation rate equal to straight line depreciation over a 30 year life. Interest and depreciation forecasts were not applicable to the resources to be owned by third parties.

For Existing Resources and Generic Resources to be owned by Tri-State, we also forecast the liability that Tri-State would incur at the time an Existing Resource owned by Tri-State would reach the end of its depreciation life (the "Accounting Retirement Year"). This liability would occur if and to the extent that the resource is not fully depreciated at the end of the Accounting Retirement Year. We characterized this liability as the "Stranded Cost" of the resource which we set equal to the beginning Capex Balance plus the Capex amount in the year equal to the Accounting Year. The Accounting Year assumption was provided by Tri-State.

For Existing Resources and Generic Resources that are (or would be) owned by third parties, PPA Cost was forecast based on Generation multiplied by a PPA price forecast. For Existing Resources, the PPA price forecast was provided by Tri-State. For Generic Resources, the PPA price forecast was developed by us as part of our Generic Resource Review work.

For calculation of LCOE and LCOC, we first calculated the net present value (NPV) of total costs (Total), fixed costs (Fixed Only), Generation and Capacity by discounting the annual cost values to the year 2020 using a discount rate equal to the debt interest rate. The debt interest rate represents the weighted average cost of capital of Tri-State since Tri-State does not have equity in its capital structure. LCOE was then calculated as the ratio of Total NPV to Generation NPV expressed as $/MWh. LCOC was calculated as the ratio of Fixed Only NPV to Capacity NPV expressed as $/kw-year.

## LCOE and LCOC Results

A summary of LCOE and LCOC results for all the Pairings is shown in Table 6. Results broken down by cost component are shown on Figure 2, Figure 3 and Figure 4.

For the coal-fired plant pairings, only LCOE results are relevant. Results show that the Existing Resources are more costly than the Generic Resources due primarily to higher Social Cost of Carbon and higher FOM costs. The difference is greatest for Springerville 3 due to its relatively high interest cost in addition to the Social Cost of carbon and FOM cost differences.

For the Frame CT pairings, only LCOC results are relevant. Results show that the Existing Resources are less costly than the Generic Resources due to lower depreciation, interest, capex and FOM costs. The Existing Resources benefit from very low (highly depreciated) Capex Balance and therefore lower interest and depreciation costs.

For the Shafer Pairing, both the LCOE and LCOC results are relevant. The Common Capacity Factor of 35% is relatively low for a resource that is intended to provide energy (such as a CCCT) and relatively high for a resource that is intended to provide capacity (such as a CT). LCOE results show that Shafer is less costly than the Generic Resource due primarily to very low (highly depreciated) Capex Balance and therefore lower interest and depreciation costs. LCOC results also show Shafer less costly, with the difference due to the same reasons.

For the renewable plant Pairings, only LCOE results are relevant. Results show that the Existing Resources are more costly than the Generic Resources for nearly all the Pairings. This is likely because the Existing Resources were built in prior years when the cost of solar and wind technology was high relative to the costs expected in future years (a declining capital cost curve). The exception is the Twin Buttes wind resource. Its LCOE is less than the Generic Resource. Review of the Twin Buttes PPA price forecast reveals that it has a low price with no escalation which compares favorably to the Generic resource that has a similar first year price but is assumed to escalate at 2% annually thereafter.

For the Basin Contracts, only LCOE results are relevant. Results show that the Basin West Contract is more costly than its Generic Composite. This is primarily because the Basin West Contract has a carbon emission rate and therefore incurs a Social Cost of Carbon whereas the Generic Composite does not (all renewables and battery storage). The impact of the Social Cost of Carbon becomes evident when examining the case where there is no Social Cost of Carbon as described in the Non-Colorado Benchmarking section below. Conversely to the Basin West results, the Basin East Contract results show that the Basin East Contract is less costly than its Generic Composite. The Basin East Contract incurs a Social Cost of Carbon, but so does its Generic Composite along with the relatively high cost of installing and operating a new RICE resource. The net effect is a higher cost for the Generic Composite.

## Non-Colorado Benchmarking

In addition to the Benchmarking described above, we also performed a supplemental analysis concerning only the Existing Resources not located in Colorado (“Non-Colorado Resources”) to examine how their LCOE and LCOC would change if the Social Cost of Carbon was not applied (“Non-Colorado Benchmarking”). The overall methodology, pairing and forecast methodology was identical to the Benchmarking, except that the Social Cost of Carbon was set to zero for both the Existing Resources and the Generic Resources.

A summary of LCOE and LCOC results for the Non-Colorado Benchmarking is shown in Table 7 below.

LCOE results show that both the Non-Colorado Existing Resources and the Non-Colorado Generic Resources are significantly less costly than under the Benchmarking above. For the thermal resources, although the Existing Resources are still more costly than the Generic Resources the gap in cost is narrowed significantly. This is particularly true for LRS Units 2 and 3 where the cost difference is narrowed to approximately ten (10) percent. LCOE results for the renewable resources are unchanged from the Benchmarking results above since the Social Cost of Carbon does not apply to renewable resources. LCOE results for the Basin Contracts show that each contract is less expensive than its Generic Composite if the Social Cost of Carbon is not applied.

LCOC results are identical to those under the Benchmarking above. This is because the Social Cost of Carbon is a variable cost and therefore is not a component of LCOC which considers fixed costs only.

*Table 3 – Results of the Pairings of Existing Resources with Generic Resources for Comparison*

| | Pairings | | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | Existing Resource | | | | Generic Resource 1 | | | | Generic Resource 2 | | | | Generic Resource 3 | | | |
| | Name | Type | Plant Capacity (MW) | Tri-State Modeled Capacity (MW) | Name | Type | Capacity | Capacity Factor for Comparison | Name | Type | Capacity | Capacity Factor for Comparison | Name | Type | Capacity | Capacity Factor for Comparison |
| 1 | GC-Craig 1-NW_CO | Steam Turbine - Coal | 427 | 102 | 545_1x1_7HA03_nwco | Frame_CCCT | 545 | 80% | n/a | n/a | n/a | n/a | n/a | n/a | n/a | n/a |
| 2 | GC-Craig 2-NW_CO | Steam Turbine - Coal | 410 | 98 | 545_1x1_7HA03_nwco | Frame_CCCT | 545 | 80% | n/a | n/a | n/a | n/a | n/a | n/a | n/a | n/a |
| 3 | GC-Craig 3-NW_CO | Steam Turbine - Coal | 448 | 448 | 545_1x1_7HA03_nwco | Frame_CCCT | 545 | 80% | n/a | n/a | n/a | n/a | n/a | n/a | n/a | n/a |
| 4 | GC-LRS 2-WY | Steam Turbine - Coal | 570 | 231 | 545_1x1_7HA03_nwco | Frame_CCCT | 545 | 80% | n/a | n/a | n/a | n/a | n/a | n/a | n/a | n/a |
| 5 | GC-LRS 3-WY | Steam Turbine - Coal | 570 | 230 | 545_1x1_7HA03_nwco | Frame_CCCT | 545 | 80% | n/a | n/a | n/a | n/a | n/a | n/a | n/a | n/a |
| 6 | GC-SV 3-SPV | Steam Turbine - Coal | 417 | 317 | 545_1x1_7HA03_nwco | Frame_CCCT | 545 | 80% | n/a | n/a | n/a | n/a | n/a | n/a | n/a | n/a |
| 7 | GG-Burlington 1-E_CO | Frame CT - Oil | 55 | 55 | 81_2x40LM6000_eco | Aeroderivative_CT | 81 | 15% | n/a | n/a | n/a | n/a | n/a | n/a | n/a | n/a |
| 8 | GG-Burlington 2-E_CO | Frame CT - Oil | 55 | 55 | 81_2x40LM6000_eco | Aeroderivative_CT | 81 | 15% | n/a | n/a | n/a | n/a | n/a | n/a | n/a | n/a |
| 9 | GG-Knutson 1-E_CO | Frame CT - Gas | 70 | 70 | 81_2x40LM6000_eco | Aeroderivative_CT | 81 | 15% | n/a | n/a | n/a | n/a | n/a | n/a | n/a | n/a |
| 10 | GG-Knutson 2-E_CO | Frame CT - Gas | 70 | 70 | 81_2x40LM6000_eco | Aeroderivative_CT | 81 | 15% | n/a | n/a | n/a | n/a | n/a | n/a | n/a | n/a |
| 11 | GG-Limon 1-E_CO | Frame CT - Gas | 70 | 70 | 81_2x40LM6000_eco | Aeroderivative_CT | 81 | 15% | n/a | n/a | n/a | n/a | n/a | n/a | n/a | n/a |
| 12 | GG-Limon 2-E_CO | Frame CT - Gas | 70 | 70 | 81_2x40LM6000_eco | Aeroderivative_CT | 81 | 15% | n/a | n/a | n/a | n/a | n/a | n/a | n/a | n/a |
| 13 | GG-Pyramid 1-S_NM | Aeroderivative CT - Gas | 40 | 40 | 40_1x40LM6000_nnm | Aeroderivative_CT | 40 | 15% | n/a | n/a | n/a | n/a | n/a | n/a | n/a | n/a |
| 14 | GG-Pyramid 2-S_NM | Aeroderivative CT - Gas | 40 | 40 | 40_1x40LM6000_nnm | Aeroderivative_CT | 40 | 15% | n/a | n/a | n/a | n/a | n/a | n/a | n/a | n/a |
| 15 | GG-Pyramid 3-S_NM | Aeroderivative CT - Gas | 40 | 40 | 40_1x40LM6000_nnm | Aeroderivative_CT | 40 | 15% | n/a | n/a | n/a | n/a | n/a | n/a | n/a | n/a |
| 16 | GG-Pyramid 4-S_NM | Aeroderivative CT - Gas | 40 | 40 | 40_1x40LM6000_nnm | Aeroderivative_CT | 40 | 15% | n/a | n/a | n/a | n/a | n/a | n/a | n/a | n/a |
| 17 | GG-Rifle-NW_CO | Combined Cycle - Gas | 81 | 81 | 81_2x40LM6000_eco | Aeroderivative_CT | 81 | 15% | n/a | n/a | n/a | n/a | n/a | n/a | n/a | n/a |
| 18 | GG-Shafer-E_CO | Combined Cycle - Gas | 272 | 272 | 300_1x1_7FA05_eco | Frame_CCCT | 300 | 35% | n/a | n/a | n/a | n/a | n/a | n/a | n/a | n/a |
| 19 | CP-AltaLuna-S_NM | Tracking Array Solar | 25 | 25 | CP-1x100PV_nnm | Solar_PV | 100 | 35% | n/a | n/a | n/a | n/a | n/a | n/a | n/a | n/a |
| 20 | CP-SanIsabel-E_CO | Tracking Array Solar | 30 | 30 | CP-1x100PV_eco | Solar_PV | 100 | 29% | n/a | n/a | n/a | n/a | n/a | n/a | n/a | n/a |
| 21 | CP-FirstSolar-N_NM | Fixed Solar | 30 | 30 | CP-1x100PV_nnm | Solar_PV | 100 | 22% | n/a | n/a | n/a | n/a | n/a | n/a | n/a | n/a |
| 22 | CP-ColoHighlands-E_CO | Wind | 91 | 91 | CP-1x100Wind_eco | Wind | 100 | 46% | n/a | n/a | n/a | n/a | n/a | n/a | n/a | n/a |
| 23 | CP-KitCarson-E_CO | Wind | 51 | 51 | CP-1x100Wind_eco | Wind | 100 | 42% | n/a | n/a | n/a | n/a | n/a | n/a | n/a | n/a |
| 24 | CP-TwinButtes-E_CO | Wind | 76 | 76 | CP-1x100Wind_eco | Wind | 100 | 45% | n/a | n/a | n/a | n/a | n/a | n/a | n/a | n/a |
| 25 | CP-Carousel-E_CO | Wind | 150 | 150 | CP-1x100Wind_eco | Wind | 100 | 51% | n/a | n/a | n/a | n/a | n/a | n/a | n/a | n/a |
| 26 | CP-Basin_West | Basin System | 268 | 268 | CP-1x230PV-eco | Solar_PV | 230 | 30% | CP-1x280Wind-eco | Wind | 280 | 43% | 500MW Li-Ion Battery_eco | Li-Ion_Battery | 500 | 9% |
| 27 | CP-Basin_East | Basin System | 317 | 317 | CP-1x40PV-eco | Solar_PV | 40 | 30% | CP-1x40Wind-eco | Wind | 40 | 43% | 306_18x6RICE_eco | Recip_Engine | 306 | 16% |

*Table 4 LCOE and LCOC Calculations for an Existing Resource*

| **LCOE and LCOC (values in 2020 $ million unless stated otherwise)** | | | | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Existing Resource | GC-Craig 1-NW_CO | | | | | Calculate LCOE and | | | | | | | | | | | |
| Technology | Steam Turbine - Coal | | | | | | | | | | | | | | | | |
| Type | Owned | | | | | | | | | | | | | | | | |
| Basin Contract? | No | | | | | | | | | | | | | | | | |
| Assumptions | Base | Escalation | | | | | | | | | | | | | | | |
| Plant Capacity (MW) | 427 | | | | | | | | | | | | | | | | |
| Tri-State Share (MW) | 102 | | | | | | | | | | | | | | | | |
| Capacity Factor | 80% | | | | | | | | | | | | | | | | |
| Heat Rate (Btu/kwh) | 10,316 | | | | | | | | | | | | | | | | |
| Fuel Cost 2021 ($/MMBtu) | [redacted] | 0.2% | | | | | | | | | | | | | | | |
| VOM Cost 2021 ($/MWh) | | 0.0% | | | | | | | | | | | | | | | |
| Social Cost of Carbon 2021 ($/MWh) | $46.00 | 1.8% | | | | | | | | | | | | | | | |
| FOM Cost 2021 ($/kw-yr) | See Detail | 0.0% | | | | | | | | | | | | | | | |
| Capex Cost 2021 Tri-State Share ($ million/yr) | $0.8 | 3.0% | | | | | | | | | | | | | | | |
| Capex Balance 2021 BOY ($ million) | $86 | | | | | | | | | | | | | | | | |
| Debt Interest Rate | 2.21% | | | | | | | | | | | | | | | | |
| Debt Term (Years) | 30 | | | | | | | | | | | | | | | | |
| Depreciation Rate | 4% | | | | | | | | | | | | | | | | |
| Accounting Retirement Year | 2025 | | | | | | | | | | | | | | | | |
| PPA First Year Energy Price ($/MWh) | n/a | n/a | | | | | | | | | | | | | | | |
| PPA First Year Capacity Price ($/kw-mo) | n/a | n/a | | | | | | | | | | | | | | | |
| PPA Start Year | n/a | | | | | | | | | | | | | | | | |
| PPA Term | n/a | | | | | | | | | | | | | | | | |
| Discount Rate | 2.21% | | | | | | | | | | | | | | | | |
| Results | | | | | | | | | | | | | | | | | |
| **Levelized Cost of Energy (2020 $/MWh)** | **$101** | | | | | | | | | | | | | | | | |
| **Levelized Cost of Capacity (2020 $/kw-yr)** | **$154** | | | | | | | | | | | | | | | | |
| Detail | | | | | | | Book | | | | | | | | | | |
| | Generation (GWh) | Fuel | VOM | Social Cost of Carbon | FOM | Capex Balance | Capex | Interest | Depreciation | Stranded Cost | PPA Cost | Total | Total ($/MWh) | Capacity (MW) | Fixed Only | Total Fixed Only ($/kw-yr) | |
| NPV | 11,455 | [redacted] | | | [redacted] | | | | | | | $1,160.4 | | 1,635 | [redacted] | | |
| 2021 | 715 | | | $38.1 | | $86.3 | $0.8 | $1.9 | $3.7 | $0.0 | $0.0 | $65.7 | $92 | 102 | | | |
| 2022 | 715 | | | $38.8 | | $83.5 | $1.0 | $1.9 | $3.6 | $0.0 | $0.0 | $66.4 | $93 | 102 | | | |
| 2023 | 715 | | | $39.5 | | $80.9 | $1.1 | $1.8 | $3.5 | $0.0 | $0.0 | $67.1 | $94 | 102 | | | |
| 2024 | 715 | | | $40.2 | | $78.6 | $1.4 | $1.8 | $3.4 | $0.0 | $0.0 | $67.9 | $95 | 102 | | | |
| 2025 | 715 | | | $40.9 | | $76.6 | $1.6 | $1.7 | $3.3 | $78.2 | $0.0 | $147.0 | $206 | 102 | | | |
| 2026 | 715 | | | $41.7 | | $74.9 | $2.5 | $0.0 | $0.0 | $0.0 | $0.0 | $63.6 | $89 | 102 | | | |
| 2027 | 715 | | | $42.4 | | $77.4 | $2.8 | $0.0 | $0.0 | $0.0 | $0.0 | $64.6 | $90 | 102 | | | |
| 2028 | 715 | | | $43.2 | | $80.2 | $3.0 | $0.0 | $0.0 | $0.0 | $0.0 | $65.6 | $92 | 102 | | | |
| 2029 | 715 | | | $44.0 | | $83.2 | $3.3 | $0.0 | $0.0 | $0.0 | $0.0 | $66.6 | $93 | 102 | | | |
| 2030 | 715 | | | $44.8 | | $86.5 | $2.9 | $0.0 | $0.0 | $0.0 | $0.0 | $67.1 | $94 | 102 | | | |
| 2031 | 715 | | | $45.6 | | $89.3 | $3.0 | $0.0 | $0.0 | $0.0 | $0.0 | $68.0 | $95 | 102 | | | |
| 2032 | 715 | | | $46.4 | | $92.3 | $3.1 | $0.0 | $0.0 | $0.0 | $0.0 | $68.9 | $96 | 102 | | | |
| 2033 | 715 | | | $47.2 | | $95.4 | $3.1 | $0.0 | $0.0 | $0.0 | $0.0 | $69.9 | $98 | 102 | | | |
| 2034 | 715 | | | $48.1 | | $98.5 | $3.2 | $0.0 | $0.0 | $0.0 | $0.0 | $70.8 | $99 | 102 | | | |
| 2035 | 715 | | | $48.9 | | $101.7 | $0.0 | $0.0 | $0.0 | $0.0 | $0.0 | $68.5 | $96 | 102 | | | |
| 2036 | 715 | | | $49.8 | | $101.7 | $0.0 | $0.0 | $0.0 | $0.0 | $0.0 | $69.4 | $97 | 102 | | | |
| 2037 | 715 | | | $50.7 | | $101.7 | $0.0 | $0.0 | $0.0 | $0.0 | $0.0 | $70.3 | $98 | 102 | | | |
| 2038 | 715 | | | $51.6 | | $101.7 | $0.0 | $0.0 | $0.0 | $0.0 | $0.0 | $71.2 | $100 | 102 | | | |
| 2039 | 715 | | | $52.6 | | $101.7 | $0.0 | $0.0 | $0.0 | $0.0 | $0.0 | $72.2 | $101 | 102 | | | |
| 2040 | 715 | | | $53.5 | | $101.7 | $0.0 | $0.0 | $0.0 | $0.0 | $0.0 | $73.2 | $102 | 102 | | | |

*Table 5 – LCOE and LCOC Calculations for a Generic Resource*

| **LCOE and LCOC (values in 2020 $ million unless stated otherwise)** | | | | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Generic Resource | 1 | | | | | | | | | | | | | | | | |
| Resource | 545_1x1_7HA03_nwco | | | | | | | | | | | | | | | | |
| Technology | Frame_CCCT | | | | | | | | | | | | | | | | |
| Type | Owned | | | | | | | | | | | | | | | | |
| Assumptions | Base | Escalation | | | | | | | | | | | | | | | |
| Plant Capacity (MW) | 545 | | | | | | | | | | | | | | | | |
| Tri-State Share (MW) | 102 | | | | | | | | | | | | | | | | |
| Capacity Factor | 80% | | | | | | | | | | | | | | | | |
| Heat Rate (Btu/kwh) | 6,170 | | | | | | | | | | | | | | | | |
| Fuel Cost 2021 ($/MMBtu) | $1.79 | 4.5% | | | | | | | | | | | | | | | |
| VOM Cost 2021 ($/MWh) | $3.67 | 0.0% | | | | | | | | | | | | | | | |
| Social Cost of Carbon 2021 ($/MWh) | $46.00 | 1.8% | | | | | | | | | | | | | | | |
| FOM Cost 2021 ($/kw-yr) | $10.83 | 0.0% | | | | | | | | | | | | | | | |
| Capex Cost 2021 Tri-State Share ($ million/yr) | $0.5 | 3.0% | | | | | | | | | | | | | | | |
| Installed Cost Tri-State Share ($ million) | $121 | | | | | | | | | | | | | | | | |
| Debt Interest Rate | 2.21% | | | | | | | | | | | | | | | | |
| Debt Term (Years) | 30 | | | | | | | | | | | | | | | | |
| Depreciation Rate | 3% | | | | | | | | | | | | | | | | |
| Accounting Retirement Year | 2051 | | | | | | | | | | | | | | | | |
| PPA First Year Price ($/MWh) | #N/A | n/a | | | | | | | | | | | | | | | |
| PPA Start Year | n/a | | | | | | | | | | | | | | | | |
| PPA Term | n/a | | | | | | | | | | | | | | | | |
| Discount Rate | 2.21% | | | | | | | | | | | | | | | | |
| Results | | | | | | | | | | | | | | | | | |
| **Levelized Cost of Energy (2020 $/MWh)** | **$52** | | | | | | | | | | | | | | | | |
| **Levelized Cost of Capacity (2020 $/kw-yr)** | **$67** | | | | | | | | | | | | | | | | |
| | | | | | | | | | | | | | | | | | |
| Detail | | | | | | | Book | | | | | | | | | | |
| | Generation (GWh) | Fuel | VOM | Social Cost of Carbon | FOM | Capex Balance | Capex | Interest | Depreciation | Stranded Cost | PPA Cost | Total | Total ($/MWh) | Capacity (MW) | Fixed Only | Total Fixed Only ($/kw-yr) | |
| NPV | 11,455 | | | | | | | | | | | $590.7 | | 1,635 | $109.0 | | |
| 2021 | 715 | $7.9 | $2.6 | $13.1 | $1.1 | $121.1 | $0.5 | $2.7 | $4.1 | $0.0 | $0.0 | $31.9 | $45 | 102 | $8.3 | $81 | |
| 2022 | 715 | $8.2 | $2.6 | $13.4 | $1.1 | $117.5 | $0.5 | $2.6 | $3.9 | $0.0 | $0.0 | $32.3 | $45 | 102 | $8.1 | $79 | |
| 2023 | 715 | $8.6 | $2.6 | $13.6 | $1.1 | $114.1 | $0.5 | $2.5 | $3.8 | $0.0 | $0.0 | $32.8 | $46 | 102 | $7.9 | $78 | |
| 2024 | 715 | $9.0 | $2.6 | $13.9 | $1.1 | $110.7 | $0.5 | $2.5 | $3.7 | $0.0 | $0.0 | $33.2 | $47 | 102 | $7.8 | $76 | |
| 2025 | 715 | $9.4 | $2.6 | $14.1 | $1.1 | $107.5 | $0.5 | $2.4 | $3.6 | $0.0 | $0.0 | $33.7 | $47 | 102 | $7.6 | $75 | |
| 2026 | 715 | $9.8 | $2.6 | $14.4 | $1.1 | $104.4 | $0.5 | $2.3 | $3.5 | $0.0 | $0.0 | $34.3 | $48 | 102 | $7.4 | $73 | |
| 2027 | 715 | $10.3 | $2.6 | $14.6 | $1.1 | $101.5 | $0.5 | $2.2 | $3.4 | $0.0 | $0.0 | $34.8 | $49 | 102 | $7.3 | $72 | |
| 2028 | 715 | $10.7 | $2.6 | $14.9 | $1.1 | $98.6 | $0.6 | $2.2 | $3.3 | $0.0 | $0.0 | $35.4 | $50 | 102 | $7.2 | $70 | |
| 2029 | 715 | $11.2 | $2.6 | $15.2 | $1.1 | $95.8 | $0.6 | $2.1 | $3.2 | $0.0 | $0.0 | $36.0 | $50 | 102 | $7.0 | $69 | |
| 2030 | 715 | $11.7 | $2.6 | $15.4 | $1.1 | $93.2 | $0.6 | $2.1 | $3.1 | $0.0 | $0.0 | $36.7 | $51 | 102 | $6.9 | $68 | |
| 2031 | 715 | $12.2 | $2.6 | $15.7 | $1.1 | $90.7 | $0.6 | $2.0 | $3.0 | $0.0 | $0.0 | $37.3 | $52 | 102 | $6.8 | $66 | |
| 2032 | 715 | $12.8 | $2.6 | $16.0 | $1.1 | $88.2 | $0.6 | $2.0 | $3.0 | $0.0 | $0.0 | $38.1 | $53 | 102 | $6.7 | $65 | |
| 2033 | 715 | $13.4 | $2.6 | $16.3 | $1.1 | $85.9 | $0.6 | $1.9 | $2.9 | $0.0 | $0.0 | $38.8 | $54 | 102 | $6.5 | $64 | |
| 2034 | 715 | $14.0 | $2.6 | $16.6 | $1.1 | $83.7 | $0.7 | $1.9 | $2.8 | $0.0 | $0.0 | $39.6 | $55 | 102 | $6.4 | $63 | |
| 2035 | 715 | $14.6 | $2.6 | $16.9 | $1.1 | $81.5 | $0.0 | $1.8 | $2.7 | $0.0 | $0.0 | $39.7 | $56 | 102 | $5.6 | $55 | |
| 2036 | 715 | $15.3 | $2.6 | $17.2 | $1.1 | $78.8 | $0.0 | $1.7 | $2.6 | $0.0 | $0.0 | $40.5 | $57 | 102 | $5.5 | $54 | |
| 2037 | 715 | $16.0 | $2.6 | $17.5 | $1.1 | $76.2 | $0.0 | $1.7 | $2.5 | $0.0 | $0.0 | $41.4 | $58 | 102 | $5.3 | $52 | |
| 2038 | 715 | $16.7 | $2.6 | $17.8 | $1.1 | $73.6 | $0.0 | $1.6 | $2.5 | $0.0 | $0.0 | $42.3 | $59 | 102 | $5.2 | $51 | |
| 2039 | 715 | $17.4 | $2.6 | $18.1 | $1.1 | $71.2 | $0.0 | $1.6 | $2.4 | $0.0 | $0.0 | $43.2 | $60 | 102 | $5.0 | $49 | |
| 2040 | 715 | $18.2 | $2.6 | $18.4 | $1.1 | $68.8 | $0.0 | $1.5 | $2.3 | $0.0 | $0.0 | $44.2 | $62 | 102 | $4.9 | $48 | |

*Table 6 – Summary of LCOE and LCOC Results*

| | Pairings | | | | Results | | | |
|---|---|---|---|---|---|---|---|---|
| | Existing Resource | Generic Resource 1 | Generic Resource 2 | Generic Resource 3 | LCOE (2020 $/MWh) | | LCOC (2020 $/kw-yr) | |
| | Name | Name | Name | Name | Existing | Generic | Existing | Generic |
| 1 | GC-Craig 1-NW_CO | 545_1x1_7HA03_nwco | n/a | n/a | $101 | $52 | | |
| 2 | GC-Craig 2-NW_CO | 545_1x1_7HA03_nwco | n/a | n/a | $109 | $52 | | |
| 3 | GC-Craig 3-NW_CO | 545_1x1_7HA03_nwco | n/a | n/a | $93 | $55 | | |
| 4 | GC-LRS 2-WY | 545_1x1_7HA03_nwco | n/a | n/a | $92 | $53 | | |
| 5 | GC-LRS 3-WY | 545_1x1_7HA03_nwco | n/a | n/a | $98 | $53 | | |
| 6 | GC-SV 3-SPV | 545_1x1_7HA03_nwco | n/a | n/a | $123 | $53 | | |
| 7 | GG-Burlington 1-E_CO | 81_2x40LM6000_eco | n/a | n/a | | | $48 | $149 |
| 8 | GG-Burlington 2-E_CO | 81_2x40LM6000_eco | n/a | n/a | | | $48 | $149 |
| 9 | GG-Knutson 1-E_CO | 81_2x40LM6000_eco | n/a | n/a | | | $42 | $159 |
| 10 | GG-Knutson 2-E_CO | 81_2x40LM6000_eco | n/a | n/a | | | $42 | $159 |
| 11 | GG-Limon 1-E_CO | 81_2x40LM6000_eco | n/a | n/a | | | $54 | $159 |
| 12 | GG-Limon 2-E_CO | 81_2x40LM6000_eco | n/a | n/a | | | $54 | $159 |
| 13 | GG-Pyramid 1-S_NM | 40_1x40LM6000_nnm | n/a | n/a | | | $43 | $158 |
| 14 | GG-Pyramid 2-S_NM | 40_1x40LM6000_nnm | n/a | n/a | | | $43 | $158 |
| 15 | GG-Pyramid 3-S_NM | 40_1x40LM6000_nnm | n/a | n/a | | | $43 | $158 |
| 16 | GG-Pyramid 4-S_NM | 40_1x40LM6000_nnm | n/a | n/a | | | $43 | $158 |
| 17 | GG-Rifle-NW_CO | 81_2x40LM6000_eco | n/a | n/a | | | $63 | $167 |
| 18 | GG-Shafer-E_CO | 300_1x1_7FA05_eco | n/a | n/a | [redacted] | $104 | $50 | $158 |
| 19 | CP-AltaLuna-S_NM | CP-1x100PV_nnm | n/a | n/a | | $33 | | |
| 20 | CP-SanIsabel-E_CO | CP-1x100PV_eco | n/a | n/a | | $28 | | |
| 21 | CP-FirstSolar-N_NM | CP-1x100PV_nnm | n/a | n/a | | $33 | | |
| 22 | CP-ColoHighlands-E_CO | CP-1x100Wind_eco | n/a | n/a | | $30 | | |
| 23 | CP-KitCarson-E_CO | CP-1x100Wind_eco | n/a | n/a | | $30 | | |
| 24 | CP-TwinButtes-E_CO | CP-1x100Wind_eco | n/a | n/a | | $30 | | |
| 25 | CP-Carousel-E_CO | CP-1x100Wind_eco | n/a | n/a | | $30 | | |
| 26 | CP-Basin_West | CP-1x230PV-eco | CP-1x280Wind-eco | 500MW Li-Ion Battery_eco | | $39 | | |
| 27 | CP-Basin_East | CP-1x40PV-eco | CP-1x40Wind-eco | 306_18x6RICE_eco | | $112 | | |

*Figure 2 – Comparison of LCOE for Thermal Resource Pairings*



*Figure 3 – Comparison of LCOC for Thermal Resource Pairings*

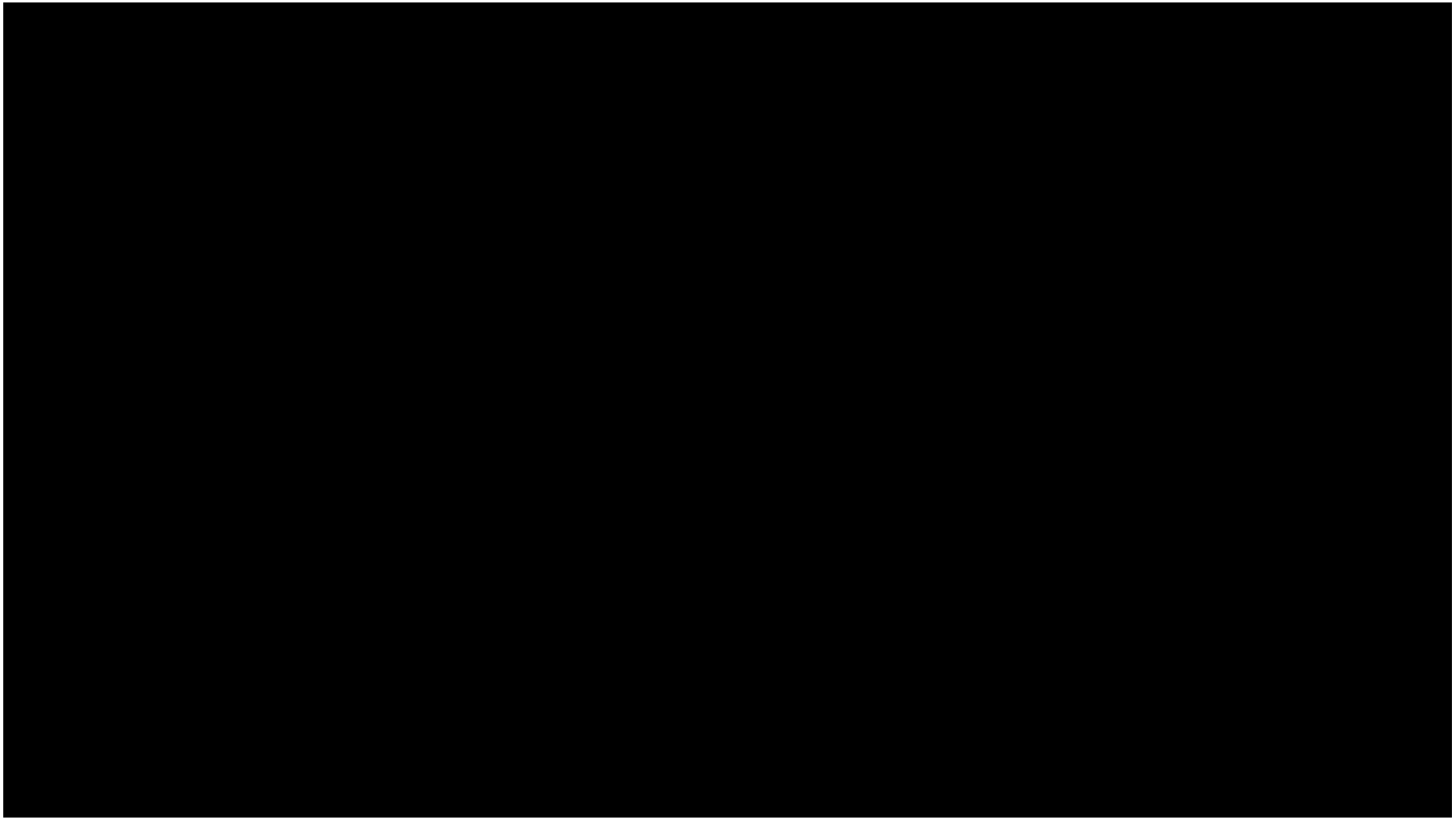


*Figure 4 – LCOE Comparison for the Renewable Resource Pairings*



*Table 7 - Summary of LCOE and LCOC Results for the Non-Colorado Benchmarking*

| | Pairings | | | | Results - Non-Colorado Benchmarking | | | |
|---|---|---|---|---|---|---|---|---|
| | Existing Resource | Generic Resource 1 | Generic Resource 2 | Generic Resource 3 | LCOE (2020 $/MWh) | | LCOC (2020 $/kw-yr) | |
| | Name | Name | Name | Name | Existing | Generic | Existing | Generic |
| 1 | GC-Craig 1-NW_CO | 545_1x1_7HA03_nwco | n/a | n/a | | | | |
| 2 | GC-Craig 2-NW_CO | 545_1x1_7HA03_nwco | n/a | n/a | | | | |
| 3 | GC-Craig 3-NW_CO | 545_1x1_7HA03_nwco | n/a | n/a | | | | |
| 4 | GC-LRS 2-WY | 545_1x1_7HA03_nwco | n/a | n/a | $32 | $31 | | |
| 5 | GC-LRS 3-WY | 545_1x1_7HA03_nwco | n/a | n/a | $33 | $31 | | |
| 6 | GC-SV 3-SPV | 545_1x1_7HA03_nwco | n/a | n/a | $65 | $32 | | |
| 7 | GG-Burlington 1-E_CO | 81_2x40LM6000_eco | n/a | n/a | | | | |
| 8 | GG-Burlington 2-E_CO | 81_2x40LM6000_eco | n/a | n/a | | | | |
| 9 | GG-Knutson 1-E_CO | 81_2x40LM6000_eco | n/a | n/a | | | | |
| 10 | GG-Knutson 2-E_CO | 81_2x40LM6000_eco | n/a | n/a | | | | |
| 11 | GG-Limon 1-E_CO | 81_2x40LM6000_eco | n/a | n/a | | | | |
| 12 | GG-Limon 2-E_CO | 81_2x40LM6000_eco | n/a | n/a | | | | |
| 13 | GG-Pyramid 1-S_NM | 40_1x40LM6000_nnm | n/a | n/a | | | $43 | $158 |
| 14 | GG-Pyramid 2-S_NM | 40_1x40LM6000_nnm | n/a | n/a | | | $43 | $158 |
| 15 | GG-Pyramid 3-S_NM | 40_1x40LM6000_nnm | n/a | n/a | | | $43 | $158 |
| 16 | GG-Pyramid 4-S_NM | 40_1x40LM6000_nnm | n/a | n/a | | | $43 | $158 |
| 17 | GG-Rifle-NW_CO | 81_2x40LM6000_eco | n/a | n/a | | | | |
| 18 | GG-Shafer-E_CO | 300_1x1_7FA05_eco | n/a | n/a | | | | |
| 19 | CP-AltaLuna-S_NM | CP-1x100PV_nnm | n/a | n/a | [redacted] | $33 | | |
| 20 | CP-SanIsabel-E_CO | CP-1x100PV_eco | n/a | n/a | | | | |
| 21 | CP-FirstSolar-N_NM | CP-1x100PV_nnm | n/a | n/a | | $33 | | |
| 22 | CP-ColoHighlands-E_CO | CP-1x100Wind_eco | n/a | n/a | | | | |
| 23 | CP-KitCarson-E_CO | CP-1x100Wind_eco | n/a | n/a | | | | |
| 24 | CP-TwinButtes-E_CO | CP-1x100Wind_eco | n/a | n/a | | | | |
| 25 | CP-Carousel-E_CO | CP-1x100Wind_eco | n/a | n/a | | | | |
| 26 | CP-Basin_West | CP-1x230PV-eco | CP-1x280Wind-eco | 500MW Li-Ion Battery_eco | [redacted] | $39 | | |
| 27 | CP-Basin_East | CP-1x40PV-eco | CP-1x40Wind-eco | 306_18x6RICE_eco | | $91 | | |

**END OF REPORT**

# Appendix C: Mesa Point Energy & BrightLine Group - Tri-State Demand Side Management and Energy Efficiency Potential Study

# DEMAND SIDE MANAGEMENT AND ENERGY EFFICIENCY POTENTIAL STUDY

## FOR TRI-STATE GENERATION & TRANSMISSION

MAY 8, 2020

Prepared by: Mesa Point Energy & BrightLine Group

# TRI-STATE GENERGATION & TRANSMISSION
# DEMAND SIDE MANAGEMENT AND ENERGY EFFICIENCY POTENTIAL STUDY

MAY 8, 2020

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# EXECUTIVE SUMMARY

## Project Overview

Mesa Point Energy, along with their subcontractor Brightline Group, (collectively the Mesa Point Team or the Team) performed a demand side management potential study in support of Tri-State Generation and Transmission's (Tri-State) resources planning initiatives. The study is intended to assist Tri-State in developing their Integrated Resource Plan (IRP) and Electric Resource Plan (ERP). The Mesa Point Team assessed the available technical, economic, and achievable energy and demand savings potential from energy efficiency (EE), demand response (DR), and behind-the-meter distributed energy resources (DER) from 2021 to 2040 for the electric cooperatives served by Tri-State.

The study focuses on energy efficiency, DR, and DER *achievable* potential; it is not a *program* potential study meaning it does not take into consideration program budget and design constraints. Therefore, the study examines what *could be* (i.e., what savings could accrue from considered cost effective measures) but does not account for structural and organizational limitations inherent and unique to the cooperative utility structure where each member can choose which products and measures to offer.

This Executive Summary presents an overview of the analysis approach, key assumptions, and study findings and the main report report goes into more detail on methods, savings, and findings.

A separate electronic reporting tool serves as an appendix to the report. The tool provides the ability to view findings in greater detail by sector, end-use, and region.

## Results by Resource: EE, DR, DER

There are significant opportunities for cost-effective EE and DR savings in the Tri-State service territory. Behind-the-meter DER resources hold significant technical potential but realize limited cost-effective potential based on the analysis framework used for the study.

Given the uncertainty associated with customer adoption of energy-saving technologies, the Mesa Point Team developed achievable scenarios based on four different incentive and program delivery spending levels – from low to maximum levels of program funding.

These scenarios were:

1. Low – assumes incentivizing 25% of incremental cost
2. Moderate – 50% incentive level
3. Aggressive – 75% incentive level
4. Maximum – 100% of incremental cost. Note that maximum funding was assumed to be limited to 100% of the incremental cost to install a measure.

Key findings from each of the three resources assessed, EE, DR, and DER, are summarized below.

## Energy Efficiency (EE) Resource

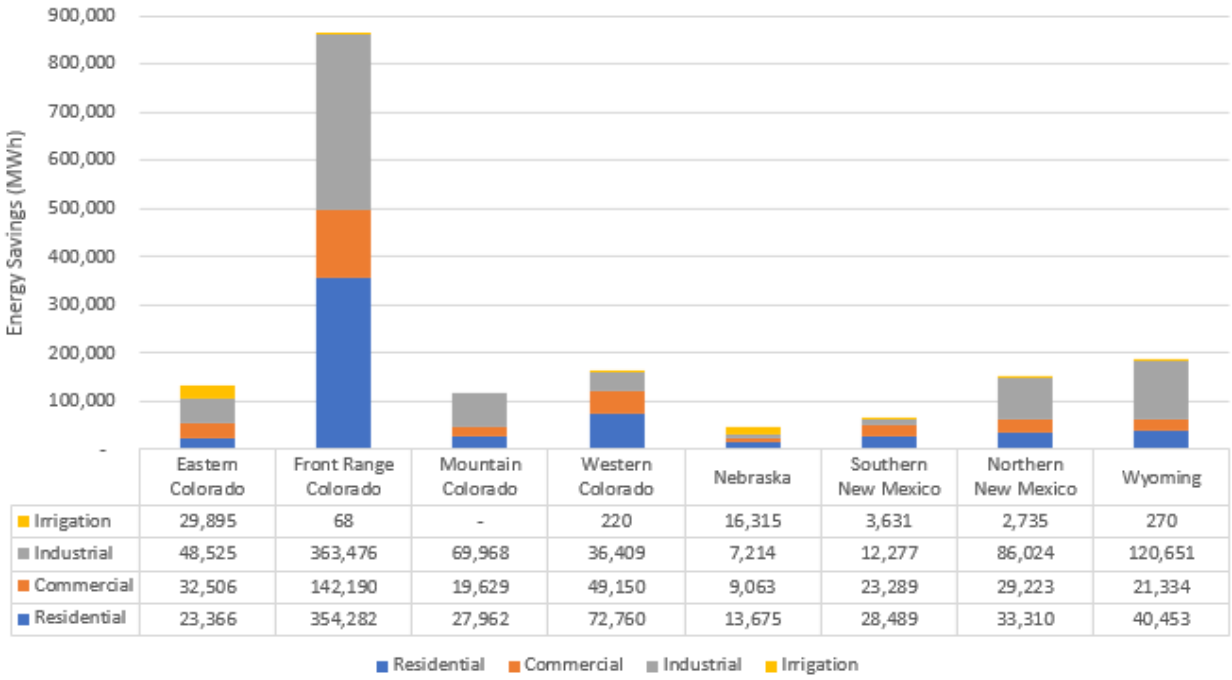
As summarized in Table ES-1, the Mesa Point Team found that the Achievable-moderate scenario would result in approximately 38 GWh (0.25% of sales) of energy efficiency saving in 2021 rising to 1,718 GWh (8.16% of sales) of savings through 2040.

**Table ES-1. Portfolio Cumulative Energy Efficiency Savings by Scenario by Time Horizon**

| MILESTONE YEAR | TECHNICAL | ECONOMIC | ACHIEVABLE _MAX | ACHIEVABLE _ AGG | ACHIEVABLE _MOD | ACHIEVABLE _ LOW |
|---|---|---|---|---|---|---|
| Cumulative Energy Savings (MWh) | | | | | | |
| 2021 (first year) | 130,384 | 98,221 | 75,523 | 55,330 | 38,083 | 27,043 |
| 2025 | 1,293,033 | 928,122 | 539,750 | 393,656 | 266,309 | 179,222 |
| 2030 | 3,868,940 | 2,851,171 | 1,372,971 | 1,062,225 | 723,605 | 475,993 |
| 2040 | 9,081,432 | 6,956,507 | 2,876,487 | 2,354,365 | 1,718,357 | 1,193,109 |
| % of Baseline Sales | | | | | | |
| 2021 (first year) | 0.85% | 0.64% | 0.49% | 0.36% | 0.25% | 0.18% |
| 2025 | 7.88% | 5.65% | 3.29% | 2.40% | 1.62% | 1.09% |
| 2030 | 21.74% | 16.02% | 7.71% | 5.97% | 4.07% | 2.67% |
| 2040 | 43.14% | 33.04% | 13.66% | 11.18% | 8.16% | 5.67% |

Energy effiency savings potential breakdown shares similarities to energy load in terms of distribution by region and by sector (Figure ES-1 and Figure ES-5). Front Range Colorado has the largest cumulative energy savings potential with 860 GWh. Across all regions, the industrial customer sector has more than 744 GWh of cumulative energy savings potential, followed by the residential sector at just under 600 GWh.

**Figure ES-1. 2040 Cumulative Energy Efficiency Savings Potential by Region by Customer Sector (Achievable-Moderate Scenario)**




| | Eastern Colorado | Front Range Colorado | Mountain Colorado | Western Colorado | Nebraska | Southern New Mexico | Northern New Mexico | Wyoming |
|---|---|---|---|---|---|---|---|---|
| Irrigation | 29,895 | 68 | - | 220 | 16,315 | 3,631 | 2,735 | 270 |
| Industrial | 48,525 | 363,476 | 69,968 | 36,409 | 7,214 | 12,277 | 86,024 | 120,651 |
| Commercial | 32,506 | 142,190 | 19,629 | 49,150 | 9,063 | 23,289 | 29,223 | 21,334 |
| Residential | 23,366 | 354,282 | 27,962 | 72,760 | 13,675 | 28,489 | 33,310 | 40,453 |

Table ES-2 summarizes the key cumulative energy efficiency cost metrics across the portfolio at four time horizons under the Achievable-Moderate scenario, as well as 20-year averages across the full study time horizon. It is estimated that over the 20-year study horizon approximately 114 GWh of energy savings is achievable, on average, per year at a cost of $24.3 million for an acquisition cost of $212/MWh. Over the 20 year study horizon, and on a levelized basis, the cost to acquire all energy savings under the Achievable-Moderate scenario is $21.55/MWh.

**Table ES-2. Portfolio Energy Efficiency Cost Metrics by Time Horizon (Achievable-Moderate Scenario)**

| MILESTONE YEAR | TRC RATIO | SUM OF ANNUAL PROGRAM COSTS ($)[1] | SUM OF FIRST YEAR MEASURE SAVINGS (MWH) | FINAL YEAR DEMAND SAVINGS (MW) | ACQUISTION COST ($/MWH) | LEVELIZED COST ($/MWH) |
|---|---|---|---|---|---|---|
| 2021 | 2.08 | $6,957,787 | 38,083 | 5.28 | $182.70 | $15.25 |
| 2025 | 1.91 | $54,155,251 | 279,461 | 9.91 | $193.78 | $17.41 |
| 2030 | 1.72 | $164,148,094 | 797,374 | 17.25 | $205.86 | $20.18 |
| 2040 | 1.64 | $486,794,842 | 2,290,399 | 23.11 | $212.54 | $21.55 |
| **20-year avg.** | **1.64** | **$24,339,742** | **114,520** | 13.89 | **$212.54** | **$21.55** |

### Demand Response (DR) Resource

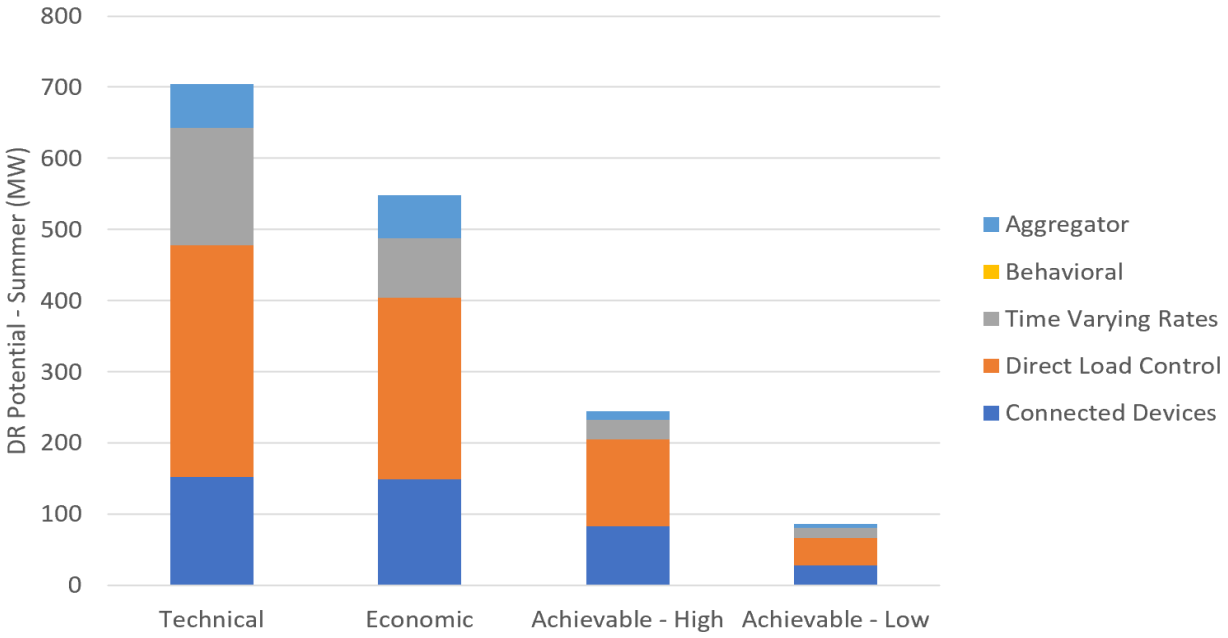
The study considered five different types of DR programs:

1. Aggregator – Capacity bidding programs managed by 3rd party aggregators
2. Behavioral – Personalized communication to customers requesting curtailed usage during peak events
3. Time varying rates – Customer retail electricity rates designed to shift usage by charging more during peak periods
4. Direct load control – Centralized remote control of customer equipment through installation of switches
5. Connected devices – Interaction with and control of internet-connected customer devices through web-based portals (e.g. Bring Your Own Thermostat programs)

Figure ES-2 shows the available DR potential across the portfolio by 2040 by program type. Connected device programs (primarily for Smart Thermostats) and Direct Load Control (DLC) (primarily for irrigation pumping) are the most significant program types.

[1] Includes administrative and incentive costs

**Figure ES-2. Portfolio Demand Response Potential by Program Type (2040)**




The DR analysis considered two different time-varying rates programs – **Critical Peak Pricing without Enabling Technology** (CPP no tech), and **Time Of Use** (TOU) – in each sector. Because Tri-State does not control customer rates, implementing a CPP or TOU rate demand response programs would require a high level of collaboration with electric cooperatives.

Table ES-3 summarizes the demand response cost metrics across the portfolio at each time horizon under the Achievable-Low scenario. By the end of the 20-year study horizon, the estimated 86 MW of peak demand savings is achievable at a cumulative total cost of $39 million. The Net Present Value TRC ratio of the demand response portfolio is cost effective by the end of the horizon (1.16 TRC), but not cost effective in the more immediate time horizons. This characteristic is largely driven by Tri-State's negligible costs of capacity until 2027.

**Table ES-3. Portfolio Demand Response Cost Metrics by Time Horizon (Achievable-Low Scenario)**

| MILESTONE YEAR | TRC RATIO | CUMULATIVE PROGRAM COST ($) | DR POTENTIAL (MW) |
|---|---|---|---|
| 2021 | 0.02 | $5,440,119 | 5 |
| 2025 | 0.09 | $13,818,802 | 30 |
| 2030 | 0.60 | $24,286,062 | 78 |
| 2040 | 1.16 | $39,068,285 | 86 |

## Distributed Energy Resource (DER)

The Team limited resources for the DER potential study to technologies that are behind-the-meter and owned by the customer; we did not consider market potential for supply-side resources within this assessment. The market potential assessment for DERs focused on solar photovoltaic (PV) systems across Tri-State's region for the period 2021 to 2040. We performed review and preliminary cost screens for other potential DER technologies such as combined heat and power and small wind but ultimately did not find these technologies applicable and/or cost effective.

Overall, solar PV generation has the technical capability of providing over half of Tri-State's sales. However, this value varies considerably by region. Figure ES-3 and Figure ES-4 below illustrate cumulative technically possible PV generation in 2040 compared to cumulative 2040 sales. It is interesting to note that in some areas of New Mexico solar power has the technical potential to produce more energy than is used. New Mexico's PV generation exceeds sales due to a high solar irradiance which improves solar efficiency and relatively low consumption on average.

**Figure ES-3. 2040 Technical Potential for Cumulative Residential PV Generation vs Sales by Region**

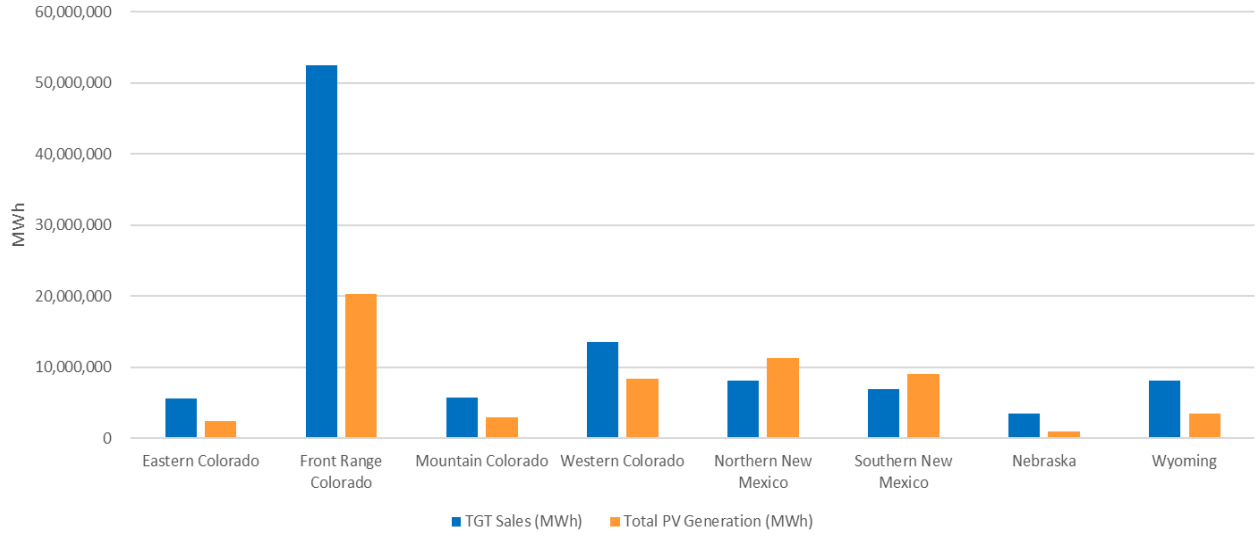
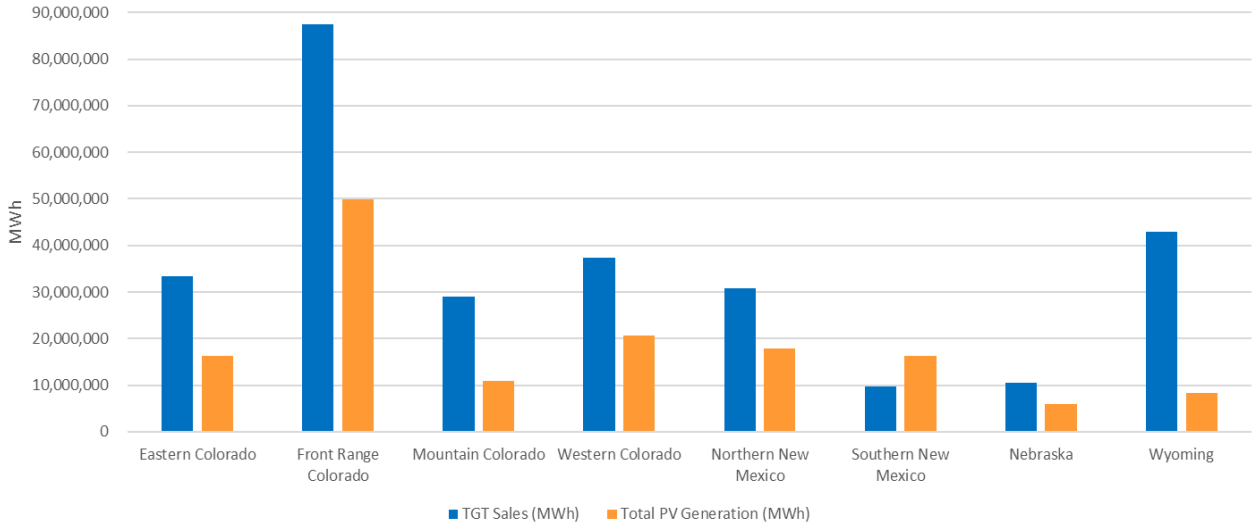
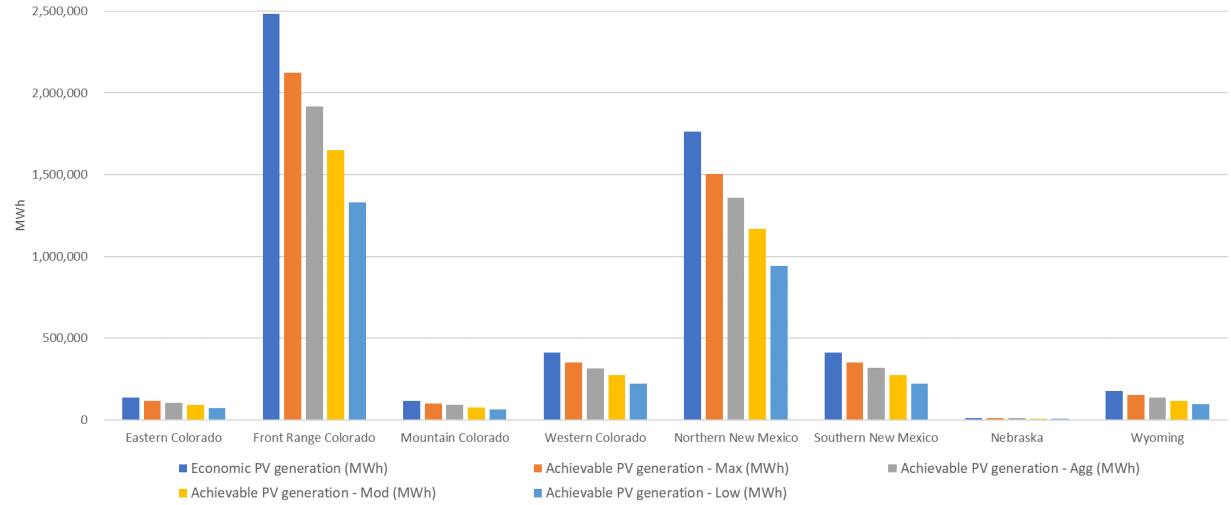


**Figure ES-4. 2040 Technical Potential for Cumulative Non-Residential PV Generation vs Sales by Region**




The results of the economic and achievable potential analysis are presented below in Figure ES-5. Only non-residential measures passed cost effectiveness, and those cost effective measures comprised just 9% of analyzed measure permutations. Cumulative non-residential economic potential solar PV generation equates to 2.0% of 2040 cumulative sales; achievable potential solar PV generation equates to 1.7% - 1.1% of 2040 cumulative sales. It is noted that while this potential generation reflect the entire Tri-State territory, the cost effective scenario used in this analysis includes $CO_2$ emission benefits which are not applicable to regions outside of Colorado, as emissions are not a quantifiable benefit at the time of this report publication.

**Figure ES-5. 2040 Cumulative Non-Residential Economic and Achievable Potential PV Energy Generation by Region**



## Results Summary

In summary, Tri-State and its member co-ops could save the following energy and dollars with the corresponding investment, on a levelized basis over the 20-year study period:

**Table ES-7. DSM Investment Outlook through 2040 (Achievable-Moderate Scenario)**

| RESOURCE TYPE | RESULTS |
|---|---|
| EE | Average annual savings of 114,520 MWH/year and 14 MW at a levelized cost of $15.25/MWH (TRC = 1.64) |
| DR | 86 MW of demand response potential by 2040 at a cumulative cost of $39M (TRC = 1.16) |
| DER | 3,661,295 MWH and 50 MW potential by 2040 at a cumulative administrative cost of $183M (TRC = 1.04) |

### Market Characterization & Baseline Forecast Results

In order to develop the results presented above, the Team developed a detailed characterization of Tri-Stat's customer base. This section summarizes the market and baseline forecast characterization including Tri-State's energy usage by sector and end use (additional details about customer segment and end use breakdowns within each sector are provided in Section 3). Tri-State's forecasted 2021 electricity sales to member cooperatives is just over 15 TWh, estimated to grow to just over 20 TWh by 2040 (Figure ES-6). In the base year of the analysis industrial is the largest market sector at 44% of load, followed by the residential sector at 30% of load, commercial at 18% and finally irrigation at 8%. These sector load shares remain fairly steady during the study horizon. The distribution of energy load by customer sector varies among the eight regions modeled in this study – for example, Eastern Colorado has a large irrigation sector load share while Mountain Colorado has almost no irrigation energy load (Figure ES-7). Front Range Colorado is the largest region at 5 TWh of energy load; it also has the largest Residential load share.

**Figure ES-6. Baseline Load Forecast by Sector by Milestone Year**

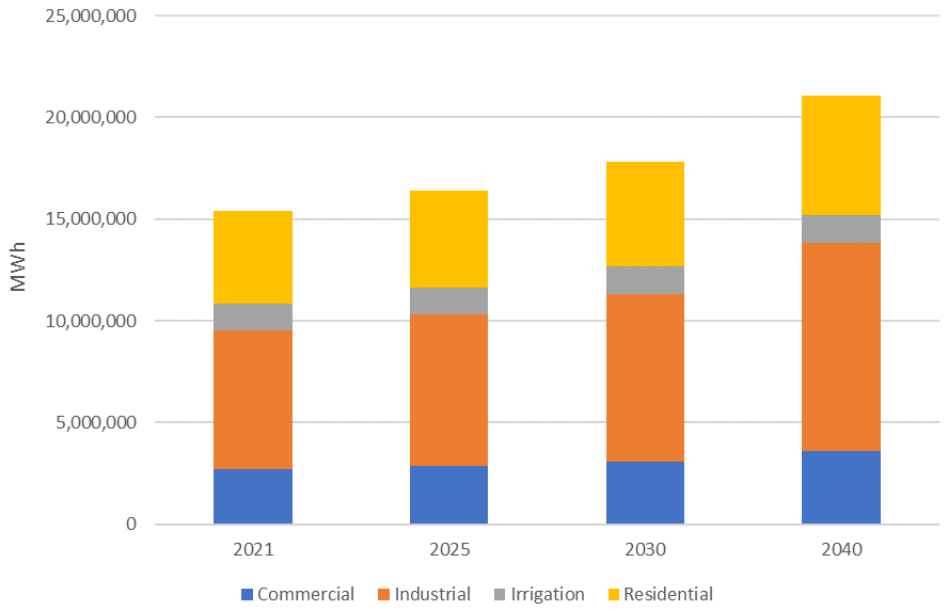
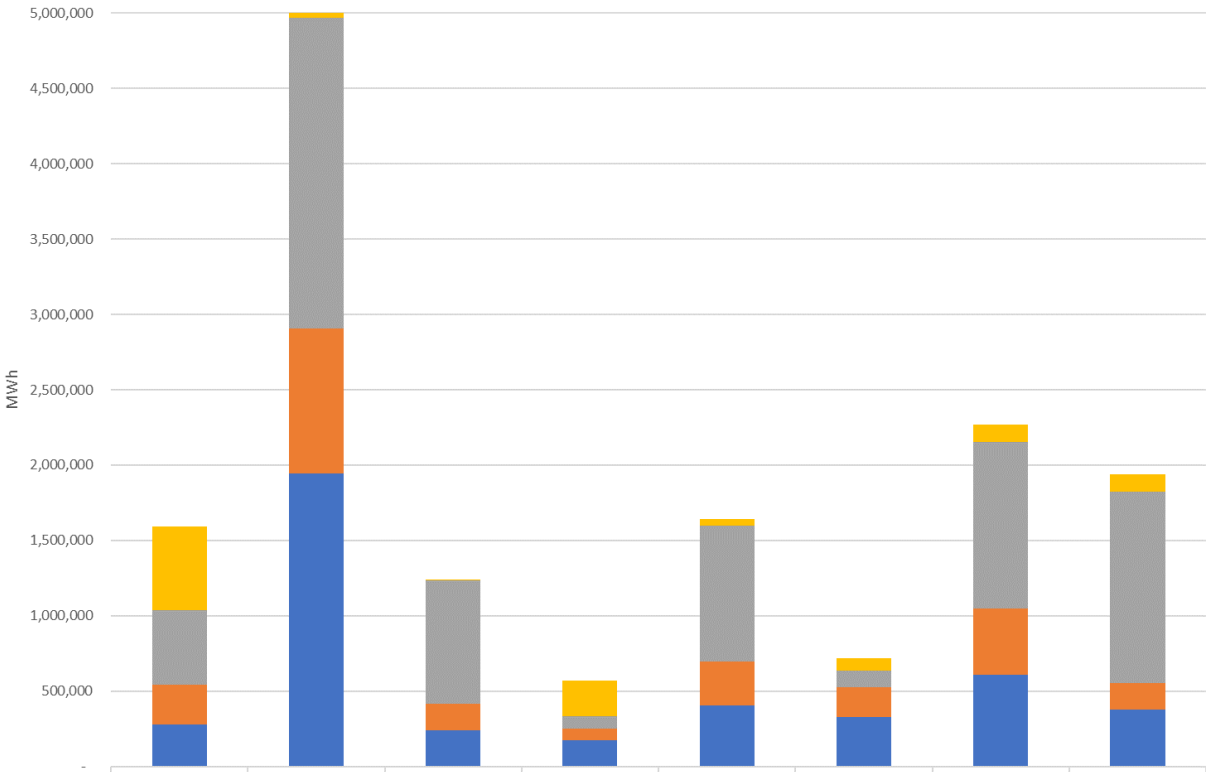


**Figure ES-6. 2018 Baseline Energy Load by Customer Sector by Region**




| | Eastern Colorado | Front Range Colorado | Mountain Colorado | Nebraska | Northern New Mexico | Southern New Mexico | Western Colorado | Wyoming |
|---|---|---|---|---|---|---|---|---|
| Irrigation | 554,724 | 31,967 | 861 | 237,972 | 41,763 | 85,091 | 116,352 | 119,890 |
| Industrial | 494,719 | 2,061,346 | 814,705 | 79,803 | 903,438 | 107,893 | 1,104,101 | 1,268,084 |
| Commercial | 268,177 | 964,547 | 176,453 | 78,733 | 289,986 | 197,934 | 444,417 | 173,590 |
| Residential | 276,257 | 1,944,118 | 241,514 | 173,762 | 406,734 | 328,318 | 606,582 | 380,071 |

## Study Approach and Methods

The study approach undertaken to develop the results presented above consists of three main tasks. These tasks are summarized below and discussed in more detail in Section 2 of this report. The tasks include:

- Customer Segmentation and Forecast Disaggregation
- Measure Impact Research
- Modeling and Data Analysis

**Segmentation and forecast**: For the market segmentation analysis, the Team collected relevant customer and forecast datasets from Tri-State to disaggregate customer energy load by region, sector, building/business type (i.e. segment), and end use for each year in the study's 20-year time horizon. This task identifies the available energy load within the various market and end use sectors available for conversion to higher efficiency or demand reduction technologies.

**Measure impacts**: With the market segemented and forecast disaggregated across the study horizon, the Team then characterized the universe of efficiency, demand response, and DER measures and their end-use-specific savings, costs, and lifetimes. Measures currently implemented in Tri-State's and Xcel Energy's DSM programs received careful consideration since these measures have a historical record and vendors have proven processes for implementation. Each measure was assigned to the relevant resource, region(s), sector(s), segment(s), and end use(s) for modeling. Each measure permutation was screened for cost effectiveness according the Total Resource Cost (TRC) test with a passing threshold of 0.7 for EE measures (thus allowing some less cost-effective measures to be assessed so long as the portfolio remained above a TRC of 1.0) and a passing threshold of 1.0 for DR and DER resources.

**Modeling and data analysis**: The Mesa Point Team used industry-standard modeling approaches to estimate the technical, economic, and achievable potential and associated costs for EE, DR and DER resources. Specifically, a discrete model was developed for each resource and potential estimates were developed independent of one-another – for example, each resource used the same baseline disaggregated load forecast and energy efficiency improvements did not reduce the opportunity for demand response potential. The energy savings and associated costs of each resource was forecasted for a 20-year time horizon (2021 – 2040). Two to four achievable potential scenarios were developed for each resource so that varying levels of market opportunities could be assessed given variances in measure incentive levels and aggressiveness of program delivery. Outputs from each resource model were developed at high levels of resolution, showing annual energy savings, lifetimes, and costs for each measure permutation (by region, sector, segment, end use, and vintage) for each year of the study horizon.

# 1. INTRODUCTION

## 1.1. Background, Project Scope, and Objectives

Tri-State retained Mesa Point Energy, along with their subcontractor Brightline Group, (collectively the Mesa Point Team or the Team) to perform a demand side management study in support of the company's resources planning initiatives. The primary objective of this study is to assess the available technical, economic, and achievable energy savings potential from energy efficiency (EE), demand response (DR), and behind-the-meter distributed energy resources (DER) from 2021 to 2040 for the electric cooperatives served by Tri-State Generation and Transmission (Tri-State). Measures considered are limited to technologies that are behind-the-meter and owned by the end-user.

The potential study is intended to assist Tri-State in developing their Integrated Resource Plan (IRP) and Electric Resource Plan (ERP). Tri-State will use the results of this market potential study to analyze and incorporate potential EE, DR and DER impacts at various levels of program investment over the planning horizon from 2021 to 2040.

The study focuses on energy efficiency, DR, and DER *achievable* potential. As discussed further in Section 2, the study is not a *program* potential study meaning it does not take into consideration program budget and design constraints. Therefore, this report's conclusions and recommendations do not include program-specific recommendations; rather, the report focuses on identifying market opportunities and costs for EE, DR, and DER.

## 1.2. Achievable v. Planned Savings

This potential study examines what *could be* (i.e., what savings could accrue from considered cost effective measures) but does not account for structural and organizational limitations to that potential.

Tri-State member cooperatives are responsible for implementing measures and programs on a voluntary basis. Tri-State does not have control over which measures its members choose to offer nor how the measures are bundled into program offerings. Some co-ops may choose not to offer incentive programs, or to incent only a subset of cost-effective measures.

The study only takes into consideration barriers on the market side and does not attempt to predict if and at what levels co-ops will choose to move forward with programs.

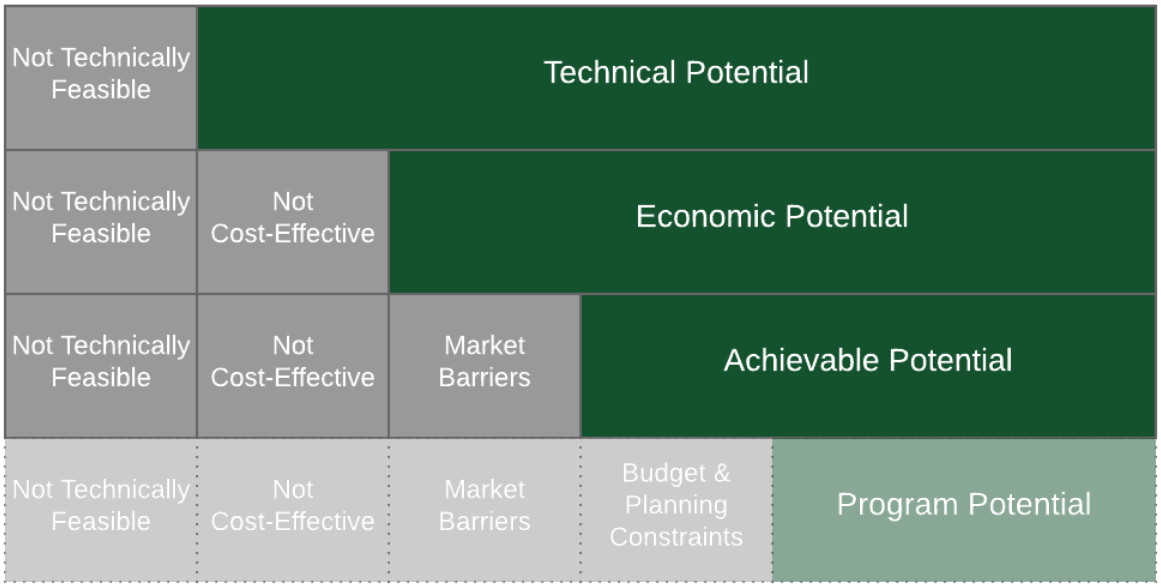
## 1.3. Study Approach Overview

In accordance with standard industry practice for DSM potential studies, this study considers measures from the perspective of theoretical maximum savings, and then accounts for barriers to estimate actual achievable savings.

Specifically, the study begins with *technical potential*, wherein all technically viable measures are included without regard to costs or other barriers. Knowing the technical potential, *economic potential* is assessed by estimating costs to implement measures, and then applying economic criteria to the measures. Finally, *achievable potential* is calculated by considering non-economic factors affecting DSM measure implementation. Not considered in the report are factors affecting *program potential*.

This analysis approach is based on standard perspectives of DSM resource potential according to the Environmental Protection Agency's (EPA) National Action Plan for Energy Efficiency (NAPEE)[2] as illustrated in Figure 1.

**Figure 1: Conceptual Overview of DSM Resource Potential Defintions**




- **Technical Potential** is the theoretical maximum amount of energy and capacity that could be displaced by an efficient technology, regardless of cost and other barriers that may prevent the installation or adoption of a measure. Technical potential is only constrained by factors such as technical feasibility and applicability of measures.
- **Economic Potential** is the amount of energy and capacity that could be reduced by measures that pass a cost-effectiveness test. This analysis used the Total Resource Cost (TRC) Test, which estimates the measure costs to both the utility and customer.
- **Achievable Potential** is the energy savings that can feasibly be achieved through program and policy interventions. Achievable potential takes into account barriers that hinder consumer adoption of energy efficiency measures such as financial, political and regulatory barriers, and the capability of programs and administrators to ramp up activity over time.
- **Program Potential** reflects the realistic quantity of energy savings the utility can realize through DSM programs during the horizon defined in the study. Potential delivered by programs is often less than achievable potential due to real-world constraints such as program budgets, effectiveness of outreach, and market delays. Program potential would also incorporate go-to-market considerations, such as practical limitations for Tri-State to deliver programs to

[2] The EPA National Action Plan for Energy Efficiency: http://www.epa.gov/cleanenergy/documents/suca/napee_report.pdf

customers through the rural electric cooperative members. As noted previously and as shown in Figure 1, this study does not address program potential.

## 1.4. Cost Effectiveness

At the core of DSM potential is the concept of cost-effectiveness. To assess cost effectiveness, the total cost of implementing measures is compared to the cost of business as usual with energy being provided to the baseline energy using equipment and behaviors. A DSM measure is considered cost effective if it is less costly than simply providing energy to baseline systems.

The California Standard Practice Manual (SPM) provides the methodology for estimating cost effectiveness of technologies, bundles, programs, or portfolios based on a series of tests representing the perspectives of the utility, customers, and societal stakeholders. "Low," Moderate ("Mod"), Aggressive ("Agg"), and Maximum ("Max") scenarios vary based on the assumptions for level of incentive, staffing, and marketing investment.

## 1.5. Presentation of Savings

This report represents savings in several different ways. For the most part, savings across years is presented as cumulative, but there are cases in which the savings may be presented in one of the other ways defined below. Following are the various methods for presenting savings:

- **Annual Incremental**: Energy savings acquired in the year in which measures are installed
- **Cumulative**: Total energy savings acquired over a given time horizon, accounting for measure decay (i.e. retired energy savings after an installed measure reaches the end of its useful life)
- **Sum of Annual Incremental**: Total energy savings acquired over a given time horizon, not accounting for measure decay

## 1.6. Organization of the Report and Related Deliverables

This report presents a summary of the analysis approach, key assumptions and study findings. Two separate electronic reporting tools serve as an appendices to the report. The tools provide the ability to view findings by sector, end-use, and region from both annual and hourly perspectives. The intent is for Tri-State and stakeholders to make use of both work products depending on the desired level of detail. Figure 2 summarizes the structure for the remainder of this report.

**Figure 2. Summary of Report Structure**

**Section 2**

- Describes the study approach and methods.

**Section 3**

- Discusses the team's efforts to disaggregate and analyze Tri-State's baseline forecast. That work serves as the foundation for the analysis and findings presented in the remainder of the report.

**Sections 4-8**

- Present sector-level findings for energy efficiency potential.

**Section 9**

- Presents findings for the demand response potential analysis.

**Section 10**

- Presents findings from the distributed energy resource (DER) potential analysis.

**Section 11**

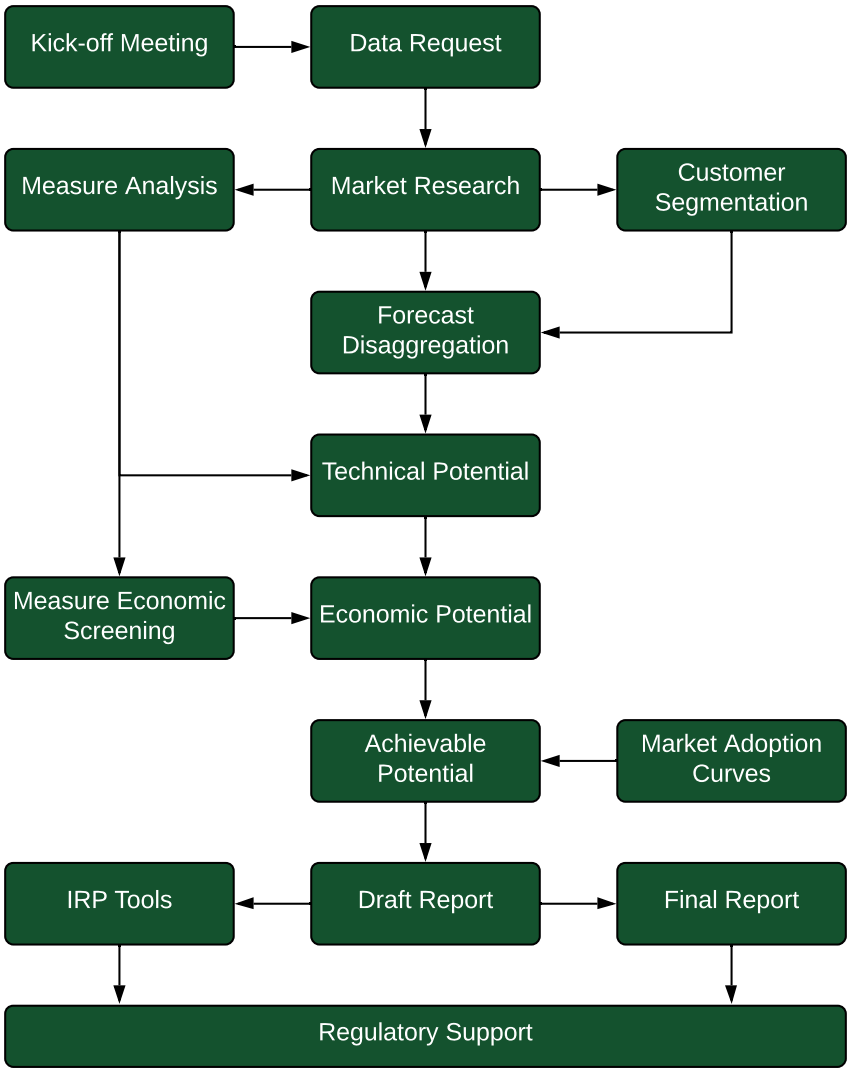
- Presents overall findings and recommendations.

# 2. STUDY APPROACH AND METHODS

## 2.1. Overview

The process shown in Figure 3 depicts the steps taken during a market potential study.

**Figure 3. Approach for Demand Side Resource Potential Modeling**




These steps generally apply to all three demand-side management (DSM) resources considered: energy efficiency, DR, and DER. Each step is described in detail in the sections that follow. Sections 2.2–2.4 generally apply across all three resources. Sections 2.5 and 2.6 provide additional detail for the approach and methods used for the DR and DER analyses.

## 2.2. Customer Segmentation and Forecast Disaggregation

An accurate assessment of achievable savings potential requires a thorough characterization of the baseline energy usage. This characterization involves the following steps:

- Determine the energy consumption per region, customer class and segment in baseline year.
- Disaggregate customer class loads into end-use loads, such as water heating.
- Analyze and calibrate data to 2018.
- Forecast the 20-year end-use energy consumption through 2040.

To complete these steps the Team relied on a large dataset consisting of:

- Information on Tri-State member cooperative customers
- Historical loads
- Market data including fuel shares, equipment saturations, and structural characteristics
- End-uses including energy use intensities and load shapes
- Measure characteristics including technologies, costs, life, and savings

These data were drawn from a combination of primary and secondary research. An overview of the steps involved in this process follows. The findings of the market characterization is presented in Section 3.

### 2.2.1. Customer Segmentation

To begin, the Team analyzed the portion of Tri-State's forecasted sales attributable to DSM-ineligible accounts. This included the share of the load that is served by re-sale customer or non-premise accounts. This portion of the load was removed from the load considered eligible for energy efficiency and demand reduction measures.

Next the Team determined energy and demand loads for the appropriate regions, sectors, market segments, vintages, and end-uses as follows:

- **Regions**: Sales for rural electric cooperatives were aggregated into regional definitions; including Front Range Colorado, Nebraska, North New Mexico, Wyoming, etc., as shown in Table 1.
- **Customer Sectors**: Residential, commercial, irrigation, and industrial (including agricultural)
- **Market Segments:**
  - **Commercial**: Typically based on major Commercial Buildings Energy Consumption Study (CBECS) business types.
  - **Industrial**: All major industrial segments in Tri-State service territory using NAICS classification from the Form 345 information.
  - **Residential and Irrigation**: No further segment-level breakdown

- **Vintages:** Existing and New Construction
- **End-uses:** Those shown by sector in Table 2

#### 2.2.1.1. Primary Market Research

Primary market research guided customer segmentation. In 2012, Tri-State distributed a mail-in residential end-use survey requesting information on consumers' residence structure and energy consuming equipment type, age, fuel type, end-uses, and behavior. The survey yielded over 300 customer responses, with each cooperative providing a minimum confidence level of 90% with 10% precision for each surveyed technology at the cooperative level. This data was used to guide the disaggregation of the residential sector load.

The Team also used North American Industry Classification System (NAICS) data that provides business type data on large customers (greater than 250KW) and their associated energy consumption from the Rural Utilities Service (RUS) Form 345. Business type information for energy sales of non-residential customers less than 250KW was not available. Secondary research was necessary to estimate segmentation of business types for customers less than 250KW.

#### 2.2.1.2. Secondary Market Research

The Team utilized secondary resources to complete the customer segmentation. Examples of these resources include the 2010 Tri-State System-Wide Electric Energy Efficiency Potential Study , United States Energy Information Administration (EIA) Residential Energy Consumption Survey (RECS)[3], the EIA Commercial Buildings Energy Consumption Survey (CBECS)[4], 2016 NorthWestern Energy End-Use and Load Profile study[5], the 2015 Platte River Power DSM Potential Study, among other references.

### 2.2.2.Segmentation of Regions

To accurately characterize Tri-State's large geographic service territory, the Team segmented end-use load profiles and energy efficiency potential by region. Eight (8) regions were defined based on geographic location of the co-ops[6]. Segregating the co-ops by region, instead of producing one set of potential values for all of Tri-State's territory has several advantages:

- Energy efficiency measures more accurately match building codes in each region. For example, envelope construction requirements are different depending on climate zone.

[3] *https://www.eia.gov/consumption/residential/*

[4] https://www.eia.gov/consumption/commercial/

[5] https://www.northwesternenthinkergy.com/docs/default-source/documents/etac/2017/nexant_energy_end_use_and_load_profile_study.pdf

[6] This report and the associated Reporting Tool, described in this report, utilize the regional breakdown characterized here. The Load Shape Tool, also described in this report, utilizes an adapted breakdown to accommodate for member coops that cross certain regional boundaries. This alternative breakdown of potential savings is to allow for more accurate output data for input into Tri-State's resource planning models. The adjustment reflects where coop service territory extends across eastern and western interconnects.

- Regional segmentation captures a higher resolution of equipment end-use saturation and energy intensity. For instance, direct expansion (DX) cooling in the residential sector has a higher saturation and energy intensity in southern New Mexico as compared to northern Wyoming.
- This segmenation accommodates regional cost variances for participant energy efficiency implementation or utility avoided costs.
- Barriers to achievable potential may be regionally specific.

Based on evaluation of climatic impacts, sector segmentation and end-uses, the Team developed the regional electric cooperative groups shown in Table 1.

**Table 1: Tri-State Cooperative Regional Groups**

| EASTERN COLORADO | FRONT RANGE COLORADO | MOUNTAIN COLORADO | WESTERN COLORADO |
|---|---|---|---|
| Highline | Mountain View | Gunn County | Empire |
| K.C. | Poudre Valley | Mountain Parks | La Plata |
| Morgan County | San Isabel | White River | San Luis Valley |
| Southeast | United | | San Miguel |
| Y-W | | | Sangre De Cristo |
| **NEBRASKA** | **SOUTHERN NEW MEXICO** | **NORTHERN NEW MEXICO** | **WYOMING** |
| Chimney Rock | Central NM | Cont. Divide | Big Horn |
| Midwest | Columbus | Jemez Mtns | Carbon |
| Northwest | Otero County | Mor San Miguel | Garland |
| Panhandle | Sierra | North. Rio Arriba | High Plains |
| Roosevelt | Socorro | Southwestern | High West |
| Wheat Belt | | Springer | Niobrara |
| | | | Wheatland |
| | | | Wyrulec |

## 2.3. End-Use Load Classification

To further disaggregate the load the Team established end-use loads within each sector.[7] Table 2 presents a summary of those end-uses.

[7] The irrigation sector is solely composed of the motor end-use.

**Table 2: End-Uses for Each Tri-State Sector**

| RESIDENTIAL | COMMERCIAL | INDUSTRIAL |
|---|---|---|
| Central Air Conditioning | Cooking | Lighting |
| Central Heating | Cooling | HVAC |
| Clothes Washer | Heat Pump | Motors |
| Dishwasher | HVAC Aux | Pumps |
| Electric Cooking | Lighting | Process Heat |
| Electric Dryer | Plug Load | Process Cool |
| Freezer | Refrigeration | Pumps |
| Exterior Plug Load | Space Heating | |
| HVAC Aux | Water Heating | |
| Heat Pump | | |
| Lighting | | |
| Plug Load | | |
| Refrigerator | | |
| Second Refrigerator | | |
| Room AC | | |
| Electric Water Heater | | |

The primary regional inputs needed to model each end-use were the total premise count, fuel shares, end-use Unit Energy Consumption (UEC), and saturation. Expected improvements in building energy code requirements and other general trends were incorporated into the UECs based on data found in the U.S. Energy Information Administration's forecasts. In general these trends showed a decrease in all end-use UECs with the exception of plug loads, which showed an increasing trend.

### 2.3.1.Codes and Standards

There is uncertainty about future federal standard updates and enforcement. While the study considers current codes and standards, the analysis is not intended to predict how or when energy codes and standards will change over time. As a result, there are only limited known improvements to federal codes and standards to reasonably account for in this analysis.

The primary adjustment made in the Team's methodology impacts residential screw-in lighting. Based on the current Department of Energy final rule that did not trigger the Energy Independence and Security Act (EISA) backstop, the potential analysis does not model Tier II EISA efficiency requirements. However, the study does model the transitioning screw-based lighting market that is rapidly being

saturated with LED technology. The Team modeled this market transition by limiting the future potential for residential lighting starting in 2027. The analysis assumes only a limited number of direct-install screw-based lighting opportunities for standard, specialty, and reflector bulbs over the latter analysis period.

Although not exhaustive, the following list outlines additional key standards the Team considered:

- The baseline efficiency for air source heat pumps (ASHP) is anticipated to improve to 15 SEER/8.8 HSPF.
- The baseline efficiency for split system central AC systems is anticipated to improve to 14 SEER in 2023.
- In July 2019, the DOE makes new standards effective for more efficient furnace fan/motors. The standards are expected to improve the efficiency by approximately 45% over the current baselines. The new standard will create a shift to electronically commutated motors (ECMs).

## 2.4. Energy Efficiency Potential Modeling

Drawing on outcomes from of the disaggregated the Team modeled first technical, then economic, and finally achievable energy savings potential. Those steps are described in the following sections.

### 2.4.1. Estimate Technical Potential

Technical potential is the theoretical maximum amount of energy use that could be displaced by efficiency, disregarding all non-engineering constraints such as cost-effectiveness and the willingness of end-users to adopt the efficiency measures. Technical potential is only constrained by factors such as technical feasibility of measures. The model applies the measure-level inputs to the disaggregated baseline sales forecast to estimate technical savings and demand reduction potential over the planning horizon.

As an example, the core equation used in the residential sector energy efficiency technical potential analysis for each individual efficiency measure is shown in Equation 1.

**Equation 1. Core Equation for Residential Sector Technical Potential**




Where:

***Total Number of Households*** *= Count of customer households in the subject region.*

***Base Case Equipment Energy Use Intensity*** *= the electricity used per customer per year by each base-case technology in each market segment. In other words, the base case*

*equipment energy-use intensity is the consumption of the electrical energy using equipment that the efficient technology replaces or affects.*

***Saturation Share =*** *the fraction of the end-use electrical energy that is applicable for the efficient technology in a given market segment. For example, for residential water heating, the saturation share would be the fraction of all residential electric customers that have electric water heating in their household.*

***Remaining Factor =*** *the fraction of equipment that is not considered to already be energy efficient. To extend the example above, the fraction of electric water heaters that is not already energy efficient.*

***Applicability Factor =*** *the fraction of the applicable units that is technically feasible for conversion to the most efficient available technology from an engineering perspective—i.e., it may not be possible to install a heat pump water heater in all homes due to space constraints.*

***Savings Factor =*** *the percentage reduction in electricity consumption resulting from the application of the efficient technology*.

#### 2.4.1.1. Measure Definitions

Once the baseline forecast is disaggregated, the next step to assessing technical market potential is to accurately detail the universe of efficiency measures and their end-use-specific savings, costs, and lifetimes. Measures currently implemented in Tri-State's and Xcel Energy's DSM programs received careful consideration since these measures have a historical record and vendors have proven processes for implementation. Additionally, our Team compiled all measures available from such sources as the Pacific NorthWest Regional Technical Forum (RTF), Xcel Energy's Demand Side Management Plan, and technical reference manuals (TRMs) from jurisdictions like the states of New Mexico, Pennsylvania, and Minnesota. The Team also leveraged measure data it has characterized in similar studies. From these regionally relevant databases, the Team selected measures that are commonly available, based on well-understood technology, and applicable to the buildings and end-uses in Tri-State's service territory. The Team also considered measures that show promise for future viability but have not yet gained a foothold in the market.

Energy efficiency measures are characterized in three main vintages:

- **Replace on Burnout:** As equipment replacements are made normally in the market when a piece of equipment is at the end of its effective useful life (also referred to as "turnover").
- **Retrofit:** At any time in the life of the equipment or building (referred to as "early-retirement").
- **New:** When a new home or building is constructed.

Upon finalizing the energy efficiency measure list, the Team collected data on energy savings, costs, lifetime, and applicability to determine potential measure impacts. This work involves a multi-step process described here.

***Step 1: Define market classifications for application of measures***

The Team established market classifications as a framework for documenting applicability of each measure. These classifications were based on factors including region, fuel type, sector, market segment, and end-use as defined in the disaggregated forecast (Section 2.2). Additionally, the Team further defined permutations for each measure based on the following parameters:

- **Climate Zone:** This measure research includes savings estimates for weather-dependent measures specific to ASHRAE climate zones 4 through climate zone 6
- **Measure Type:** Equipment vs. Non-equipment
- **Vintage:**
  - **Equipment** – Turnover, Retrofit, New
  - **Non**-equipment – Existing, New

***Step 2: Screen sectors, segments, and end-uses for eligibility***

The Team screened market segments and end-uses for applicability of specific energy efficiency measures. For example, certain commercial end-uses, such as cooking, may not be appropriate for segments such as offices and warehouses and therefore were analyzed only in limited market segments.

***Step 3: Develop base case impacts and costs***

The Team determined base case equipment and practices for each of the energy efficiency measures on the final list, and developed a description and rationale for each. This included all base case assumptions and data, such as state building codes (the 2012 International Energy Conservation Code (IECC) in most cases) and federal standards. Base case assumptions included projected future adjustments, such as upcoming federal standards.

***Step 4: Develop energy efficiency measure impacts and costs***

The Team developed a description of all energy efficiency (or "change case") measure equipment and practices, including all measure energy savings assumptions and calculation parameters, such as equivalent full load hours (EFLH). For each measure, the Team estimated energy savings as a percentage of base equipment and/or end-use consumption.

In addition to energy savings, the Team collected incremental measure costs pertinent to Tri-State's service territory from appropriate TRM references and internet retailer data and researched measure life drawing on TRM documentation.

#### 2.4.1.2. Screw-in Lighting

The Team reviewed the residential, commercial, and industrial lighting measures and lighting end-use assumptions to incorporate recent changes to the lighting market. This included reviewing and updating savings, measure cost, saturation, and expected useful life assumptions for each lighting measure. Based on federal policy projections, the Team made the assumption that the EISA "backstop" would not be enacted beginning in 2020. Additionally, the Team characterized the lighting market to transform primarily to an LED baseline for screw-in lighting by the end of the decade.

### 2.4.2. Estimate Economic Potential

Economic potential represents the savings possible given full adoption of all cost-effective efficiency measures. For this study, the Team utilized the Total Resource Cost (TRC), which is commonly considered the preferred test to assess measure benefits and costs from the perspective of the utility and society as a whole. Equation 2 presents the TRC ratio equation.

***The benefits in the TRC test are the net present value of the lifetime avoided energy and capacity costs. The costs in this test are the net present value incremental measure costs.***

**Equation 2. TRC Ratio**

$$\textbf{TRC Ratio} = \textbf{NPV}(\textbf{Avoided Costs})/\textbf{NPV}(\textbf{Incremental Measure Costs})$$

Where*:*

$$\text{Avoided Cost} = \text{NPV}\left(\sum_{\text{year}=1}^{\text{measure life}}\left(\sum_{\text{i}=0}^{\text{i}=8760}(\text{impact}_{\text{i}} \times \text{avoided cost}_{\text{i}})\right)\right)$$

The **benefits** include the net present value of the energy and capacity saved by the measures along with any natural gas or other fossil fuel benefits. The forecast of electric avoided costs of energy and capacity were obtained from Tri-State and represent their most recent forecast of avoided electric benefits. The avoided costs are calculated by applying end-use-specific annual hourly load shapes to measure savings impacts and determine the time-differentiated value of energy and capacity benefits. The annual hourly load shapes were developed from industry-specific energy load profiles, and a peak definition (noon – 22nd hour in weekday summer months) was provided by Tri-State to estimate coincident peak demand.

To accurately value avoided energy savings for Tri-State, the expected losses were estimated from the customers' meters to Tri-State's generation source. These losses were calculated for each climate zone, and reflected the losses from the customer to the co-op and the losses from the co-op to Tri-State. In addition to line losses, a discount rate of 5% was applied to value future avoided costs.

The **costs** are the net present value of all costs to implement those measures. These costs include full incremental costs (both utility and participant contributions), but no incentive payments that offset incremental costs to customers and no lost revenues. The full incremental costs include single upfront costs and operational & maintenance costs where applicable. Incentives are not included, because they are transaction between the utility and customer, thus the costs and benefits negate each other. While non-incentive costs were not included in the measure-level screening of electric energy efficiency potential, they were included in further assessments of potential at the achievable potential level described below.

Additionally the social cost of carbon at $46/ton of carbon dioxide ($CO_2$) was incorporated as an avoided benefit in the TRC calculations. This value was escalated annually over the study time horizon based on figures provided by Tri-State.

The measure screen from technical potential to economic potential utilized a cost-effectiveness hurdle of 0.7 in order that the sector level TRC test would be closer to 1.0. This reduction in the screening threshold permits non cost-effective measures into the portfolio so that a potential program

intervention is more well-rounded and can include a limited number of non-cost-effective measures. However, the forecasted sector portfolio must have an estimated TRC greater than 1.0 when program administrative costs are included.

### 2.4.3. Estimate Achievable Potential

Finally, the assessment of realistically achievable energy efficiency potential required estimating, among other parameters, the rate at which cost-effective measures can be adopted over time. The Team incorporated individually developed sets of market penetration curves corresponding to implementation scenarios to account for the fact that program implementation scenarios have a direct influence over such market penetration rates. These scenarios were correlated to differing levels of urgency in program implementation, tolerance for rate impacts, macroeconomic conditions, and other situations.

The following are important components in determining achievable potential:

- **Benchmarking.** The amount of savings expected to be achievable through DSM programs will be informed by the experience of utilities across the region and nation.
- **Customers' willingness to participate.** The likelihood that customers will participate in energy efficiency programs is a function of several factors, most notably incentive level.
- **Uncertainty.** Planning requirements often necessitate a point-estimate of potential, however, this is not an accurate reflection of the reality of DSM programs. We prefer to think of achievable potential as a range, or probability distribution, where the point-estimate is the most likely outcome. This distribution defines the lower and upper bounds of expected savings, as well as the most likely value.

Achievable potential energy efficiency impacts were evaluated based on four incentive scenarios as a function of the incremental costs of efficiency measures:

- 25% "Low"
- 50% Moderate ("Mod")
- 75% Aggressive ("Agg")
- 100% Maximum ("Max")

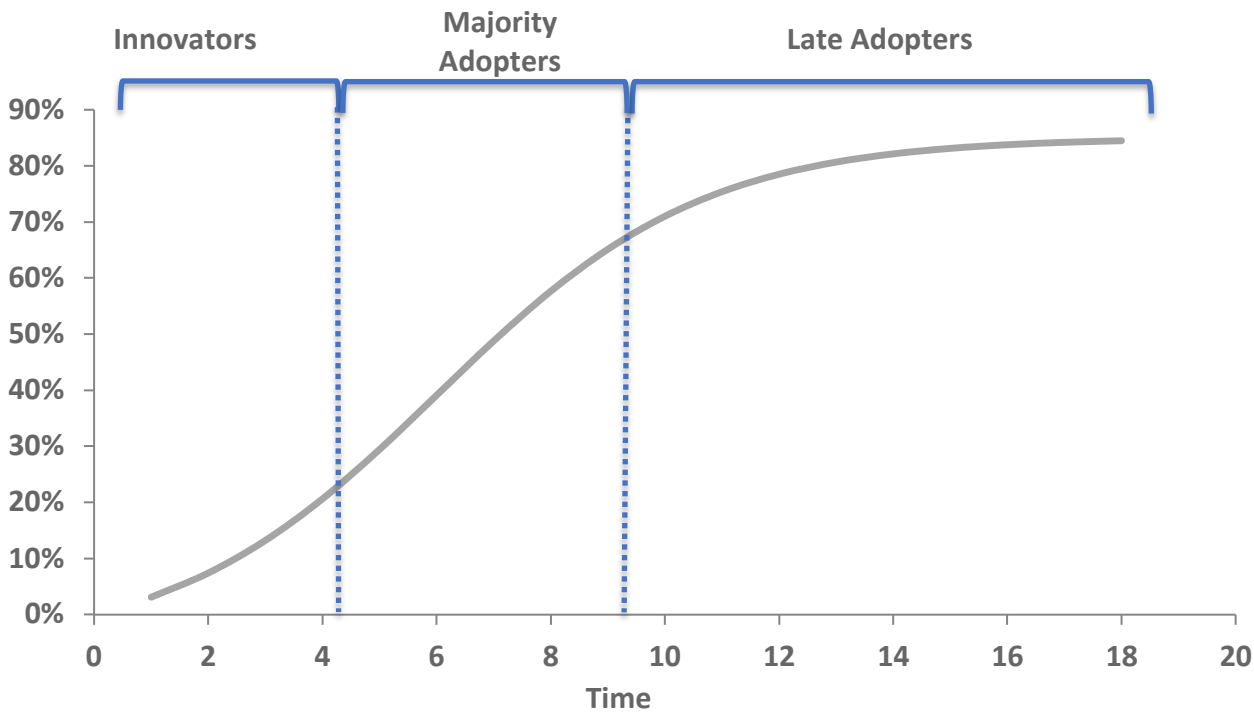
For instance, the moderate scenario approximates the market adoption achievable by incentivizing 50% of the incremental cost of the measure. Results are presented from the perspective of the Achievable Moderate scenario unless otherwise specified. This scenario represents a reasonable progression from Tri-State's current program offerings.

#### 2.4.3.1. Market Adoption Rates

In order to characterize the rate of market adoption for each of the specified scenarios, the Team developed a quantitative approach based on a Bass Diffusion Model. This method relies on scientific theory and historic program participation data based on Tri-State experience and other DSM programs in North America.

The Bass Diffusion Model is a mathematical description of how the rate of product diffusion in a market changes over time. When the product is introduced, there is a slow rate of adoption while customers become familiar with the product. When the market accepts a product, the adoption rate accelerates to relative stability in the middle of the product cycle. The end of the product cycle is characterized by a low adoption rate because fewer customers remain that have yet to adopt the product. This concept of forecasting future adoption rates is illustrated in Figure 4.

**Figure 4: Typical Product Diffusion in the Marketplace**




The rate of adoption in a discrete time period is determined by external influences on the market, internal market conditions, and the number of previous adopters.

- Initial Year Measure Adoption
  - First year adoption levels were informed by recent Tri-State historical performance where possible.
- Long-Term Market Adoption Rates
  - The final adoption scores that resulted from willingness to pay surveys serve as the point-estimate for the long-term market adoption potential for the realistic achievable scenario.
- Adoption Curve Shape
  - Once the initial year adoption rate (Point A) and long-term adoption rates (Point B) are determined, the remaining step was to determine the rate and duration to get from Point A to Point B.

Unique end-use adoption curves were developed based on the following three parameters:

- **Customer Sector:** Residential, Commercial, and Industrial
- **End-Use**: Lighting, Motors, etc.
- **Incentive Level based on Achievable Scenario**: 25%, 50%, etc.

#### 2.4.3.2. Program Costs

Finally, to capture the full cost of achievable energy efficiency potential, the Team added program non-incentive costs in the overall assessment of cost-effectiveness. Non-incentive program cost categories included: (1) Administration, (2) Marketing, (3) Technical, and (4) Measurement & Verification and Planning. Program non-incentive costs were calculated on a gross $ per first-year kWh saved. Non-incentive costs were developed for each program by sector. The included program cost assumptions are shown in Table 3.

**Table 3: Summary of Non-Incentive Program Costs ($/kWh)**

| SECTOR | ACHIEVABLE LOW | ACHIEVABLE MOD | ACHIEVABLE AGG |
|---|---|---|---|
| **Residential** | $0.100 | $0.115 | $0.150 |
| **Commercial** | $0.050 | $0.058 | $0.075 |
| **Industrial** | $0.100 | $0.115 | $0.150 |
| **Irrigation** | $0.050 | $0.058 | $0.075 |

### 2.4.4. Data Analysis and Reporting Tool

A set of dynamic analysis tools were developed to provide Tri-State staff access to the data outputs from the modeling efforts. These consist of a Reporting Tool and a Load Shape Tool specifically created for this project. The Reporting Tool summarizes and illustrates the savings potential and associated costs by sector, year, and scenario enabling the user to select results for a specific region or for the entire service territory. The results are depicted in tabular form and in associated charts that update dynamically based on the selected region.

The Load Shape Tool was developed to convert the model's annual energy savings and cost outputs into 8760 hourly load profiles for direct input into Tri-State's ERP planning tool. The tool bundles and maps measures to associated 8760 hourly load profiles to illustrate at what hours during the day and year energy savings are likely to be incurred for each bundle of measures. The tool also shows the associated levelized cost of each bundle of measures on an 8760-hourly basis. The data is represented by sector, interconnect region, scenario, and load shape bundle. This tool will allow Tri-State to compare energy efficiency resource savings and levelized costs and compare them with other supply-side and demand-side resources during its ERP development process.

## 2.5. Demand Response Potential Assessment

Demand response refers to the reduction of electric demand by way of altering the operation of some piece of technology or equipment. Demand response programs take several forms, but most rely on

direct control of energy-using equipment via communication infrastructure like radio or WiFi or the change in customer behavior from time-based rates.

There are a few important differences between the assessment of demand response programs and other demand-side management options, such as energy efficiency. First, demand response programs require active, ongoing participation by customers. Second, unlike energy efficiency programs, demand response is designed to shift load from peak periods of energy use to non-peak periods, which can affect the availability of service to the customer. These programs use independent concepts and technologies and not 'upgrades' in the sense that energy efficiency measures are upgrades from some similar baseline option. These programs use independent concepts or technologies and are not 'upgrades' in the sense that energy efficiency measures are upgrades from similar baseline options. Thus, demand response technologies have no incremental cost. Finally, demand response depends on a customer's willingness to participate in individual events. This willingness to participate is a function of program design, which includes the number of events, incentive levels, the stipulation of mandatory or voluntary participation, and the existence of penalties for non-compliance. Hence, estimating demand response potential involves in a number of steps. The final potential number is a product of the base peak demand, eligibility rates, technical load impact rates, program participation rates, and event participation rates.

#### 2.5.1. Estimate Peak Demand

Coincident peak demand data was available for each of the eight regions in the Tri-State system. This system-level peak demand was divided to estimate the contributions from each sector (residential, irrigation, commercial, and industrial) by using sector energy use during the peak month relative to the system energy use during the same time period. Per premise demand estimates were generated by dividing by the number of premises in each sector.

#### 2.5.2. Apply Eligibility Rates

Eligibility rates customized to each program were applied to the base peak demand to determine the peak load eligible to participate. For example, a Direct Load Control (DLC) program capturing residential central HVAC load will require premises to have central air conditioners, while a Smart Thermostat DR program would additionally require the residence to have broadband service and a WIFI network. Irrigation load reduction is generally limited to customers with pumping power greater than 75 horsepower. Commercial and industrial customers in a capacity bidding program typically need to have a peak demand of greater than 250 kW.

#### 2.5.3. Estimate Technical DR Potential

Technical potential for demand response is the theoretical maximum level of peak demand that could be curtailed through DR programs. This scenario disregards non-engineering constraints such as cost-effectiveness and willingness of end-users to enroll. All eligible customers are modelled as if enrolled in one or more DR programs and participating in DR events.

In the Technical Potential scenario, care must be taken to avoid double-counting participation in programs that affect the same end-uses. For example, a customer cannot be modelled as curtailing its HVAC load in both a DLC program and a rate program during the same event. We applied a hierarchy of

demand response programs for each sector based on Tri-State's unique market position, as shown in Table 4.

**Table 4. Demand Response Programs Applied by Sector**

| RESIDENTIAL | AGRICULTURAL | COMMERCIAL | INDUSTRIAL |
|---|---|---|---|
| Smart Devices | Direct Load Control | Capacity Bidding | Capacity Bidding |
| Behavioral | Time Varying Rates | Smart Devices | Time Varying Rates |
| Direct Load Control | | Direct Load Control | |
| Time Varying Rates | | Time Varying Rates | |

#### 2.5.4. Estimate Economic DR Potential

Economic potential is a subset of technical potential that is economically cost-effective. A full cost-benefit analysis was conducted for each DR program incorporating Tri-state's avoided energy and capacity costs, program start-up costs, on-going administrative costs, equipment costs for the program and the participant, and discount rates.

Resource acquisition costs fall into one of two categories. Fixed costs include program start-up, infrastructure, maintenance, administration, and data acquisition. Variable costs include hardware costs, which vary by the number of customers, and incentive costs, which can vary by number of customers or kW reduced.

Fixed and variable costs were estimated for each program type according to comparable programs implemented by other utilities or other potential studies. In cases where published cost information could not be found, the Team used assumptions based on other comparable program data points. The Team also incorporated a multiplier of 8 into start-up costs and administration costs, to represent the complexity of managing a program with multiple co-op partners. This analysis assumes a cost of $640,000 or more to start a demand response program. Lower costs were incorporated for time-vary rates programs - $100,000 for start-up and $23,000 per year for administration. Lower costs were also assumed for some commercial programs where commercial participation could be assumed as an addition to an existing residential program. All programs were assumed to require an annual evaluation at a cost of $50,000. Average hardware, communication, and incentive levels were estimated based on published values from other utilities or studies.

Program cost assumptions are summarized in Table 5.

**Table 5. Demand Response Program Cost Assumptions**

| SECTOR | PROGRAM | START-UP | ADMIN | EVAL | MARKETING | EQUIP |
|---|---|---|---|---|---|---|
| Residential | Smart Tstat | $640k | $538k/yr | $50k/yr | $50/signup | $0 |
| | Smart Water Heater | $665k | $543k/yr | $50k/yr | $50/signup | $175 |
| | DLC Central AC | $665k | $543k/yr | $50k/yr | $50/signup | $225 |
| | DLC Room AC | $665k | $543k/yr | $50k/yr | $20/signup | $50 |
| | DLC Pool Pump | $665k | $543k/yr | $50k/yr | $20/signup | $200 |
| | CPP no tech | $100k | $23k/yr | $50k/yr | $25/signup | $200 |
| | Time of Use | $100k | $23k/yr | $50k/yr | $25/signup | $200 |
| | Behavioral | $640k | $7/meter | $50k/yr | $0 | $0 |
| Irrig-ation | DLC | $665k | $862k/yr | $50k/yr | $63/premise | $500 |
| | CPP no tech | $100k | $23k/yr | $50k/yr | $25/signup | $200 |
| | Time of Use | $100k | $23k/yr | $50k/yr | $25/signup | $200 |
| Commer-cial | Capacity Bidding | $640k | $184k/yr | $50k/yr | $50/premise | $0 |
| | Smart Tstat | $128k | $107k/yr | $50k/yr | $50/signup | $0 |
| | DLC Water Heater | $128k | $107k/yr | $50k/yr | $50/signup | $175 |
| | DLC Room AC | $665k | $543k/yr | $50k/yr | $20/signup | $50 |
| | CPP no tech | $100k | $23k/yr | $50k/yr | $25/signup | $200 |
| | Time of Use | $100k | $23k/yr | $50k/yr | $25/signup | $200 |
| Indust-rial | Capacity Bidding | $640k | $184k/yr | $50k/yr | $50/premise | $0 |
| | CPP no tech | $100k | $23k/yr | $50k/yr | $25/signup | $200 |
| | Time of Use | $100k | $23k/yr | $50k/yr | $25/signup | $200 |

### 2.5.5.Estimate Achievable DR Potential

The Team applied program participation rates to economic potential to incorporate each sector's willingness to participate in demand response programs. This participation rate is expressed as a percentage of eligible customers. As it takes some time for a utility to fully implement a demand response program, program participation rates are assumed to reach a mature participation rate after 10 years.

Combining economic potential with program and event participation rates yields "achievable potential," or the load that can reasonably be reduced during any one event for a certain program. The Team modeled two achievable potential scenarios for demand response to illustrate the impacts of varying incentive levels to drive program participation. Adoption for both scenarios were selected based on achieved participation rates from similar program types in other jurisdictions.

- 'High' scenario represents best-in-class participation for programs with non-mandantory (opt-in) enrollment
- 'Low' scenario represent more typical or 'average' participation rates from the body of similar programs.

Steady-state participation rates are summarized in Table 6 for each achievable scenario.

**Table 6. Demand Response Program Achievable Scenario Participation Rates**

| SECTOR | PROGRAM | ACHIEVABLE HIGH | ACHIEVABLE LOW |
|---|---|---|---|
| Residential | Smart Tstat | 59% | 20% |
| | Smart Water Heater | 59% | 20% |
| Irrigation | DLC | 48% | 15% |
| | CPP no tech | 18% | 8% |
| Commercial | Capacity Bidding | 20% | 10% |
| | Smart Tstat | 20% | 8% |
| | CPP no tech | 18% | 8% |
| Industrial | Capacity Bidding | 20% | 10% |
| | CPP no tech | 18% | 8% |

The results of the approach described in this section are presented in Section 9.

## 2.6. Behind-the-Meter Distributed Energy Resource Potential Assessment[8]

For the purposes of this report, distributed energy resources is defined as equipment installed at customer premises behind-the-meter that generates electricity. This study reviewed the potential for end users of Tri-State's electricity to install and operate these types of resources.

The DER potential study followed the same method as energy efficiency potential in that the DER assessment reviews the opportunity for technical, economic, and achievable potential. The analysis limited resources for this potential assessment study to technologies that are behind-the-meter and owned by the customer. The analysis did not consider market potential for supply-side resources within this assessment. The market potential assessment for DERs focused on solar photovoltaic (PV) systems across Tri-State's region for the period 2021 to 2040, because it was the most probable technology to be cost effective and applicable to Tri-State's territory. We performed review and preliminary cost screens for potential DER technologies such as combined heat and power and small wind but did not find these technologies to be applicable and/or cost-effective.

### 2.6.1. Estimate Technical DER Potential

The technical potential of a DER is the amount of energy that can be generated at a customer's site behind the meter.

Photovoltaic systems utilize solar panels, a packaged collection of photovoltaic cells, to convert sunlight into electricity. A system is constructed with multiple solar panels, a DC/AC inverter(s), a racking system to hold the panels, and electrical system interconnections. These systems are often roof-mounted and face south-west, south, and/or, south-east.

The study analyzed the potential associated with roof-mounted systems installed on residential and non-residential sector buildings. For the non-residential sector, the analysis estimated potential for ground mounted (or covered parking) systems for a few specific business types such as municipal

[8] Actual results for DER analysis are not included in this draft report pending gathering of additional information

facilities, parking enclosures, and some manufacturing facilities. The analysis also included battery storage as an additional configuration with each solar PV system type. This study did not explore the market potential associated utility-scale solar PV installations.

The approach to estimating technical potential required calculating the total square footage of suitable rooftop area within Tri-State's territory and calculating solar PV system generation based on building and regional characteristics. Technical potential is computed using Equation 3.

**Equation 3: Solar PV Technical Potential Calculation**

$$\boldsymbol{PV\ Technical\ Potential} = \boldsymbol{\Sigma}(\boldsymbol{Suitable\ Rooftop\ Square\ Footage} \times \boldsymbol{PV\ System\ Generation\ per\ Sq.Ft.})$$

The two key parameters in Equation 3 were estimated based on multiple data sources relevant to Tri-State's territory. A discussion of methods for defining these parameters follows.

The Team estimated total rooftop square footage using the forecast disaggregation analysis to characterize the existing and new residential and non-residential building stocks. The building stocks were characterized based on relevant parameters such as number of facilities, average number of floors, average premise consumption, and premise EUI by region. The Team used these parameters to estimate the total rooftop square footage for each Tri-State region.

To estimate the fraction of the total roof area that is suitable for rooftop solar PV, the Team relied on research completed by the National Renewable Energy Laboratory (NREL). NREL has developed estimates of the portion of total rooftops across the country that are suitable for solar PV based on analysis of LIDAR data. NREL criteria for suitable roof area include:

- **Contiguous rooftop area size:** Rooftops with fewer than 10 square meters of contiguous roof area excluded.
- **Rooftop orientation (tilt and azimuth):** Northeast through northwest orientation and roof pitches greater than 60 degrees excluded.
- **Shading:** Roof areas that had a minimum solar exposure of less than 80% relative to an unshaded roof were excluded.

Based on NREL's data, the Team was able to apply unique suitability factors to estimate the total square footage of suitable rooftop for residential and non-residential buildings for each Tri-State region. The Team further adjusted the total suitable rooftop square footage by accounting for existing systems. Data on existing systems was captured from Google's Project Sunroof and applied to the NREL suitability factors.

The second key parameter – PV system generation – was estimated by developing standardized solar PV system configurations. These included system sizes for residential premises ranging from 3 to 20 kW (DC) and 10 to 2,000 kW (DC) for non-residential premises. Additionally, the Team selected battery system sizes for each solar PV system size to dispatch energy for 2-4 hours during low and/or non-generation time periods.

The Team relied on NREL's PVWatts[9] (Version 6) and System Advisor Model (SAM)[10] tools to estimate system generation for both residential and non-residential sited systems. These tools model PV power density based on site specific data from NREL's LIDAR-based NSRDB to estimate total solar irradiance in conjunction with PV system specifications. The PV system simulations were generated for various cities within each Tri-State region. The Team based assumptions for PV system azimuth on rooftop orientation data sourced from Google's Project Sunroof. For the analysis the following assumptions are summarized in Table 7.

**Table 7: Key Assumptions in Solar PV Analysis**

| PARAMETER | ASSUMPTIONS |
|---|---|
| Residential System Sizes (Nominal DC Capacity) | 3 kW, 5 kW, 7.5 kW, 10 kW, 15 kW, 20 kW |
| Non-Residential System Sizes (Nominal DC Capacity) | 10 kW, 15 kW, 20 kW, 25 kW, 50 kW, 100 kW, 250 kW, 500 kW, 1,000 kW, 2,000 kW |
| System losses | 14.1% |
| Tilt | By region |
| Azimuth: | By region |
| DC to AC size ratio | 1.2 |
| Inverter efficiency | 96% (micro-inverter) |
| Battery Round-Trip Efficiency | 85% |
| Technology Useful Life | 20 years |

Based on the simulations and resulting capacity factors for residential and non-residential buildings for each Tri-State region, we applied the capacity factor to the system size and multiplied by 8,760 to estimate annual electricity generation. These system generation values were used to calculate total energy generation per square foot of rooftop and extrapolated based on the total suitable rooftop square footage to estimate overall all technical potential.

### 2.6.2. Estimate Economic DER Potential

As discussed in Section 2, economic potential represents the savings possible given full adoption of all cost-effective efficiency measures according to the Total Resource Cost (TRC) test or other commonly used tests. For the cost effectiveness analysis on solar PV, the Team set a TRC hurdle of 1.0[11]. To estimate economic potential for solar PV, we gathered pertinent data on system costs along with calculated generation benefits to use in the benefit-cost analysis which we conducted at the system measure level. The Team screened solar PV measures with an assumed program administration cost of $0.05 per kWh generated.

9 PVWatts estimates solar PV energy production and costs. Developed by the National Renewable Energy Laboratory. (NREL) *http://pvwatts.nrel.gov/*

10 SAM estimates houlry solar PV energy production and costs with more detailed inputs and outputs than PVwatts. Developed by the National Renewable Energy Laboratory. (NREL) *http:// https://sam.nrel.gov/*

11 The TRC hurdle is higher than the hurdle used for the energy efficiency study as the solar PV systems have a much more homogenous benefit-cost profile relative to the portfolio of diverse energy efficiency measures that when combined elevated the overall TRC ratio for the portfolio.

The Team relied on multiple data sources to determine the solar PV system costs for the system sizes and configurations mentioned above. We assessed system component costs based on data included in the National Renewable Energy Laboratory's (NREL) Q1 2018 Benchmarking report[12] which provided detailed cost information on modules, inverters (by technology), structural and electrical balance of system, supply chain, permitting-inspection-interconnection, marketing, overhead, and profit. We adjusted cost parameters from a national level to Tri-State region-specific values by using various market data provided by Energy Sage[13] for residential cost estimates and the Lawrence Berkeley National Laboratory Tracking the Sun[14] data for non-residential cost estimates. This analysis produced an estimated installation cost per watt installed which we applied to various system sizes to estimate total installed cost. Additionally, the Team included O&M costs that scale with system size. Finally, we assumed the impact of the federal investment tax credit (ITC) to follow the existing schedule at the time of this report which equates to a 10% tax credit for commercial systems by 2022 and a 0% tax credit for residential systems by 2022.

In addition to modeling solar PV system costs, the Team estimated cost impacts for solar PV systems coupled with battery storage. Because these systems are far less prevalent in both residential and non-residential systems at the time of reporting, fewer published data on battery costs, balance of system costs, and maintenance were available. Moreover, the battery capacity is also variable based on the service need. Ultimately, multiple data sources were used to assume an overall capital cost per kWh based on a 3- or 4-hour battery for various measure permutations. O&M costs were largely defined by a ten-year amortized battery replacement cost.

**Table 8: Average Solar PV Installation Cost**

| SECTOR | SYSTEM COST ($/ DC W)[1] |
|---|---|
| Residential | $3.22 |
| Residential (Battery) | $4.88 |
| Non-Residential (<250 kW) | $2.73 |
| Non-Residential (<250 kW w/ Battery) | $3.52 |
| Non-Residential (≥250 kW) | $1.50 |
| Non-Residential (≥250 kW w/ Battery) | $1.87 |
| Operations & Maintenance | $10-$15/kw/yr |
| Operations & Maintenance w/Battery | $24-$76/kw/yr |

[1]Costs reflect impact of federal investment tax credit and are averages across regions. Analysis uses region-specific costs.

[12] Fu, R, et. al., U.S. Solar Photovoltaic System Cost Benchmark: Q1 2018. NREL, November 2018.

[13] Energysage Solar Marketplace Intel Report, H2 2018 – H1 2019.

[14] Barbose, G. and Darghouth, N., Tracking the Sun. Lawrence Berkeley National Laboratory. October 2019.

#### 2.6.3. Estimate Achievable DER Potential

The approach to assessing achievable potential for solar PV follows the same logic and methods as outlined in Section 0. Similar to the energy efficiency analysis, the Team defined adoption curves based on a Bass diffusion model. The data informing the adoption curves were based on two key parameter inputs:

- Maximum estimated number of buildings suitable for solar
- Adoption rates based on customer willingness to participate

The Team estimated the first parameter based on the count of buildings suitable for solar PV measures. For example, if a 7.5 kW solar PV measure passed cost effectiveness, the total count of applicable buildings is defined as residential buildings that do not consume more than the total annual generation of the PV system and have sufficient rooftop area to support a system of that size. The second parameter of customer adoption is based on secondary data collected from the Midwest that surveyed residential and non-residential customers' willingness to install solar PV on their home or facility with varying incentive levels. Residential customers were asked their willingness to install based rebate values that covered a percent of the total system cost while non-residential customers were asked their willingness to install based on number of years of payback. With these parameters defined, the Team developed Bass diffusion curves to approximate adoption at various incentive levels. Innovation and imitation coefficients were defined based on state-specific research conducted by NREL[15].

# 3. MARKET CHARACTERIZATION & BASELINE FORECAST FINDINGS

## 3.1. Overview

As outlined in Section 2, the analysis of theoretically achievable savings potential requires an accurate characterization of the baseline energy usage and customer characterization. This section summarizes the market and end-use characterization including Tri-State's energy usage by sector, region, and end-use. Tri-State's 2018 electricity sales to member cooperative customers were found to be 14,974 GWh with distribution of sales by customer sector shown in Figure 5, sales by region in Figure 6, and finally with detail conjoined by customer sector and region included in Figure 7.

[15] Sigrin, B, et. al. The Distributed Generation Market Demand Model (dGen): Documentation. National Renewable Energy Laboratory. February 2016.

**Figure 5. 2018 Energy Sales by Customer Sector**

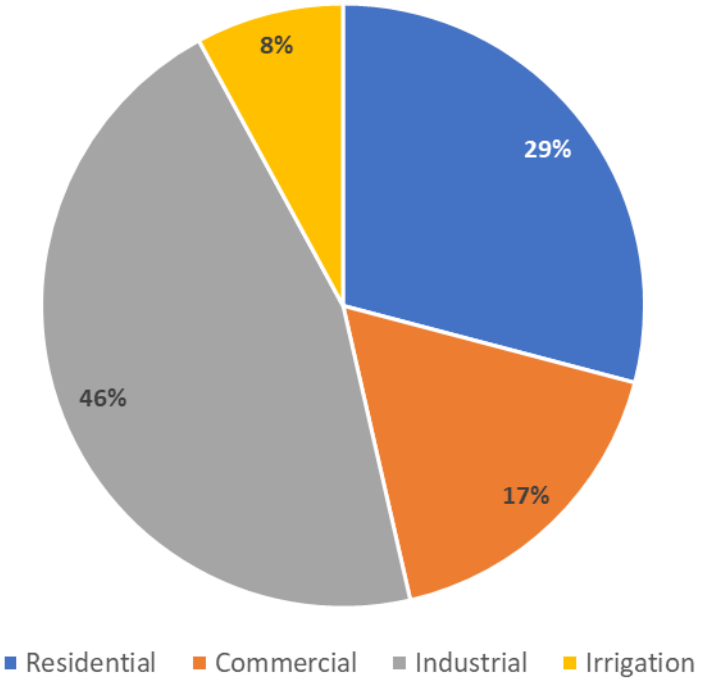


**Figure 6. 2018 Energy Sales by Region**

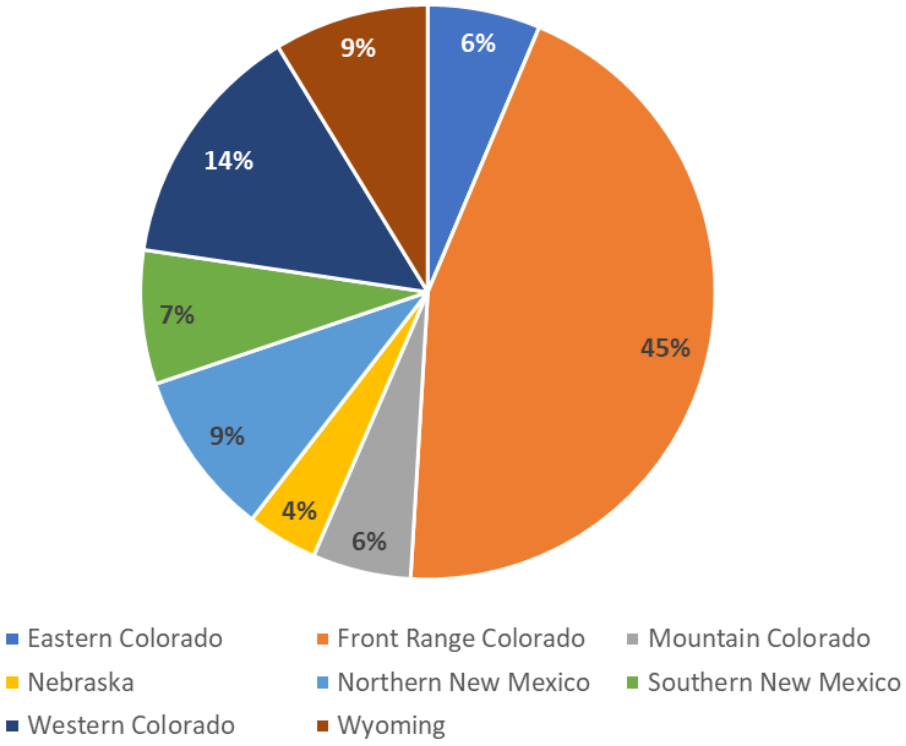
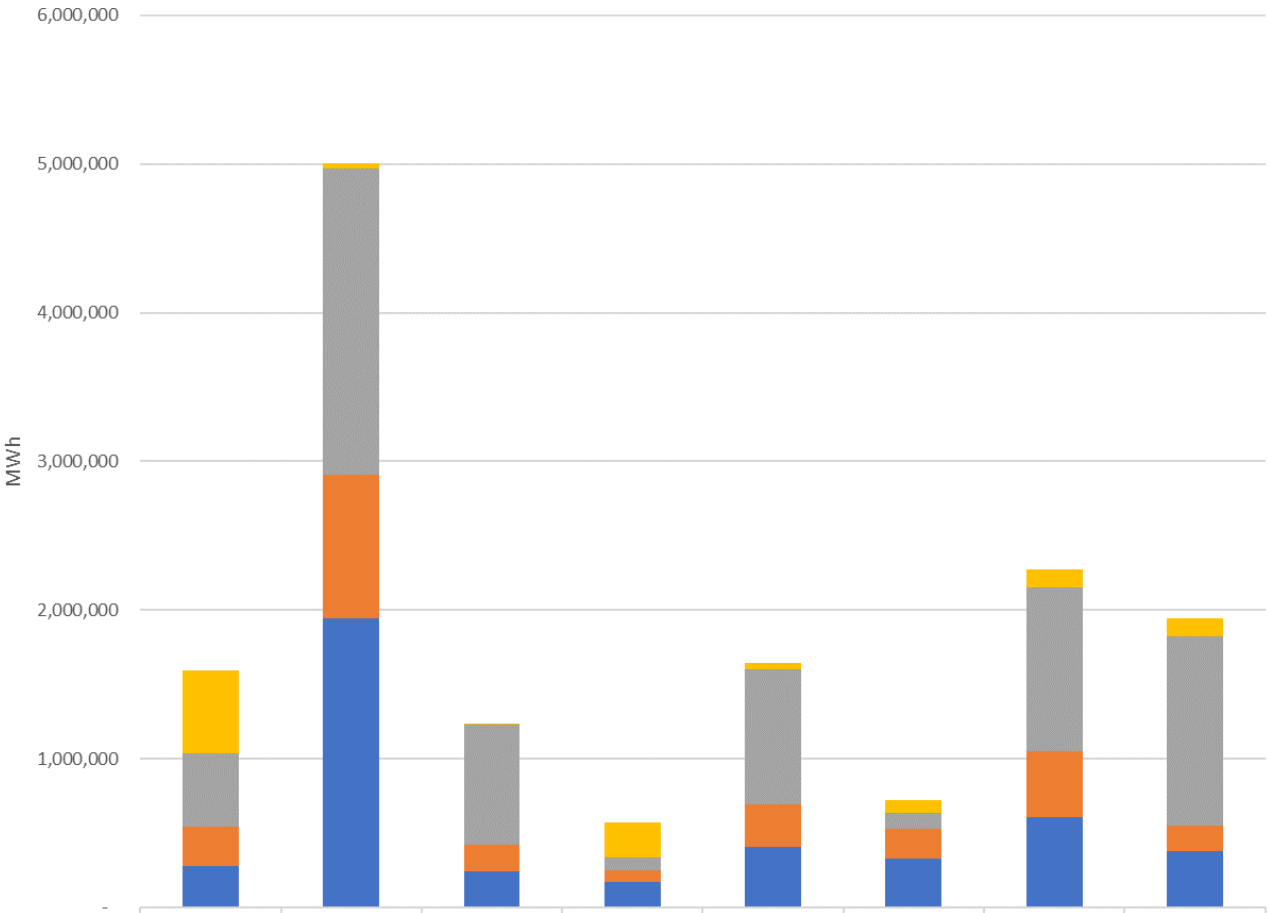


**Figure 7. 2018 Energy Sales by Customer Sector and Region**



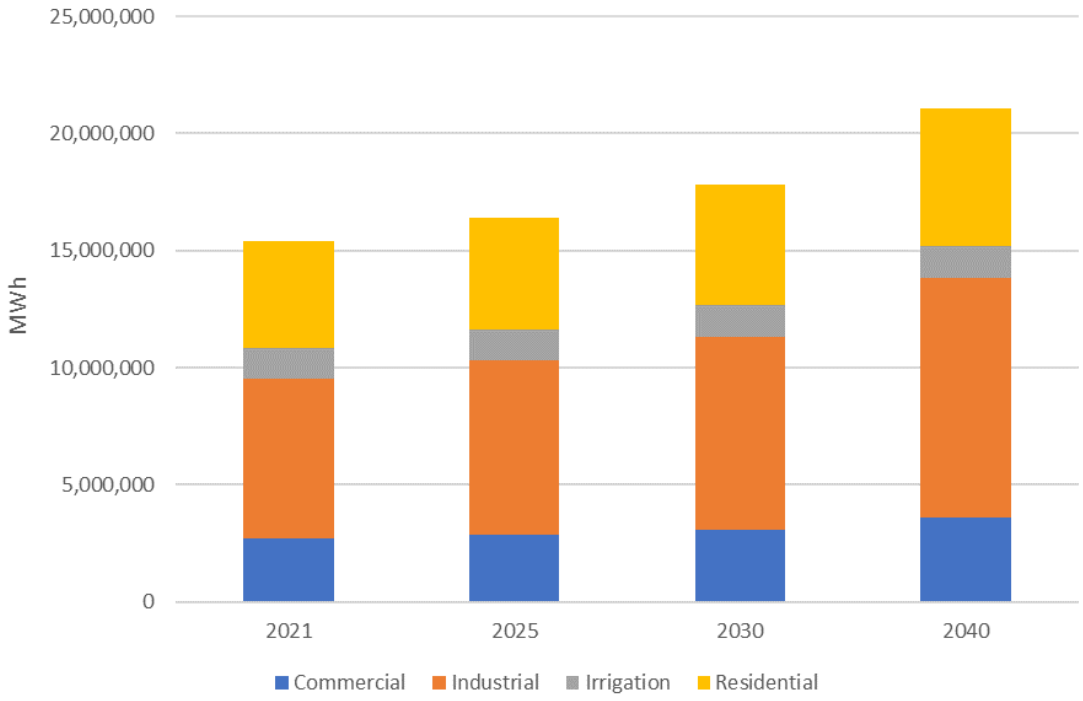

| | Eastern Colorado | Front Range Colorado | Mountain Colorado | Nebraska | Northern New Mexico | Southern New Mexico | Western Colorado | Wyoming |
|---|---|---|---|---|---|---|---|---|
| Irrigation | 554,724 | 31,967 | 861 | 237,972 | 41,763 | 85,091 | 116,352 | 119,890 |
| Industrial | 494,719 | 2,061,346 | 814,705 | 79,803 | 903,438 | 107,893 | 1,104,101 | 1,268,084 |
| Commercial | 268,177 | 964,547 | 176,453 | 78,733 | 289,986 | 197,934 | 444,417 | 173,590 |
| Residential | 276,257 | 1,944,118 | 241,514 | 173,762 | 406,734 | 328,318 | 606,582 | 380,071 |

The industrial sector comprises a very large share of the energy load (46%). Energy use in this sector is predominately focused around the oil, gas, and mining industries, as described further in section 4.3. Conversely, the commercial sector share, at 17%, is lower than other electric utilities that serve metropolitan communities and typically have a commercial sector share closer to 40 to 50% of all energy sales. Tri-State's relatively low commercial sector values reflect the fact that many of the member cooperatives do not serve the city and town customers within their service territories. Municipal electric utilities are common for many rural towns within western Nebraska, eastern Colorado, and most of Wyoming. Eastern Colorado and Nebraska regions have significant shares of their overall electricity sales in the irrigation sector.

Figure 8 presents the baseline load forecast at key milestone points during the analysis period. The industrial sector will see the largest amount of load growth, increasing by approximately 50% by 2040.

Commercial and residential sector load will each increase by approximately one-third. The load growth estimate for the irrigation sector is negligible.

**Figure 8. Baseline Load Forecast by Sector by Milestone Year**

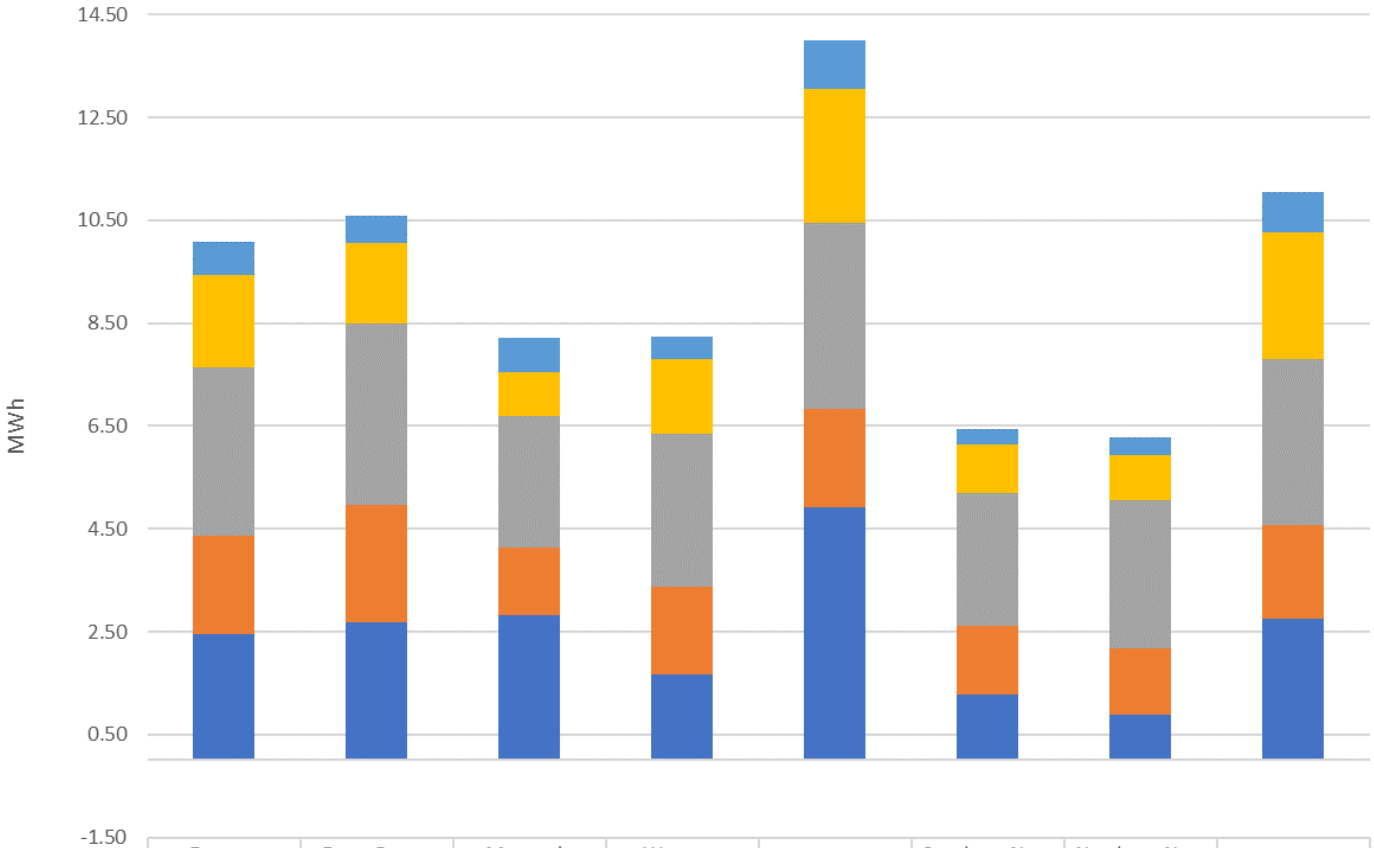



## 3.2. Residential End-Uses and Loads

The residential sector is responsible for 4,357 GWh of electric consumption, includes approximately 470,000 unique residential dwellings and accounts for 29% of Tri-State's total electricity sales. Average per dwelling energy usage was in line with an annual consumption of 9,260 kWh per home. Based on the limited information available to segment single-family, multi-family, and/or manufactured homes energy use or equipment saturations, it was determined that the existing residential sector should be analyzed in its entirety with no sub-sectors analyzed.

There are notable variations in average home size, average annual energy consumption, and equipment saturations across the different regions as shown in Figure 9.

**Figure 9. Average Annual End-Use Consumption per Residence by Region (2018)**




| | Eastern Colorado | Front Range Colorado | Mountain Colorado | Western Colorado | Nebraska | Southern New Mexico | Northern New Mexico | Wyoming |
|---|---|---|---|---|---|---|---|---|
| Water Heat | 653 | 540 | 668 | 444 | 955 | 298 | 334 | 785 |
| Plug Load | 1,786 | 1,569 | 865 | 1,441 | 2,590 | 948 | 887 | 2,478 |
| Appliances | 3,279 | 3,527 | 2,557 | 2,972 | 3,621 | 2,564 | 2,868 | 3,225 |
| Lighting | 1,919 | 2,280 | 1,308 | 1,718 | 1,909 | 1,356 | 1,290 | 1,810 |
| HVAC | 2,443 | 2,674 | 2,818 | 1,662 | 4,928 | 1,269 | 890 | 2,757 |

The Team utilized the 2012 Tri-State residential end-use survey to compile end-use saturations and average residential premise square footage as in Table 9.

**Table 9: Tri-State End-Use Saturations per Region**

| END-USE | EASTERN COLORADO | FRONT RANGE COLORADO | MOUNTAIN COLORADO | WESTERN COLORADO | NEBRASKA | SOUTHERN NEW MEXICO | NORTHERN NEW MEXICO | WYOMING |
|---|---|---|---|---|---|---|---|---|
| **Central Heating** | 13.2% | 16.0% | 22.7% | 15.6% | 25.5% | 8.4% | 6.3% | 15.4% |
| **HVAC Aux** | 67.9% | 91.7% | 78.3% | 78.6% | 72.6% | 57.5% | 39.4% | 71.8% |
| **Room AC** | 18.1% | 6.9% | 1.8% | 5.8% | 23.3% | 11.3% | 11.8% | 16.1% |
| **Evap Cooler** | 12.2% | 10.2% | 1.6% | 17.3% | 10.2% | 33.4% | 10.2% | 12.2% |
| **Central Air** | 44.8% | 49.9% | 1.4% | 7.4% | 44.6% | 19.7% | 12.5% | 26.3% |
| **Heat Pump** | 4.2% | 3.9% | 0.2% | 1.2% | 14.4% | 2.6% | 2.6% | 2.0% |
| **Interior Lighting** | 100.0% | 100.0% | 100.0% | 100.0% | 100.0% | 100.0% | 100.0% | 100.0% |
| **Exterior Lighting** | 100.0% | 100.0% | 100.0% | 100.0% | 100.0% | 100.0% | 100.0% | 100.0% |
| **Electric Cooking** | 56.4% | 70.2% | 65.8% | 54.1% | 71.3% | 38.8% | 71.0% | 64.6% |
| **Washer** | 81.1% | 94.0% | 79.8% | 89.5% | 89.6% | 82.3% | 76.8% | 86.2% |
| **Electric Dryer** | 75.3% | 83.7% | 67.5% | 69.5% | 85.6% | 67.7% | 61.3% | 80.8% |
| **Dish Washer** | 67.9% | 91.7% | 78.3% | 78.6% | 72.6% | 57.5% | 39.4% | 71.8% |
| **Electric Water Heater** | 29.7% | 20.3% | 40.9% | 31.4% | 53.7% | 25.7% | 25.8% | 44.7% |
| **Refrigerator** | 84.5% | 96.1% | 93.3% | 94.3% | 91.1% | 90.6% | 91.5% | 89.1% |
| **Second Refrig** | 23.4% | 24.5% | 14.1% | 14.8% | 27.5% | 16.6% | 14.6% | 21.8% |
| **Freezer** | 69.1% | 62.6% | 40.6% | 54.3% | 77.0% | 53.6% | 58.5% | 72.0% |
| **Exterior Plug Loads** | 100.0% | 100.0% | 100.0% | 100.0% | 100.0% | 100.0% | 100.0% | 100.0% |
| **Plug Loads** | 100.0% | 100.0% | 100.0% | 100.0% | 100.0% | 100.0% | 100.0% | 100.0% |

The saturations of 'plug loads' and 'lighting' are both 100% by definition. Therefore, the contribution of these end-uses to the overall energy usage is driven by the unit energy consumption (UEC) and by the prevalence of certain equipment within the end-use category.

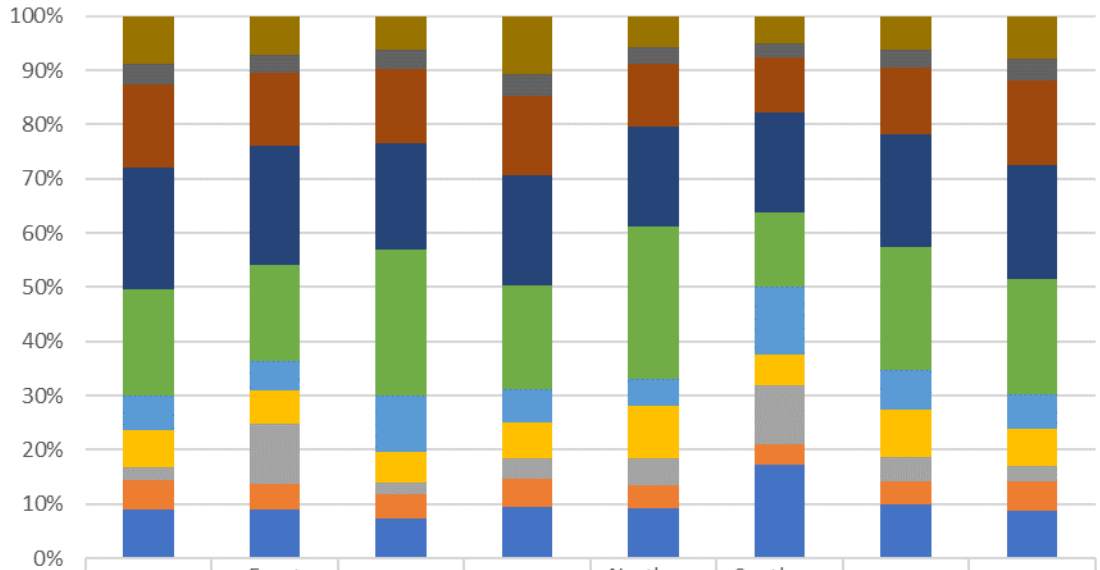
The analysis finds lower appliance saturations and smaller premise square footage for the New Mexico region residences. As expected, there is a higher prevalence of electric space and water heating in the colder climates of mountain Colorado, Nebraska, and Wyoming due to the lack of available natural gas in the rural environment.

## 3.3. Commercial End-Uses and Loads

The commercial sector is responsible for 2,594 GWh of electric consumption, which accounts for 17% of Tri-State's total electricity sales. In general, the commercial sector covers a large spectrum of customers, usually smaller in size as compared to the remainder of the non-residential customers, with 71% having a peak demand less than 250 kW.

Since the Team only had business type data for large commercial/industrial customers over 250KW, an analysis step was to segment the remainder of customers into distinct commercial business types. Assumptions largely based on secondary data used in this segmentation analysis were checked in the load calibration analysis of the end-use profile.

**Figure 10. Commercial Sector Energy Shares by Business Segment and Region (2018)**



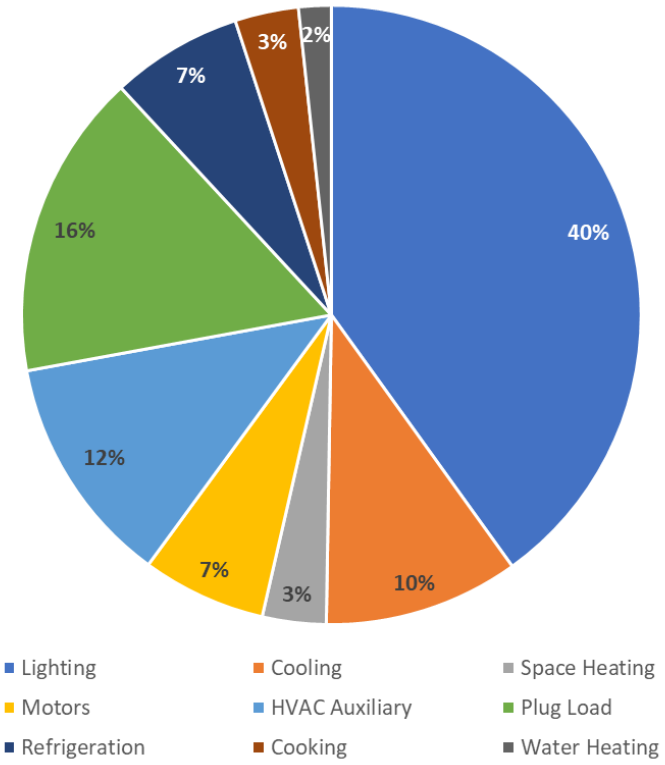

| | Eastern Colorado | Front Range Colorado | Mountain Colorado | Nebraska | Northern New Mexico | Southern New Mexico | Western Colorado | Wyoming |
|---|---|---|---|---|---|---|---|---|
| Warehouse | 9% | 7% | 6% | 11% | 6% | 5% | 6% | 8% |
| Restaurant | 4% | 3% | 3% | 4% | 3% | 3% | 3% | 4% |
| Office | 15% | 13% | 14% | 15% | 12% | 10% | 12% | 15% |
| Retail | 22% | 22% | 20% | 20% | 18% | 18% | 21% | 21% |
| Miscellaneous | 20% | 18% | 27% | 19% | 28% | 14% | 23% | 21% |
| Lodging | 6% | 6% | 10% | 6% | 5% | 13% | 7% | 6% |
| Health | 7% | 6% | 6% | 7% | 10% | 5% | 9% | 7% |
| Government | 2% | 11% | 2% | 4% | 5% | 11% | 4% | 3% |
| Grocery | 5% | 5% | 5% | 5% | 4% | 4% | 4% | 6% |
| Education | 9% | 9% | 7% | 9% | 9% | 17% | 10% | 9% |

The Team next identified the appropriate energy usage intensity (EUI), or end-use energy consumption per square foot, for each end-use studied. These EUIs were calculated based on other applicable

regional commercial end-use studies, such as those found in Wyoming, Montana, Utah, Colorado, New Mexico, and Iowa. Figure 11 summarizes the energy consumption for each end-use.

Lighting makes up forty-five percent of the total electricity consumption, which is attributable to the fact that this end-use is common in all sub-sectors and does not have any seasonal operation. Lighting is followed by HVAC Auxiliary which included fans, pumps, motors, and electronics used to move or control HVAC air and water systems.

**Figure 11. Commercial Energy End-Use Consumption Shares**

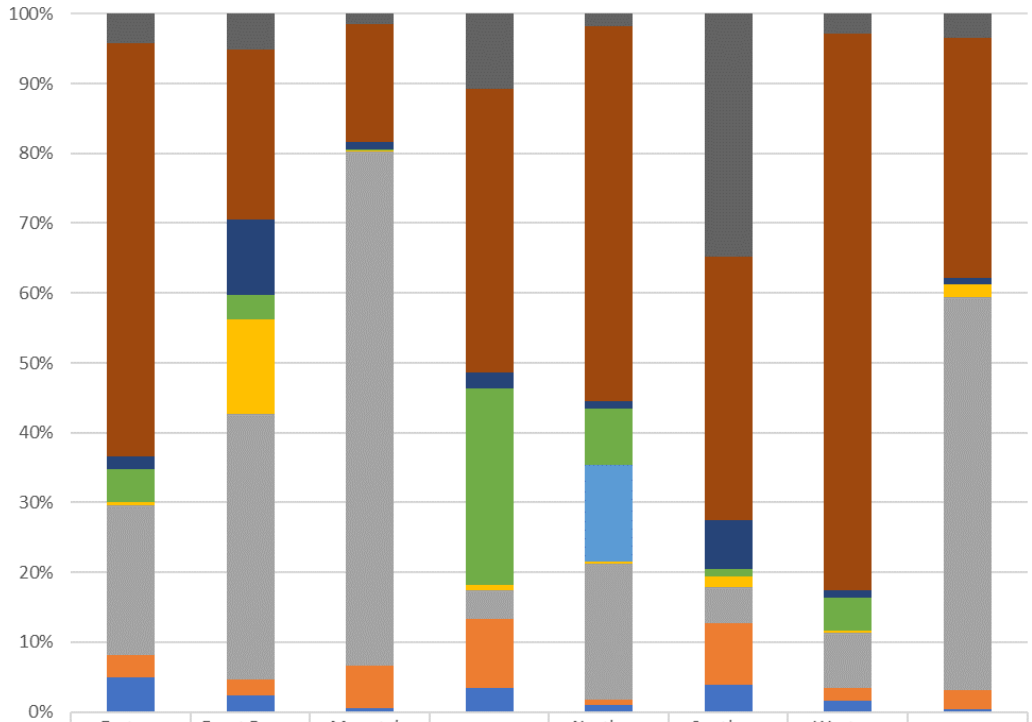



## 3.4. Industrial End-Uses and Loads

Industrial is the largest sector, accounting for 6,834 GWh of electric consumption and 46% of Tri-State's total electricity sales. In general, Tri-State's industrial sector is unique since approximately 77% of the sector's consumption is from the oil and gas industry and less than 15% is from manufacturing industries (Figure 12).

Since the Team only had business type data for large commercial/industrial customers over 250KW, an analysis step was to segment the remainder of customers into distinct industrial business types. Assumptions used in this segmentation analysis were checked in the load calibration analysis of the end-use profile.

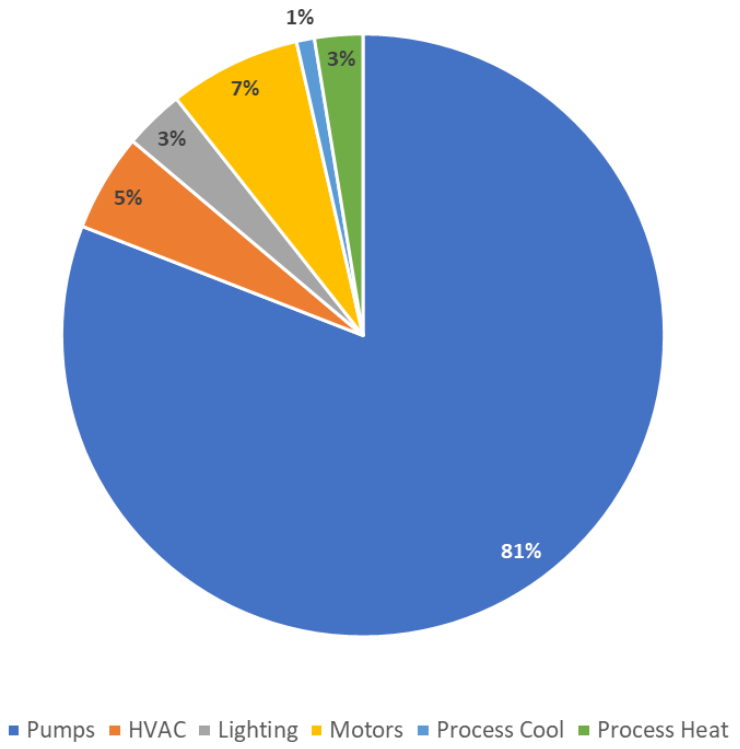
**Figure 12. Industrial Sector Energy Shares by Business Segment and Region (2018)**




| | Eastern Colorado | Front Range Colorado | Mountain Colorado | Nebraska | Northern New Mexico | Southern New Mexico | Western Colorado | Wyoming |
|---|---|---|---|---|---|---|---|---|
| TCU | 4% | 5% | 1% | 11% | 2% | 35% | 3% | 4% |
| Pipeline Transportation | 59% | 24% | 17% | 41% | 54% | 38% | 80% | 34% |
| Mfg - Misc. | 2% | 11% | 1% | 2% | 1% | 7% | 1% | 1% |
| Mfg - Chemical | 5% | 3% | 0% | 28% | 8% | 1% | 5% | 0% |
| Mfg - Paper | 0% | 0% | 0% | 0% | 14% | 0% | 0% | 0% |
| Mfg - Nonmetallic Mineral Product | 0% | 13% | 0% | 1% | 0% | 2% | 0% | 2% |
| Liquid Mining (Oil, Gas, and Carbon Dioxide) | 22% | 38% | 74% | 4% | 19% | 5% | 8% | 56% |
| Mining | 3% | 2% | 6% | 10% | 1% | 9% | 2% | 3% |
| Agriculture | 5% | 2% | 1% | 3% | 1% | 4% | 2% | 0% |

The Team identified the appropriate energy usage fraction for each industrial end-use studied. These energy end-use shares were calculated based on other applicable regional and national industrial end-use studies (Figure 13).

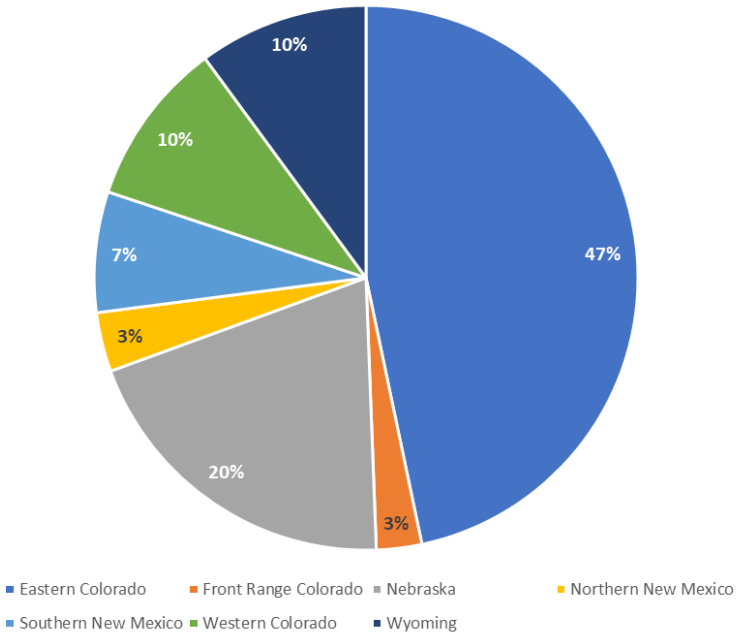
**Figure 13. Industrial Sector Energy Shares by End-Use**




## 3.5. Irrigation End-Uses and Loads

Figure 14 summarizes the irrigation energy consumption share for each region analyzed. Eastern Colorado has the largest share of irrigation energy consumption by a wide margin and is followed by the Nebraska region. The Mountain Colorado region has a negligible market share of irrigation sales and is not shown for clarity.

**Figure 14: Irrigation Energy Shares by Region**




Irrigation energy usage is entirely attributable to electric motors. These motors serve several different purposes, including well lift pumps, supplemental pressure boost pumps, drive motors for center pivots, and gate motors. Based on the Team's experience and research, it was determined that the major application for irrigation electricity is well lift pumps and supplemental pressure boost pumps; consequently, analyses and measures were developed for these end-uses.

## 3.6. Peak Demand Characterization

This section summarizes the market and end-use characterization of Tri-State's summer peak demand by sector and region. Tri-State's 2018 coincident peak demand used by member cooperatives was 2,887 MW, observed during the month of July. Figure 15 shows the distribution of the coincident peak demand by region. Energy sales by sector were used to estimate coincident peak demand allocation by sector, as described in Section 3. Figure 16 shows the results of this estimation for the Tri-State system as a whole and Figure 17 presents results by region. Notable contributors to the coincident peak demand are the residential and industrial sectors in the Front Range region, as well as the irrigation sector in Eastern Colorado and Nebraska.

**Figure 15. 2018 Coincident Peak Demand by Region**

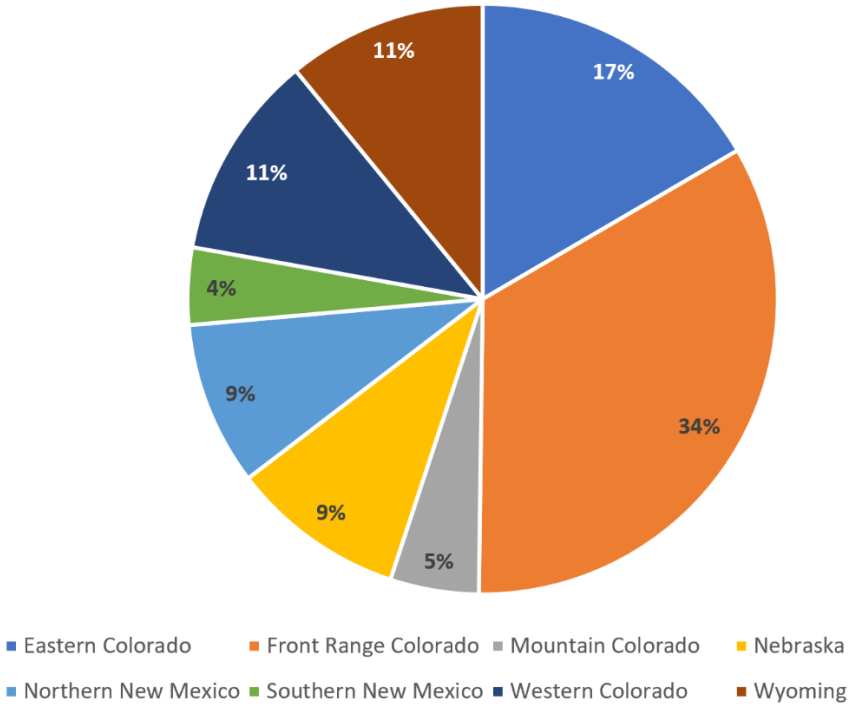



**Figure 16. 2018 Coincident Peak Demand by Sector**

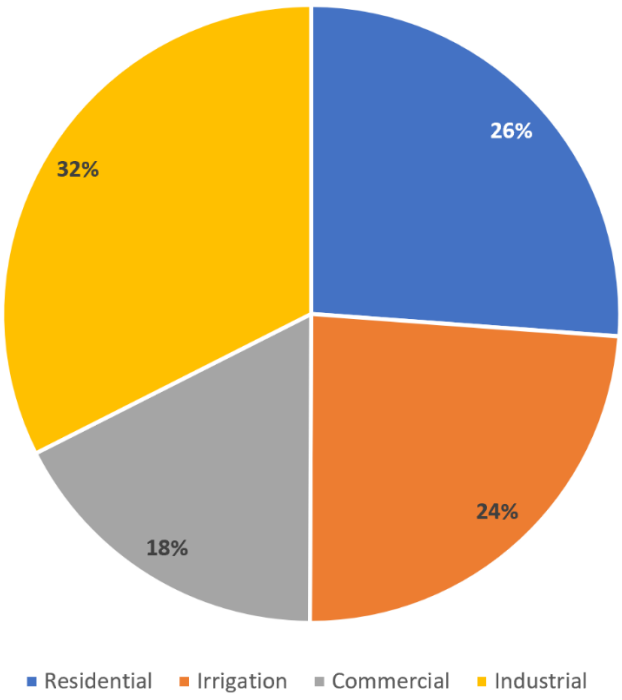
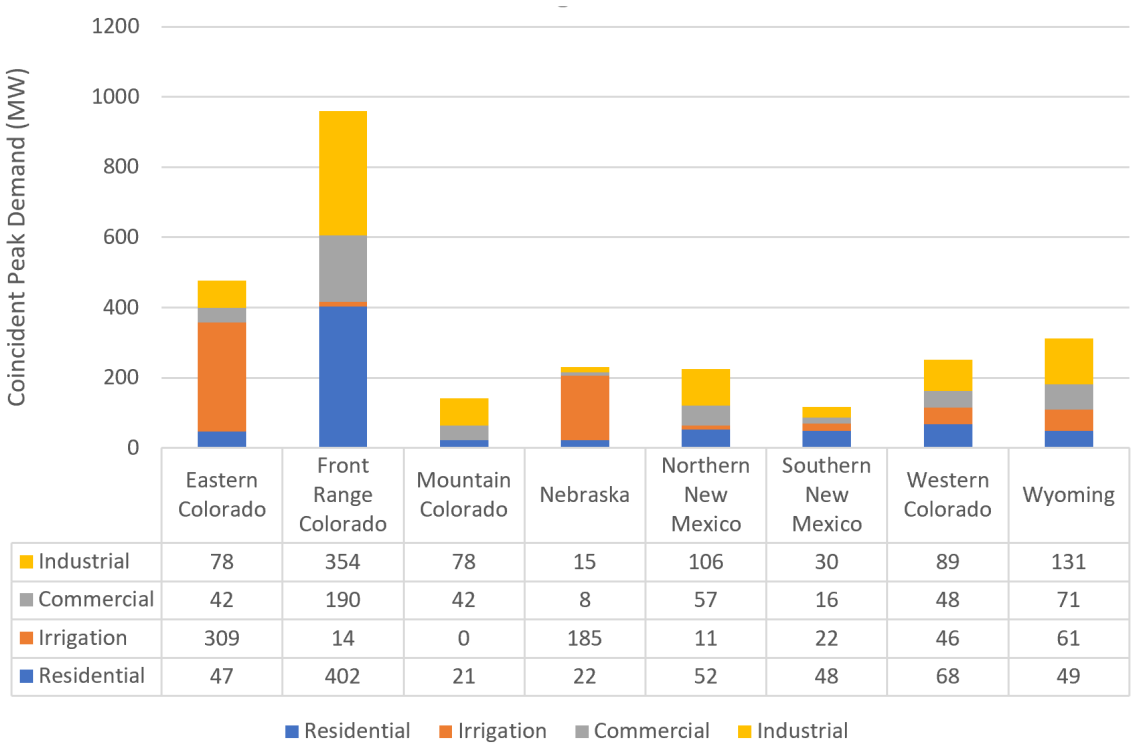


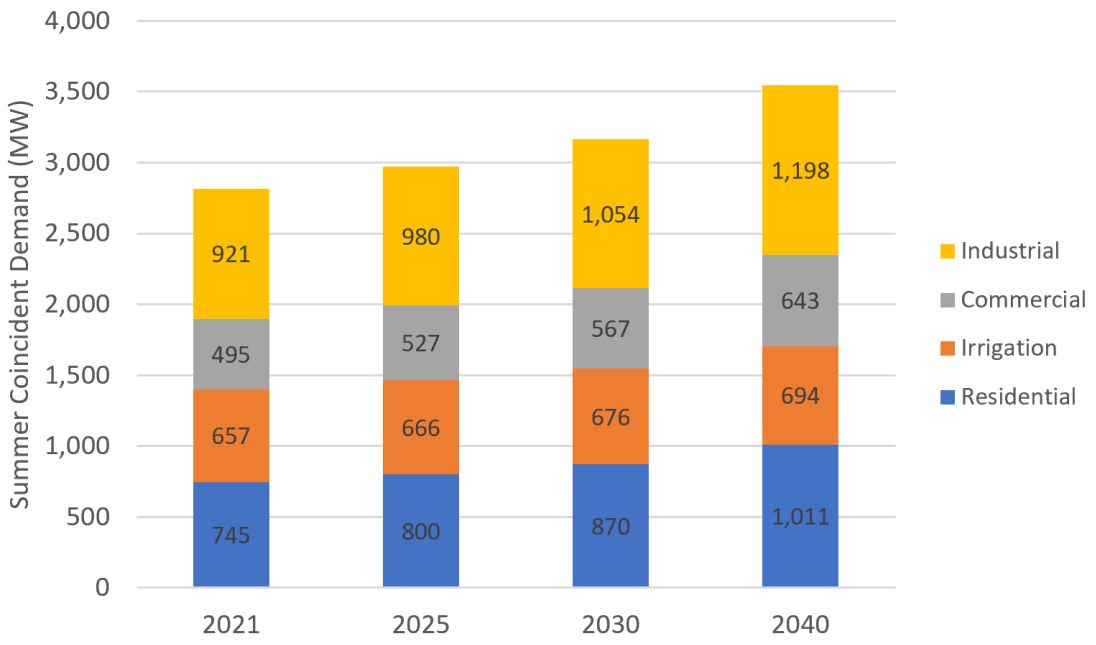
**Figure 17. 2018 Coincident Peak Demand by Sector and Region**




| | Eastern Colorado | Front Range Colorado | Mountain Colorado | Nebraska | Northern New Mexico | Southern New Mexico | Western Colorado | Wyoming |
|---|---|---|---|---|---|---|---|---|
| Industrial | 78 | 354 | 78 | 15 | 106 | 30 | 89 | 131 |
| Commercial | 42 | 190 | 42 | 8 | 57 | 16 | 48 | 71 |
| Irrigation | 309 | 14 | 0 | 185 | 11 | 22 | 46 | 61 |
| Residential | 47 | 402 | 21 | 22 | 52 | 48 | 68 | 49 |

Figure 18 presents the baseline demand forecast at key milestone points during the analysis period. Industrial, commercial, and residential sectors will increase by about 30%. The irrigation sector's coincident peak is not expected to increase significantly.

**Figure 18. Baseline Demand Forecast by Sector by Milestone Year**




# 4. PORTFOLIO LEVEL ENERGY EFFICIENCY POTENTIAL

## 4.1. Overview

The analysis finds that at the portfolio level Tri-State can achieve an average annual savings of 115 GWh from a collection of energy efficiency measures at an average annual cost of $24.3 million during the 20-year time horizon. This includes incentives and administrative costs and equates to an acquisition cost of $0.22/kWh which is in line with industry benchmarks.

## 4.2. Detailed Results

Table 10 presents portfolio-level energy efficiency savings potential by time horizon and Figure 19 shows the growth in cumulative savings potential through 2040. The Achievable-Moderate scenario estimates 38,083 MWh of savings potential in 2021 rising to 1,718,357 MWh of cumulative savings potential through 2040. Pursuing an aggressive incentive approach (Achievable-Aggressive) could increase cumulative savings potential by approximately 40%. The maximum achievable scenario increases savings potential by approximately 25% over the aggressive scenario, resulting in cumulative savings of approximately 2,876,487 GWh. First-year savings potential for the Achievable-Moderate scenario represents an increase of approximately 19% over Tri-State's 2018 energy efficiency program performance.

**Table 10 Cumulative Savings Potential (MWh) by Scenario by Time Horizon**

| MILESTONE YEAR | TECHNICAL | ECONOMIC | ACHIEVABLE MAX | ACHIEVABLE AGG | ACHIEVABLE MOD | ACHIEVABLE LOW |
|---|---|---|---|---|---|---|
| 2021 | 130,384 | 98,221 | 75,523 | 55,330 | 38,083 | 27,043 |

| | | | | | | |
|---|---|---|---|---|---|---|
| 2025 | 1,293,033 | 928,122 | 539,750 | 393,656 | 266,309 | 179,222 |
| 2030 | 3,868,940 | 2,851,171 | 1,372,971 | 1,062,225 | 723,605 | 475,993 |
| 2040 | 9,081,432 | 6,956,507 | 2,876,487 | 2,354,365 | 1,718,357 | 1,193,109 |

**Figure 19. Portfolio Energy Efficiency Savings Potential by Scenario by Year**

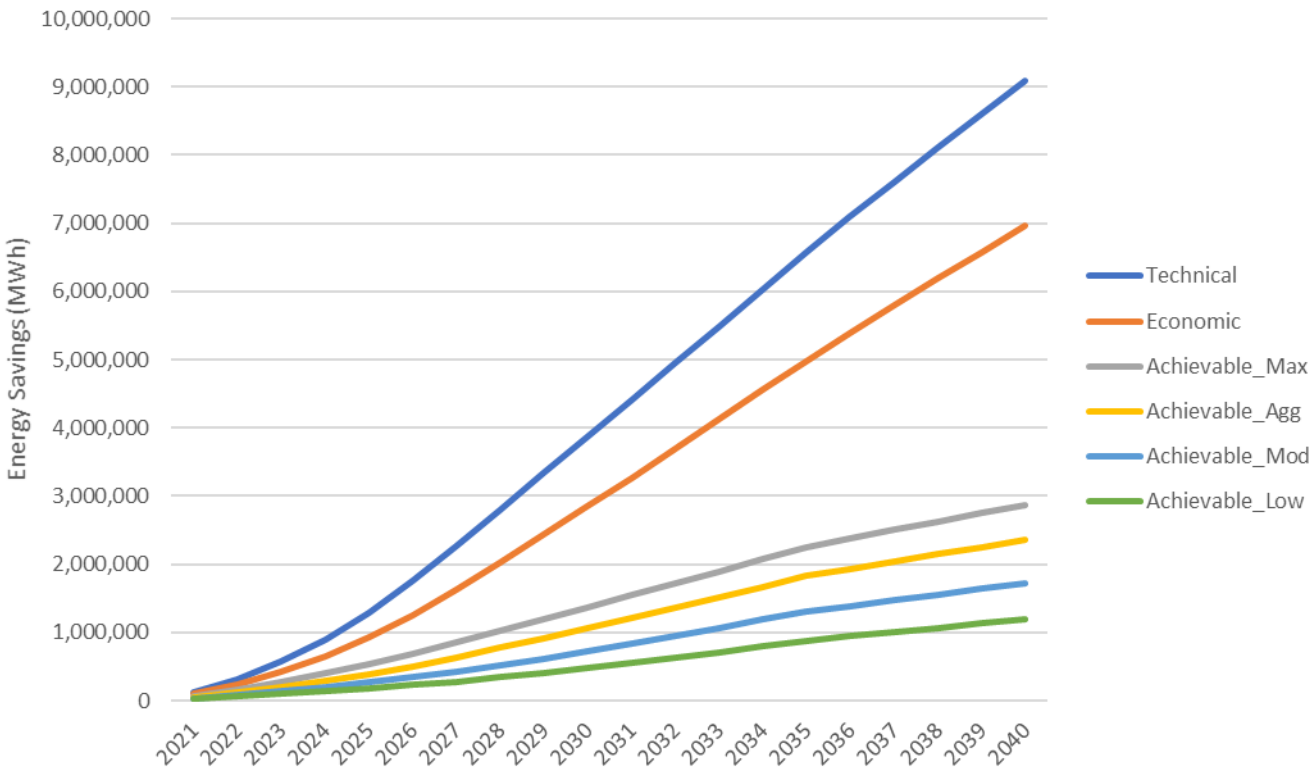



Table 11. shows the impacts of cumulative savings potential on Tri-State's baseline energy consumption forecast. The cumulative savings associated with the Achievable Moderate scenario would decrease Tri-State's baseline forecast consumption by approximately 0.25% in 2021. The reduction in baseline energy consumption would grow to 1.62% by 2025 and ultimately 8% through 2040. The range of potential reduction in baseline consumption across the achievable scenarios spans from 5.7% (Achievable-Low) to 13.7% (Achievable-Max) by 2040.

**Table 11. Portfolio Cumulative Savings Potential as % of Baseline Forecast by Sector by Year**

| MILESTONE YEAR | TECHNICAL | ECONOMIC | ACHIEVABLE MAX | ACHIEVABLE AGG | ACHIEVABLE MOD | ACHIEVABLE LOW |
|---|---|---|---|---|---|---|
| 2021 (first year) | 0.85% | 0.64% | 0.49% | 0.36% | 0.25% | 0.18% |
| 2025 | 7.88% | 5.65% | 3.29% | 2.40% | 1.62% | 1.09% |

| | | | | | | |
|---|---|---|---|---|---|---|
| 2030 | 21.74% | 16.02% | 7.71% | 5.97% | 4.07% | 2.67% |
| 2040 | 43.14% | 33.04% | 13.66% | 11.18% | 8.16% | 5.67% |

Figure 20 shows the impact of the modeled scenarios on the baseline forecast. The Achievable-Max scenario would reduce Tri-State's overall load growth significantly, though Tri-State's load will continue a steady growth trajectory under all Achievable scenarios.

**Figure 20. Impact of Portfolio Energy Efficiency Savings on Baseline Forecast by Scenario by Year**

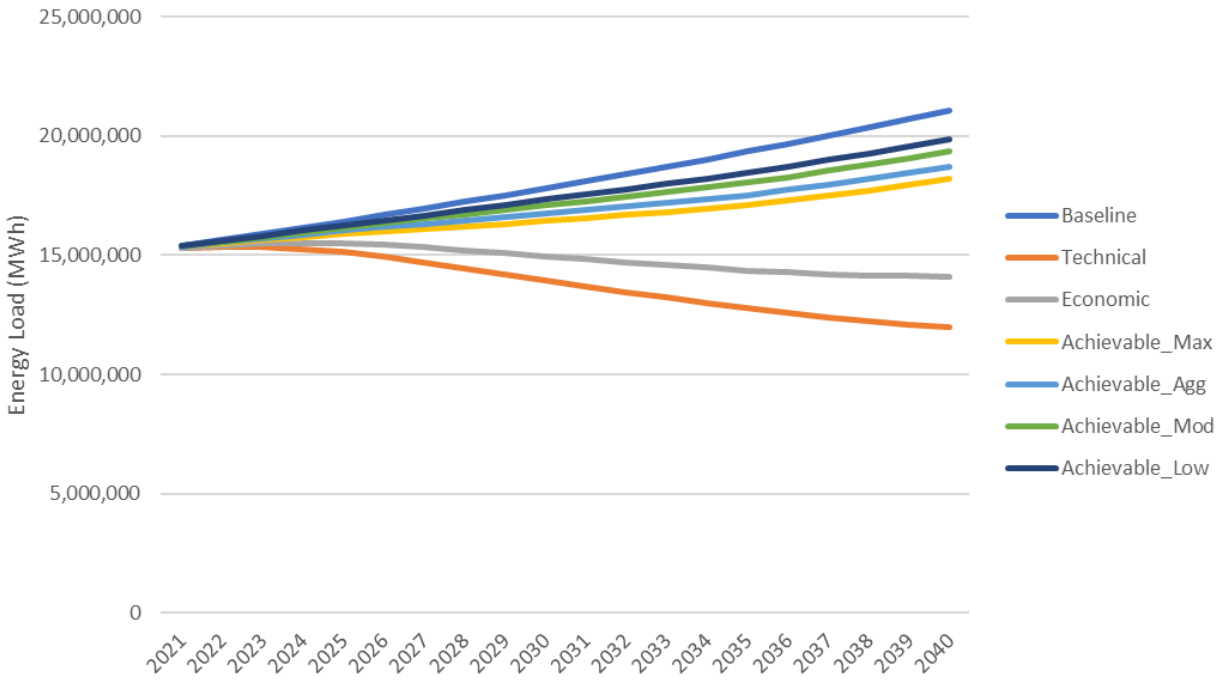
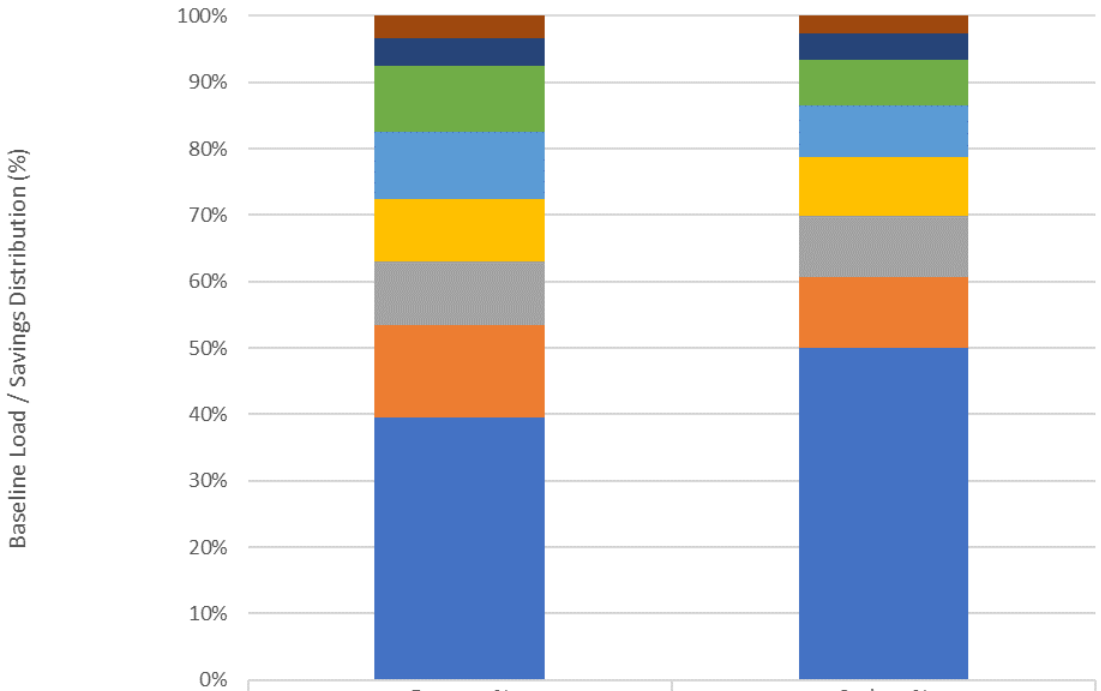



Figure 21 and Table 12 present energy savings potential by region. Front Range Colorado represents the largest share making up half the total. The other regions within Colorado account for nearly one quarter of the remaining savings potential. The two regions within New Mexico together comprise approximately 13% of total savings potential, while Wyoming accounts for approximately 10% of the total. Nebraska's savings potential is much smaller at just 2.7% of the total. This savings potential is generally aligned with the distribution of forecast energy load by region. However, Front Range Colorado's share of energy savings (50%) is larger than its share of forecast baseline energy consumption (39.5%) by a notable margin.

**Figure 21. Baseline Forecast and Portfolio Energy Efficiency Savings by Region**



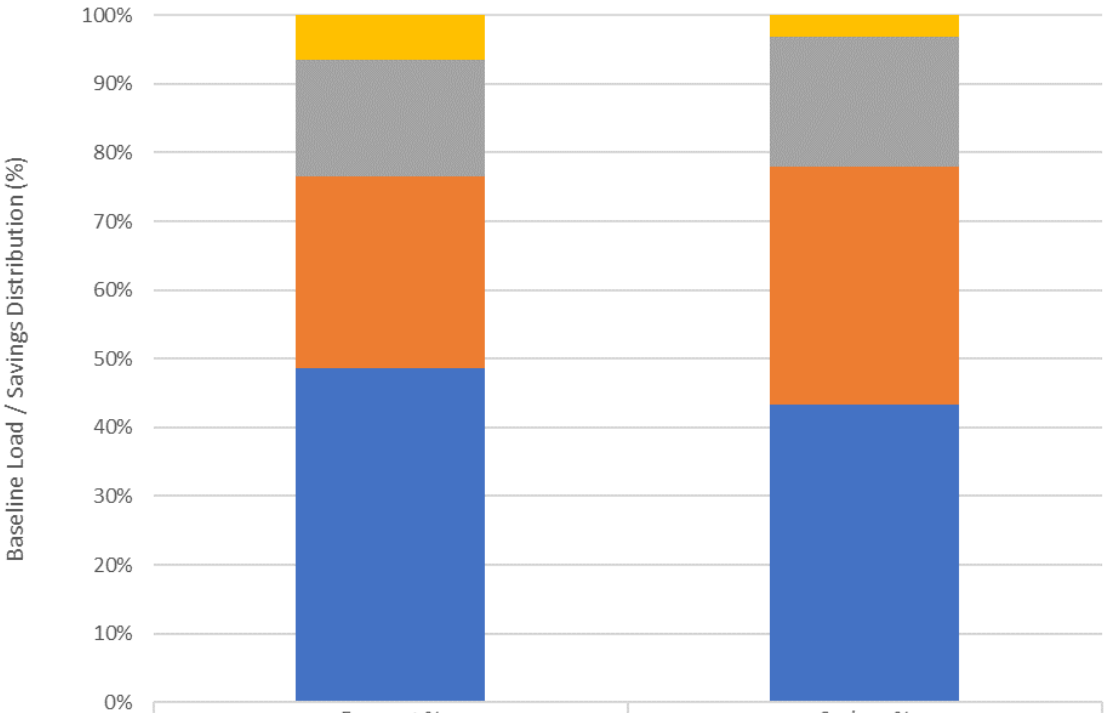

| | Forecast % | Savings % |
|---|---|---|
| Nebraska | 3.4% | 2.7% |
| Southern New Mexico | 4.1% | 3.9% |
| Mountain Colorado | 9.8% | 6.8% |
| Eastern Colorado | 10.2% | 7.8% |
| Northern New Mexico | 9.5% | 8.8% |
| Western Colorado | 9.6% | 9.2% |
| Wyoming | 13.9% | 10.6% |
| Front Range Colorado | 39.5% | 50.0% |

**Table 12. Cumulative Savings Potential by Region, Achievable-Moderate Scenario (2040)**

| STATE / SUB-REGION | POTENTIAL SAVINGS (MWH) |
|---|---|
| Colorado | 1,270,405 |
| *Front Range* | *860,016* |
| *Western* | *158,539* |
| *Mountain* | *117,559* |
| *Eastern* | *134,292* |
| Wyoming | 182,708 |
| New Mexico | 218,977 |
| *Northern* | *151,292* |
| *Southern* | *67,685* |
| Nebraska | 46,267 |
| **Total** | **1,718,357** |

As shown in Figure 22 the industrial and residential sectors represent the largest opportunity for savings. The industrial sector comprises 43% of the total savings potential and its share of the baseline forecast consumption is slightly higher at 49%. This sector's oil and gas-related energy consumption is exceptionally high, and motor-related efficiency improvements can go a long way toward reducing that load, as discussed further in Section 7. The residential sector makes up 35% of the total savings potential, and a slightly smaller portion of the baseline forecast consumption at 28%. Numerous measures are available to reduce residential energy load, with the most substantial savings coming from lighting and central heating, as discussed further in Section 5. The commercial sector also holds substantial potential energy savings at 19% of the total, which is generally in line with its share of the baseline forecast energy consumption. Heavy use of energy for lighting coupled with the availability of numerous lighting efficiency-related measures account for this sector's substantial share of savings potential. The irrigation sector contributes substantially less, both in terms of overall savings potential and in terms of its share of baseline forecast load.

**Figure 22. Energy Efficiency Savings Potential by Sector (2040)**




| | Forecast % | Savings % |
|---|---|---|
| Irrigation | 6.6% | 3.1% |
| Commercial | 17.0% | 19.0% |
| Residential | 27.9% | 34.6% |
| Industrial | 48.6% | 43.3% |

The portfolio of energy efficiency measures can achieve a cumulative demand savings of 23 MW by 2040 (Table 13.) under the Achievable-Moderate scenario. The industrial sector accounts for the largest share of demand savings, followed by the residential sector.

**Table 13. Portfolio Cumulative Demand Savings Potential by Sector by Year (MW)**

| MILESTONE YEAR | INDUSTRIAL | RESIDENTIAL | COMMERCIAL | IRRIGATION | **TOTAL** |
|---|---|---|---|---|---|
| 2021 (first year) | 1.8 | 2.1 | 1.1 | 0.12 | **5.3** |
| 2025 | 3.7 | 3.5 | 2.3 | 0.37 | **9.9** |
| 2030 | 6.7 | 5.8 | 3.7 | 1.1 | **17.2** |
| 2040 | 10.3 | 6.2 | 4.5 | 2.1 | **23.1** |

Table 14 presents cumulative and average annual cost, savings and TRC metrics associated with the Achievable-Moderate scenario. As shown, in the first year Tri-State can achieve 38,083 MWh of energy savings at a cost of approximately $7 million, or $183/MWh. As programs expand and become more established annual costs and savings increase substantially to reach a cumulative program expenditure of nearly $500 million by 2040 and savings of approximately 2,290,400 MWh. The 20-year average annual program costs are approximately $24.3 million and savings are 114,520 MWh.

**Table 14. Portfolio Cost Metrics by Time Horizon (Achievable-Moderate Scenario)**

| MILESTONE YEAR | TRC RATIO | PROGRAM COSTS ($) | SUM OF FIRST-YEAR MEASURE SAVINGS (MWH) | ACQUISTION COST ($/MWH) | LEVELIZED COST ($/MWH) |
|---|---|---|---|---|---|
| 2021 | 2.08 | $6,957,787 | 38,083 | $182.70 | $15.25 |
| 2025 | 1.91 | $54,155,251 | 279,461 | $193.78 | $17.41 |
| 2030 | 1.72 | $164,148,094 | 797,374 | $205.86 | $20.18 |
| 2040 | 1.64 | $486,794,842 | 2,290,399 | $212.54 | $21.55 |
| 20-year avg. | 1.64 | $24,339,742 | 114,520 | $212.54 | $21.55 |

# 5. RESIDENTIAL ENERGY EFFICIENCY POTENTIAL

## 5.1. Overview

The residential sector accounts for just under one-third of the total baseline forecast energy load, and 35% of energy savings potential. Cumulative savings potential for this sector is approximately 5,880 GWh through 2040 (Achievable-Moderate scenario) with lighting efficiency improvements making up over half the total energy savings potential. Central heating improvements comprise almost one-sixth of the residential sector savings potential.

Notable assumptions for the residential sector analysis include: 1) the speed with which lighting market transformation will occur, and 2) the timing of the roll-out and accrual of demand impacts associated with Home Energy Reports (HERs). With regard to lighting, research indicates that LED lamps will become standard technology within 10 years despite delays in implementing lighting efficiency standards under the Energy Independence and Security Act (EISA) of 2007. Lighting measures commonly account for the largest share of savings for residential energy efficiency programs. However, since residential lighting market transformation is well underway, savings from lighting measures are limited for the second half of the evaluation period.

For the home energy reports measure (HER) the analysis assumes a seven-year implementation delay in order to capture demand benefits associated with this measure. This is because Tri-State is not capacity

constrained during this period and avoided cost of capacity benefits do not apply. The addition of demand benefits along with energy savings benefits allows the HERs measure to achieve cost effectiveness for various measure permutations in varying regions.

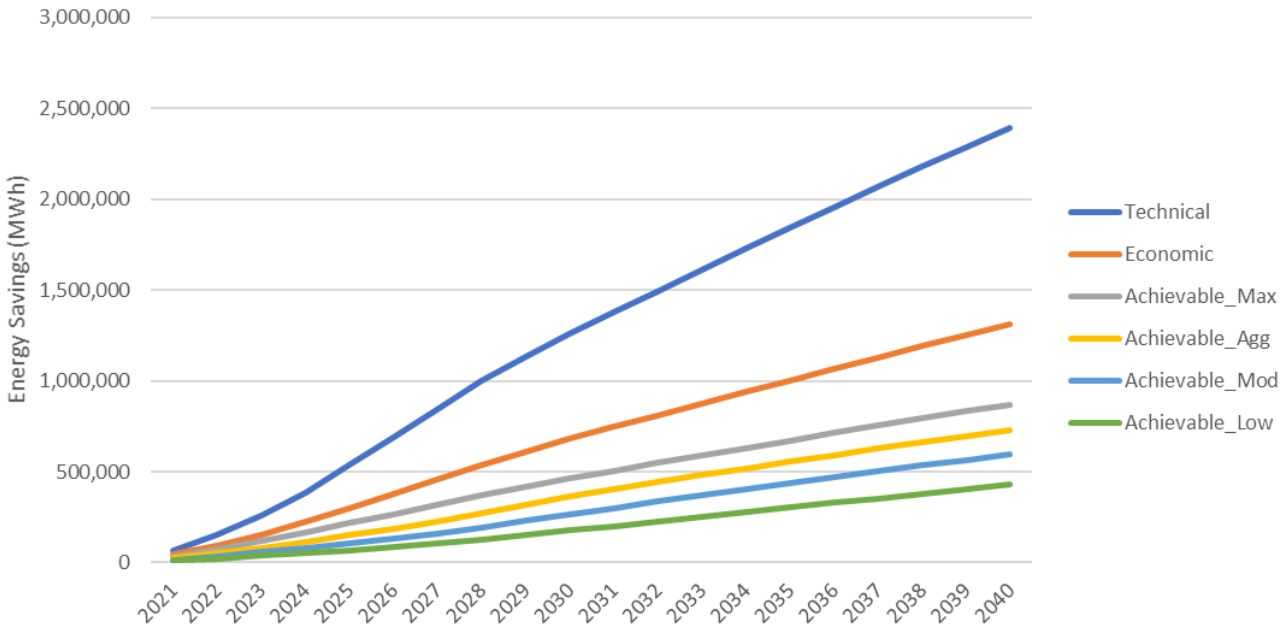
## 5.2. Detailed Results

Table 15 presents cumulative savings potential for the residential sector by scenario at various milestones in the analysis period and Figure 23 shows the growth in cumulative savings potential through 2040. The Achievable-Moderate scenario estimates 14,649 MWh of savings potential in 2021 rising to 594,298 MWh of cumulative savings potential through 2040. Pursuing an aggressive incentive approach (Achievable-Aggressive scenario) could increase cumulative savings potential by approximately 22%. The maximum achievable scenario estimates savings potential approximately 46% higher than the aggressive scenario, equating to cumulative savings of approximately 870,669 MWh through 2040.

**Table 15. Cumulative Residential Savings Potential by Scenario by Time Horizon (MWh)**

| MILESTONE YEAR | TECHNICAL | ECONOMIC | ACHIEVABLE MAX | ACHIEVABLE AGG | ACHIEVABLE MOD | ACHIEVABLE LOW |
|---|---|---|---|---|---|---|
| 2021 (first year) | 63,817 | 42,581 | 34,166 | 22,384 | 14,649 | 9,539 |
| 2025 | 532,961 | 299,459 | 214,988 | 149,245 | 104,278 | 68,016 |
| 2030 | 1,257,012 | 679,699 | 461,040 | 361,598 | 263,762 | 175,118 |
| 2040 | 2,395,940 | 1,313,384 | 870,669 | 726,771 | 594,298 | 427,615 |

**Figure 23. Residential Energy Efficiency Savings Potential by Scenario by Year**



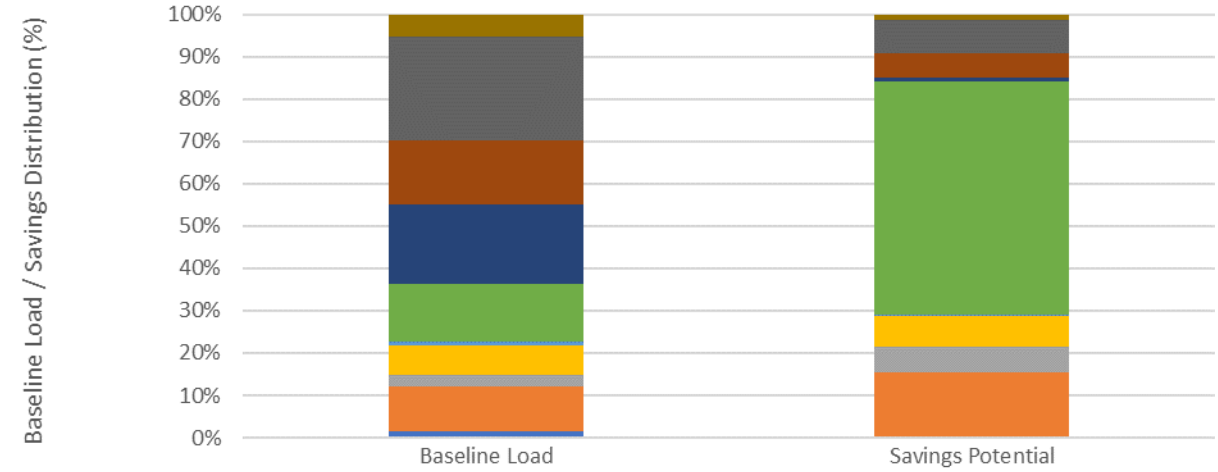
The cumulative residential savings potential under the Achievable-Moderate scenario equates to 9.1% of the residential baseline load forecast for 2040 (see Table 16.). The maximum achievable savings would equate to 16.2% of the forecast energy load for this sector.

**Table 16. Residential Savings Potential as % of Baseline Forecast by Scenario by Year**

| MILESTONE YEAR | TECHNICAL | ECONOMIC | ACHIEVABLE MAX | ACHIEVABLE AGG | ACHIEVABLE MOD | ACHIEVABLE LOW |
|---|---|---|---|---|---|---|
| 2021 (first year) | 1.10% | 0.75% | 0.57% | 0.45% | 0.32% | 0.24% |
| 2025 | 12.48% | 8.63% | 4.36% | 3.36% | 2.25% | 1.54% |
| 2030 | 38.13% | 26.76% | 10.02% | 8.03% | 5.53% | 3.74% |
| 2040 | 76.33% | 53.93% | 16.19% | 13.21% | 9.14% | 6.54% |

As shown in Figure 24, lighting accounts for the greatest share of energy savings potential at 55% of the total followed by central heating at approximately 15% of total savings. Plug loads, central air, HVAC auxiliary, and refrigerator/freezer end-uses combined comprise over a quarter of savings potential.

**Figure 24. Residential Baseline Energy Load and Cumulative Energy Efficiency Savings Potential by End-Use (2040)**




| | Baseline Load | Savings Potential |
|---|---|---|
| Electric Water Heater | 5.4% | 1.3% |
| Plug Loads | 24.5% | 7.8% |
| Refirgerator/Freezer | 14.9% | 5.7% |
| Appliances | 18.9% | 1.1% |
| Lighting | 13.6% | 55.1% |
| Zonal Air | 1.0% | 0.2% |
| Central Air | 6.8% | 7.2% |
| HVAC Aux | 2.9% | 6.1% |
| Central Heating | 10.4% | 15.4% |
| Heat Pump | 1.7% | 0.1% |

Table 17 presents cumulative residential demand savings by end-use by milestone year. High efficiency lighting is by far the greatest contributor to demand savings from residential energy efficiency measures producing 2,722 kW of cumulative demand savings through 2040. Additional measures with relatively large volumes of demand savings include plug loads and central air.

**Table 17. Residential Cumulative Demand Savings Potential by End-Use by Year (MW)**

| YEAR | HEAT PUMP | CENTRAL HEATING | HVAC AUX | CENTRAL AIR | ZONAL AIR | LIGHTING | APPLIANCES | REFRIG-ERATOR / FREEZER | PLUG LOADS | ELECTRIC WH | TOTAL |
|---|---|---|---|---|---|---|---|---|---|---|---|
| 2021 | 0.0002 | 0.0053 | 0.0122 | 0.0951 | 0.0 | 1.8303 | 0.0080 | 0.0605 | 0.1238 | 0.0100 | **2.1454** |
| 2025 | 0.0008 | 0.0203 | 0.0538 | 0.3813 | 0.0 | 2.4448 | 0.0296 | 0.1921 | 0.3284 | 0.0408 | **3.4921** |
| 2030 | 0.0031 | 0.0505 | 0.1460 | 1.5397 | 0.0806 | 2.9055 | 0.0990 | 0.3152 | 0.5296 | 0.1378 | **5.8072** |

| | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|
| 2040 | 0.0037 | 0.0440 | 0.2012 | 1.7245 | 0.0829 | 2.7220 | 0.1116 | 0.3383 | 0.7502 | 0.1771 | **6.1554** |

Table 18. presents cumulative program cost metrics by milestone year. As shown, first-year program costs are approximately $3.0 million, rising to a 20-year average annual cost of approximately $8.9 millon. Acquisition costs rise from $206/MWh in 2021 to $251/MWh in 2040. A change in lighting market measures available during the analysis period drives this increase in acquisition costs, as LEDs become the market baseline within ten years. The decline in highly cost-effective lighting measures also has a downward effect on the TRC ratio, as it decreases from 2.15 in 2021 to 1.36 in 2040.

**Table 18. Cumulative Residential Cost Metrics by Time Horizon**

| MILESTONE YEAR | TRC RATIO | PROGRAM COSTS ($) | SUM 1st-YEAR MEASURE SAVINGS (MWH) | ACQUISTION COST ($/MWH) | LEVELIZED COST ($/MWH) |
|---|---|---|---|---|---|
| 2021 | 2.15 | $ 3,013,704 | 14,649 | $ 205.72 | $ 14.90 |
| 2025 | 1.84 | $ 23,693,929 | 104,884 | $ 225.91 | $ 18.61 |
| 2030 | 1.50 | $ 68,913,983 | 280,300 | $ 245.86 | $ 23.95 |
| 2040 | 1.36 | $ 177,217,648 | 705,466 | $ 251.21 | $ 26.52 |
| 20-year avg. | 1.36 | $ 8,860,882 | 35,273 | $ 251.21 | $ 26.52 |

# 6. COMMERCIAL ENERGY EFFICIENCY POTENTIAL

## 6.1. Overview

The commercial sector accounts for 17% of the total baseline forecast energy load, and 19% of cumulative energy savings potential in 2040. Cumulative savings potential for this sector is approximately 326 GWh through 2040 (Achievable-Moderate scenario) with lighting measures making up 74% of the total energy savings potential. Other end-uses comprising a notable share of savings potential include refrigeration, motors and plug load at 7.5%, 5% and 4% of savings respectively. The retail segment holds the largest opportunity for savings at roughly 27% of the cumulative savings potential in 2040.

## 6.2. Detailed Results

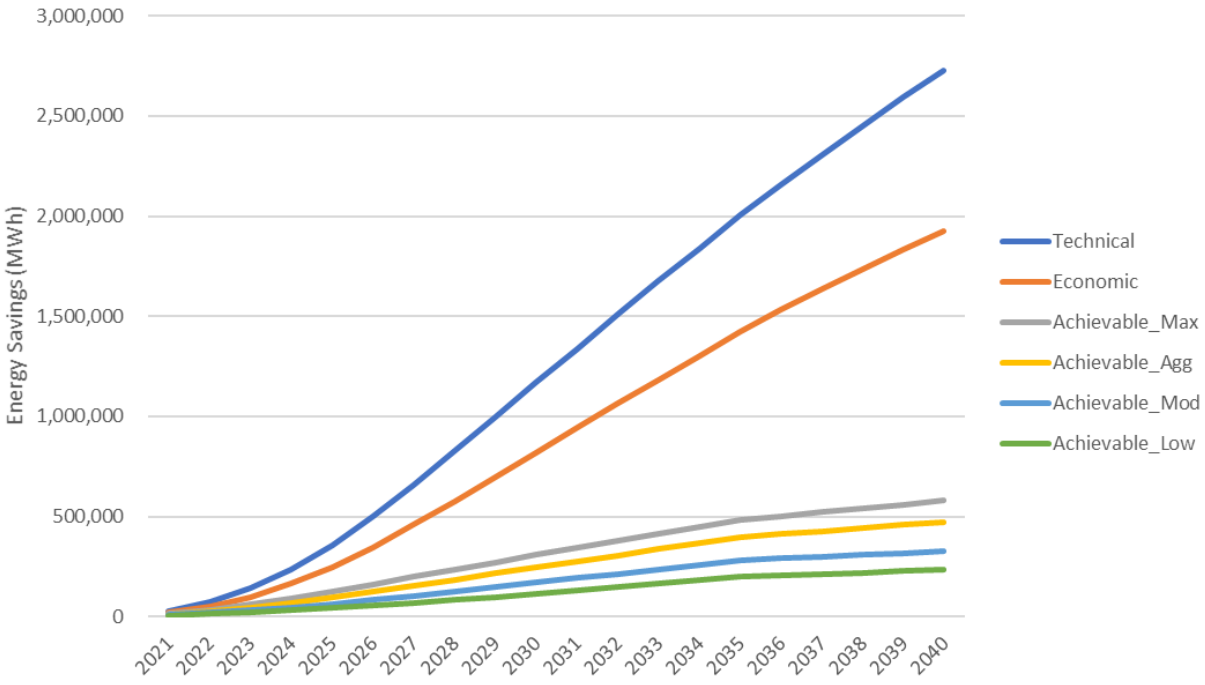
Table 19. presents cumulative savings potential for the commercial sector by scenario at various milestones in the analysis period and Figure 25 shows the growth in cumulative savings potential through 2040. The Achievable-Moderate scenario estimates 8.6 GWh of savings potential in 2021 rising to approximately 326 GWh of cumulative savings potential through 2040. Pursuing an aggressive program-delivery approach (Achievable-Aggressive scenario) could increase cumulative savings potential

by approximately 45% to 472 GWh. A less aggressive program delivery approach (Achievable-Low scenario) would reduce savings by approximately 30% relative to the Achievable-Moderatemoderate scenario.

**Table 19. Cumulative Commercial Savings Potential by Scenario by Time Horizon (MWh)**

| MILESTONE YEAR | TECHNICAL | ECONOMIC | ACHIEVABLE MAX | ACHIEVABLE AGG | ACHIEVABLE MOD | ACHIEVABLE LOW |
|---|---|---|---|---|---|---|
| 2021 (first year) | 29,723 | 20,331 | 15,375 | 12,230 | 8,626 | 6,372 |
| 2025 | 356,164 | 246,342 | 124,400 | 95,929 | 64,202 | 43,820 |
| 2030 | 1,167,833 | 819,729 | 307,053 | 245,955 | 169,298 | 114,633 |
| 2040 | 2,726,737 | 1,926,747 | 578,473 | 472,062 | 326,383 | 233,706 |

**Figure 25. Commercial Cumulative Energy Efficiency Savings Potential by Sector by Year**




The cumulative commercial savings potential under the Achievable-Moderate scenario equates to a reduction of 0.32% of commercial baseline sales in 2021, a 2.25% reduction by 2025 and a 9.14% reduction by 2040 (see Table 20.). The Mesa Point Energy Team esimates a range in reduction of baseline energy sales for the achievable scenarios from 6.5% (Achievable-Low) to 16.2% (Achievable-Max) by 2040.

**Table 20. Commercial Cumulative Savings Potential as % of Baseline Forecast by Sector by Year**

| MILESTONE YEAR | TECHNICAL | ECONOMIC | ACHIEVABLE MAX | ACHIEVABLE AGG | ACHIEVABLE MOD | ACHIEVABLE LOW |
|---|---|---|---|---|---|---|
| 2021 (first year) | 1.10% | 0.75% | 0.57% | 0.45% | 0.32% | 0.24% |
| 2025 | 12.48% | 8.63% | 4.36% | 3.36% | 2.25% | 1.54% |
| 2030 | 38.13% | 26.76% | 10.02% | 8.03% | 5.53% | 3.74% |
| 2040 | 76.33% | 53.93% | 16.19% | 13.21% | 9.14% | 6.54% |

As shown in Figure 26 lighting makes up a large majority of the commercial sector's energy savings potential at 74%, a significant increase in its baseline load share. Refrigeration, motors and plug loads comprise most of the remaining savings potential for this sector at 7.5%, 5.5% and 4% respectively.

**Figure 26. Commercial Baseline Energy Load and Cumulative Energy Efficiency Savings Potential Distribution by End-Use (2040)**

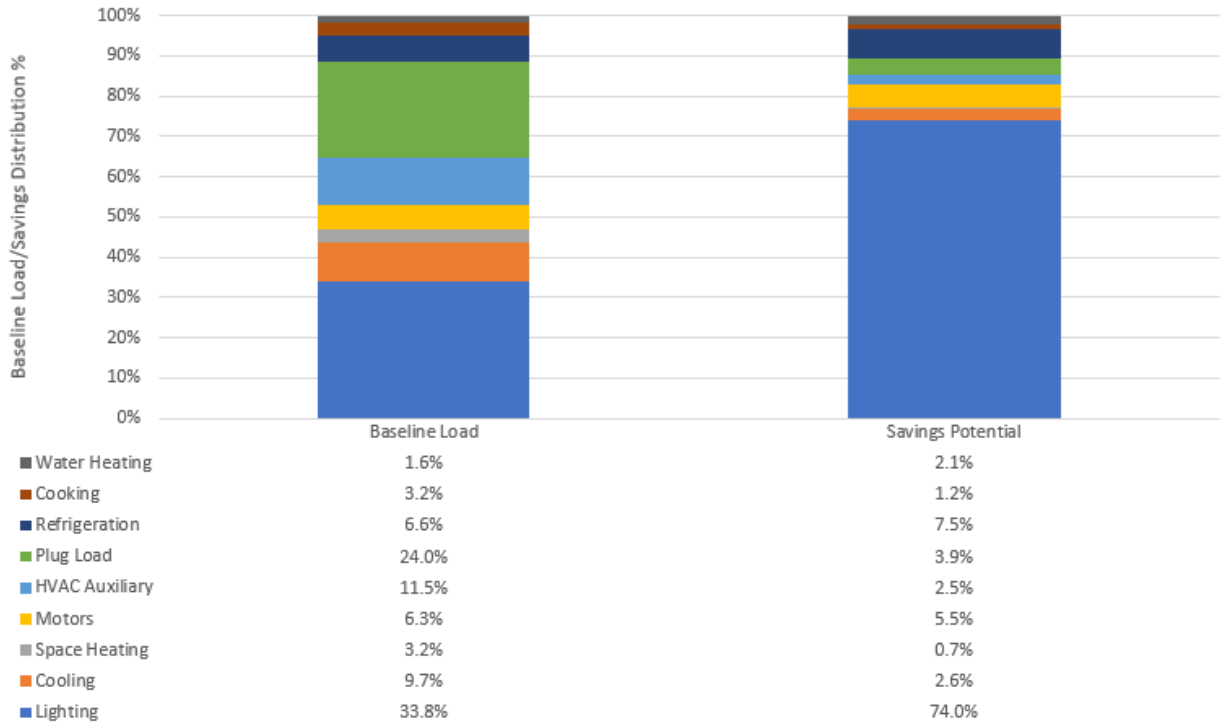



Table 21 presents cumulative commercial demand reductions by end-use by milestone year. Lighting accounts for nearly 55% of demand savings from commercial energy efficiency measures, producing almost 2,500 kW of demand reductions by 2040. Relative to their energy savings, the Cooling and HVAC Auxillary end-uses provide a large demand reduction opportunity at 430 kW and 424 kW respectively.

**Table 21. Commercial Cumulative Demand Savings Potential by End-Use by Year (MW)**

| YEAR | LIGHTING | COOLING | HEATING | MOTORS | HVAC AUX | PLUG LOAD | REFRIGER-ATION | COOKING | DHW | TOTAL |
|---|---|---|---|---|---|---|---|---|---|---|
| 2021 (first year) | 0.763 | O.054 | 0.001 | 0.0251 | 0.054 | 0.102 | 0.108 | 0.011 | 0.014 | **1.133** |
| 2025 | 1.526 | 0.147 | 0.002 | 0.0693 | 0.145 | 0.161 | 0.230 | 0.025 | 0.039 | **2.344** |
| 2030 | 2.171 | 0.310 | 0.004 | O.1529 | 0.305 | 0.233 | 0.353 | 0.041 | 0.082 | **3.653** |
| 2040 | 2.476 | 0.430 | 0.006 | 0.2206 | 0.424 | 0.357 | 0.434 | 0.053 | 0.116 | **4.517** |

Figure 27 presents baseline energy load and cumulative savings by commercial market segment through 2040. The savings potential for each segment is generally similar to its share of total baseline energy load. The retail segment has the largest share of 2040 cumulative savings potential (27.4%), an increase of just over 7% of its baseline energy load share. This is a result of the large lighting load share in retail buildings. The Miscellaneous and Office segments comprise the next largest opportunities at 17.7% and 10.4% of cumulative savings potential respectively.

**Figure 27. Commercial Baseline Load and Cumulative Energy Efficiency Savings Potential Distribution by Segment (2040)**

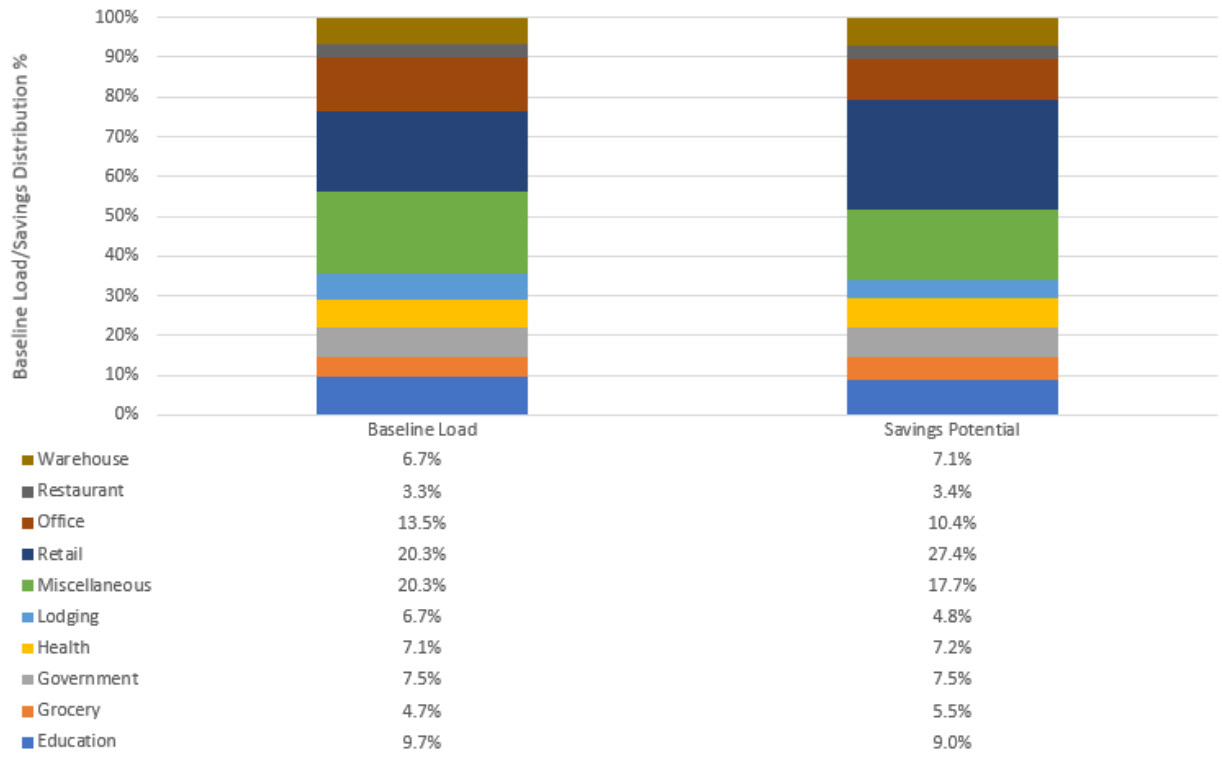


Table 22. summarizes cumulative commercial program cost metrics by milestone year. As shown, first-year program costs are approximately $1.4 million, rising to a 20-year average annual cost of roughly $4.1 millon. Acquisition costs start at $159/MWh during the first year of analysis and see a gradual increase through 2040. The TRC ratio remains solid for the commercial sector starting at 2.11 in 2021 and decreasing modestly to 1.93 in 2040.

**Table 22. Commercial Cost Metrics by Time Horizon**

| MILESTONE YEAR | TRC RATIO | PROGRAM COSTS ($) | SUM 1st-YEAR MEASURE SAVINGS (MWH) | ACQUISTION COST ($/MWH) | LEVELIZED COST ($/MWH) |
|---|---|---|---|---|---|
| 2021 | 2.11 | $ 1,367,761 | 8,626 | $ 158.57 | $ 18.87 |
| 2025 | 2.07 | $ 10,437,397 | 64,743 | $ 161.21 | $19.27 |
| 2030 | 2.01 | $ 30,065,223 | 181,191 | $ 165.93 | $ 20.13 |
| 2040 | 1.93 | $ 82,522,317 | 481,235 | $ 171.48 | $ 21.24 |
| 20-year avg. | 1.93 | $ 4,126,116 | 24,062 | $ 171.48 | $ 21.24 |

# 7. INDUSTRIAL ENERGY EFFICIENCY POTENTIAL

## 7.1. Overview

The industrial sector makes up roughly one-half of Tri-State's total baseline forecast energy load, and 43% of potential energy savings. Cumulative savings potential for this sector is approximately 745 GWh through 2040 (Achievable-Moderate scenario) with pump-related savings accounting for a majority of potential savings at 58%. Efficiency measures for the oil and gas segment of the market comprise nearly 55% of potential savings for this sector. Manufacturing-related efficiency opportunities account for most of the remaining energy savings potential.

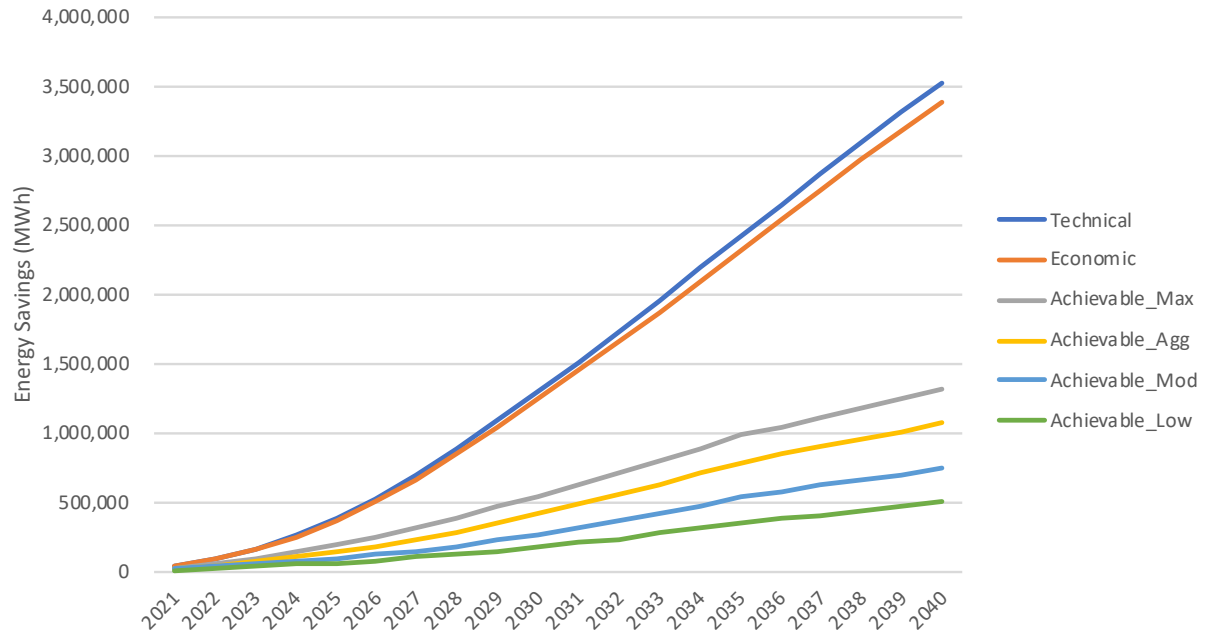
## 7.2. Detailed Results

Table 23 presents cumulative savings potential for the industrial sector by scenario at various milestones in the analysis period and Figure 28 shows the growth in cumulative savings potential through 2040. The Achievable-Moderate scenario estimates 14 GWh of savings potential in 2021 rising to approximately 745 GWh of cumulative savings potential through 2040. Pursuing an aggressive incentive approach (Achievable-Aggressive scenario) could increase cumulative savings potential by approximately 43%. Savings potential increases by an additional 22% under the maximum achievable scenario, equating to a a cumulative maximum achievable savings of approximately 1,308 GWh through 2040.

**Table 23. Cumulative Industrial Savings Potential by Scenario by Time Horizon (MWh)**

| MILESTONE YEAR | TECHNICAL | ECONOMIC | ACHIEVABLE MAX | ACHIEVABLE AGG | ACHIEVABLE MOD | ACHIEVABLE LOW |
|---|---|---|---|---|---|---|
| 2021 (first year) | 35,303 | 34,181 | 24,956 | 19,902 | 14,224 | 10,678 |
| 2025 | 378,791 | 363,954 | 186,953 | 139,453 | 92,325 | 63,777 |
| 2030 | 1,294,201 | 1,240,358 | 544,166 | 414,383 | 268,351 | 173,960 |
| 2040 | 3,523,534 | 3,381,672 | 1,307,552 | 1,066,805 | 744,543 | 502,719 |

**Figure 28. Industrial Energy Efficiency Savings Potential by Scenario by Year**



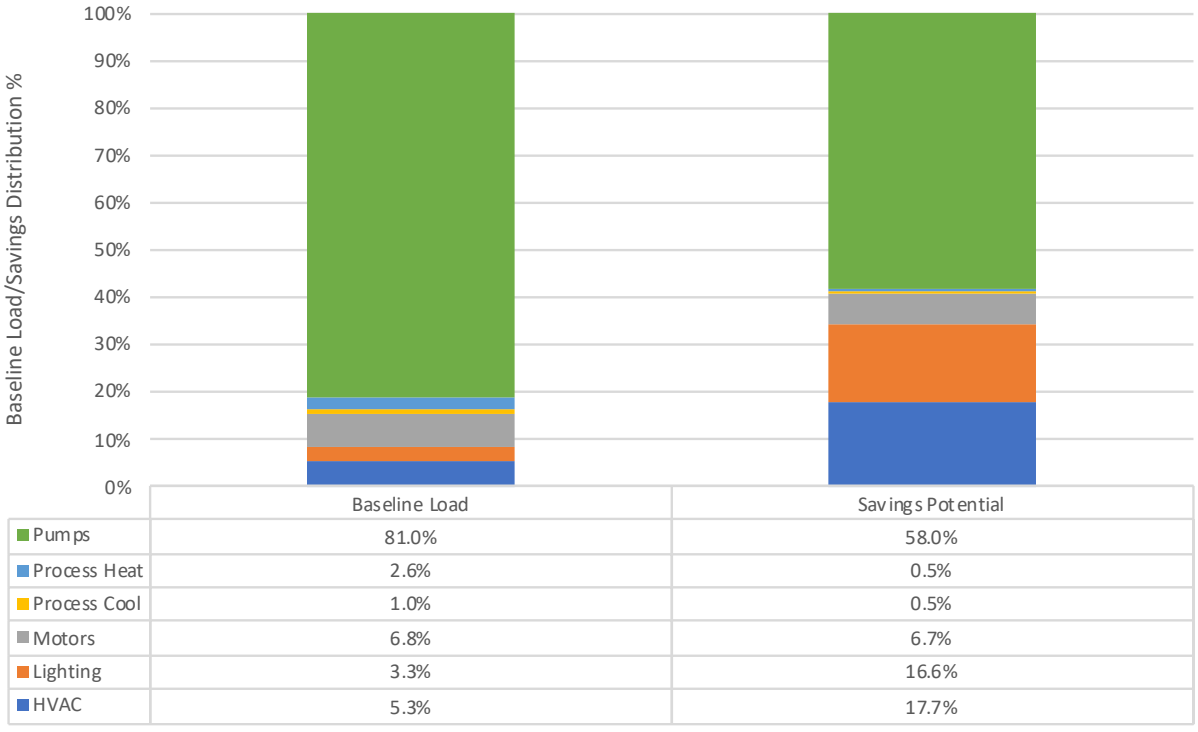

The cumulative industrial savings potential under the Achievable-Moderate scenario equates to a reduction of 0.21% of industrial baseline sales in 2021, a 1.24% reduction by 2025 and a 7.28% reduction by 2040 (see Table 24.). The analysis estimates a range in reduction of baseline energy sales for the achievable scenarios from 4.9% (Achievable-Low) to 12.8% (Achievable-Max) by 2040.

**Table 24. Industrial Cumulative Savings Potential as % of Baseline Forecast by Sector by Year**

| MILESTONE YEAR | TECHNICAL | ECONOMIC | ACHIEVABLE MAX | ACHIEVABLE AGG | ACHIEVABLE MOD | ACHIEVABLE LOW |
|---|---|---|---|---|---|---|
| 2021 (first year) | 0.52% | 0.50% | 0.36% | 0.29% | 0.21% | 0.16% |
| 2025 | 5.09% | 4.89% | 2.51% | 1.87% | 1.24% | 0.86% |
| 2030 | 15.66% | 15.01% | 6.58% | 5.01% | 3.25% | 2.10% |
| 2040 | 34.44% | 33.05% | 12.78% | 10.43% | 7.28% | 4.91% |

As shown in Figure 29 efficient pumps and related measures hold by far the greatest energy savings potential for the industrial sector, accounting for nearly 60% of the total. This is in part due to the fact that pumps account for such a large portion of the industrial sector's forecast baseline energy load (81%). Lighting and HVAC also hold substantial energy savings potential for this sector at 17% and 18% of the total, respectively.

**Figure 29. Industrial Baseline Energy Load and Cumulative Energy Efficiency Savings Potential Distribution by End-Use (2040)**




| | Baseline Load | Savings Potential |
|---|---|---|
| Pumps | 81.0% | 58.0% |
| Process Heat | 2.6% | 0.5% |
| Process Cool | 1.0% | 0.5% |
| Motors | 6.8% | 6.7% |
| Lighting | 3.3% | 16.6% |
| HVAC | 5.3% | 17.7% |

Table 25. presents cumulative industrial demand savings by end-use by milestone year. As with energy savings potential, pumps are also the leader in terms of demand savings potential. Pump-related

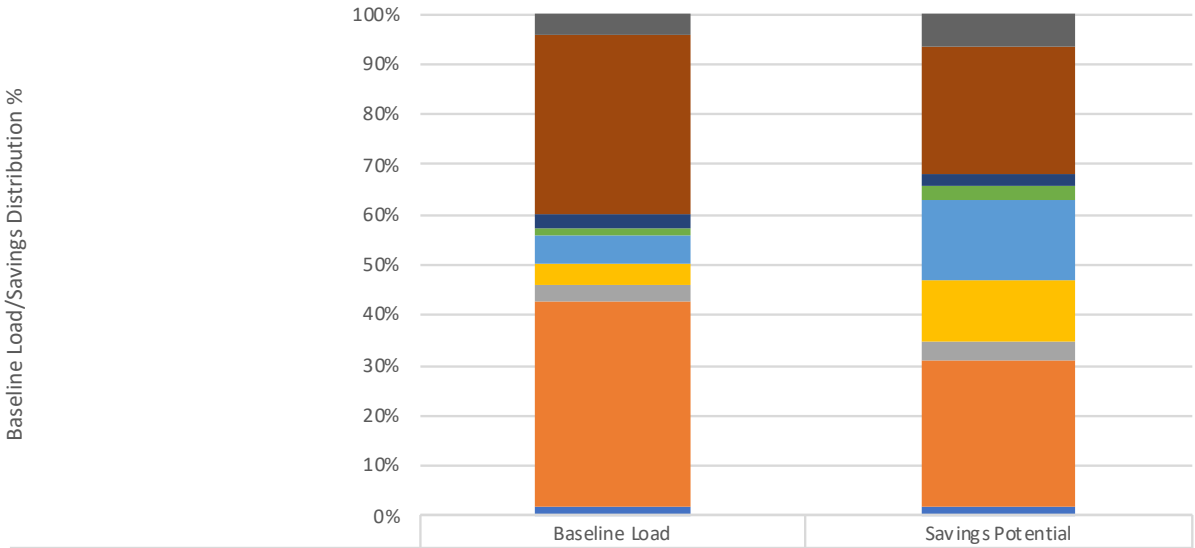
measures contribute nearly 6.6 MW of cumulative demand savings potential. Lighting efficiency measures have the potential to decrease demand by almost 1.3 MW and HVAC by nearly 1.7 MW.

**Table 25. Industrial Cumulative Demand Savings Potential by End-Use by Year (MW)**

| YEAR | HVAC | LIGHTING | MOTORS | PROCESS COOL | PROCESS HEAT | PUMPS | TOTAL |
|---|---|---|---|---|---|---|---|
| 2021 (first year) | 0.165 | 0.201 | 0.132 | 0.008 | 0.008 | 1.364 | **1.878** |
| 2025 | 0.469 | 0.496 | 0.242 | 0.022 | 0.020 | 2.456 | **3.705** |
| 2030 | 1.076 | 0.898 | 0.424 | 0.047 | 0.037 | 4.187 | **6.669** |
| 2040 | 1.686 | 1.258 | 0.672 | 0.070 | 0.052 | 6.597 | **10.335** |

Figure 30 shows that liquid mining and pipeline transportation are the two segments of the industrial sector that account for the most energy savings potential, at more than one-quarter of the total for each segement. Together, these two segments account for approximately 55% of the savings potential. Manufacturing-related segments (i.e., non-metallic mineral products, chemical, paper and other manufacturing segments) together make up over one-third of the total energy savings potential.

**Figure 30. Industrial Baseline Load and Cumulative Energy Efficiency Savings Potential Distribution by Segment (2040)**




| | Baseline Load | Savings Potential |
|---|---|---|
| TCU | 4.2% | 6.6% |
| Pipeline Transportation (Oil, Gas, and CO2) | 35.6% | 25.5% |
| Mining | 3.0% | 2.0% |
| Mfg - Paper | 1.6% | 3.2% |
| Mfg - Nonmetallic Mineral Product | 5.3% | 15.9% |
| Mfg - Misc. | 4.6% | 12.1% |
| Mfg - Chemical | 3.2% | 3.9% |
| Liquid Mining (Oil, Gas, and Carbon Dioxide) | 40.8% | 29.2% |
| Agriculture | 1.8% | 1.7% |

Table 26. summarizes cumulative industrial program cost metrics by milestone year. As shown, first-year program costs are approximately $2.4 million, rising to a 20-year average annual cost of roughly $9.6 millon. Acquisition costs start at $168/MWh during the first year of analysis and see only a slight increase through 2040. The TRC ratio remains solid for the industrial sector starting at 2.08 in 2021 and decreasing modestly to 1.92 in 2040.

**Table 26. Industrial Cost Metrics by Time Horizon**

| MILESTONE YEAR | TRC RATIO | PROGRAM COSTS ($) | SUM 1st-YEAR MEASURE SAVINGS (MWH) | ACQUISTION COST ($/MWH) | LEVELIZED COST ($/MWH) |
|---|---|---|---|---|---|
| 2021 | 2.08 | $2,391,009 | 14,224 | $168.09 | $11.67 |
| 2025 | 2.02 | $18,273,240 | 104,319 | $175.17 | $12.80 |
| 2030 | 1.96 | $57,536,744 | 311,837 | $184.51 | $14.14 |

| | | | | | |
|---|---|---|---|---|---|
| 2040 | 1.92 | $192,026,153 | 993,332 | $193.32 | $15.25 |
| 20-year avg. | 1.92 | $9,601,308 | **49,667** | **$193.32** | **$15.25** |

# 8. IRRIGATION EFFICIENCY POTENTIAL

## 8.1. Overview

Irrigation accounts for a small fraction of energy consumption and savings potential; it represents approximately 8% of Tri-State's total baseline energy load, and 3% of potential energy savings. Cumulative savings potential for this sector is approximately 53,134 MWh through 2040 (Achievable-Moderate scenario). Measures with notable savings potential include high efficiency motors, motor VFDs and base boot gasket improvements, making up approximately 63%, 18% and 17% of total savings potential respectively.

## 8.2. Detailed Results

Table 27 presents cumulative savings potential for the irrigation sector by scenario at various milestones in the analysis period and Figure 31 shows the growth in cumulative savings potential through 2040. The Achievable-Moderate scenario estimates 584 MWh of savings potential in 2021 rising to approximately 53,134 MWh of cumulative savings potential through 2040. Pursuing an aggressive incentive approach (Achievable-Aggressive scenario) could increase cumulative savings potential by approximately 70%. Savings potential increases by an additionad 39% under the maximum achievable scenario, equating to a a cumulative maximum achievable savings of approximately 119,793 MWh through 2040.

**Table 27. Cumulative Irrigation Savings Potential by Scenario by Time Horizon (MWh)**

| MILESTONE YEAR | TECHNICAL | ECONOMIC | ACHIEVABLE MAX | ACHIEVABLE AGG | ACHIEVABLE MOD | ACHIEVABLE LOW |
|---|---|---|---|---|---|---|
| 2021 (first year) | 1,541 | 1,128 | 1,026 | 814 | 584 | 454 |
| 2025 | 25,117 | 18,368 | 13,409 | 9,028 | 5,504 | 3,609 |
| 2030 | 149,894 | 111,385 | 60,712 | 40,289 | 22,193 | 12,282 |
| 2040 | 435,221 | 334,704 | 119,793 | 88,727 | 53,134 | 29,070 |

**Figure 31. Irrigation Energy Efficiency Savings Potential by Scenario by Year**

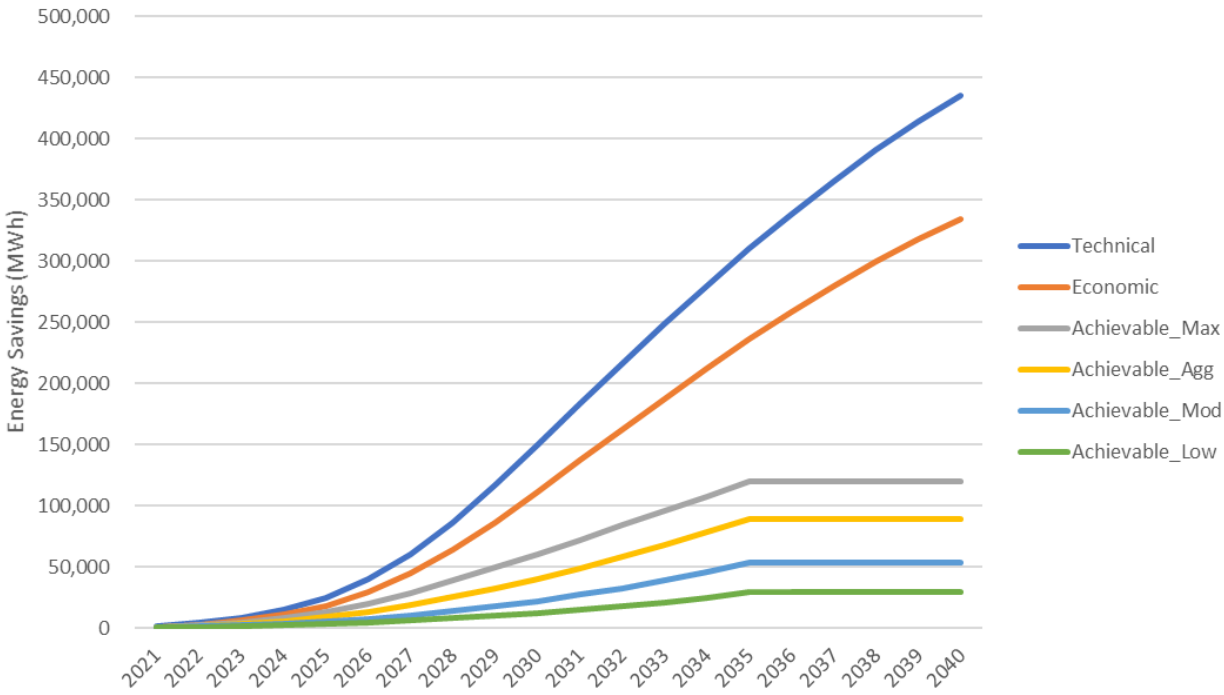



Table 28. shows the percentage impact of cumulative irrigation savings on the baseline forecast by scenario for each milestone year. Under the Achievable-Moderate scenario irrigation measures have the potential to reduce baseline load by nearly 4%. The maximum achievable scenario would more than double those savings to reduce baseline load by approximately 9%.

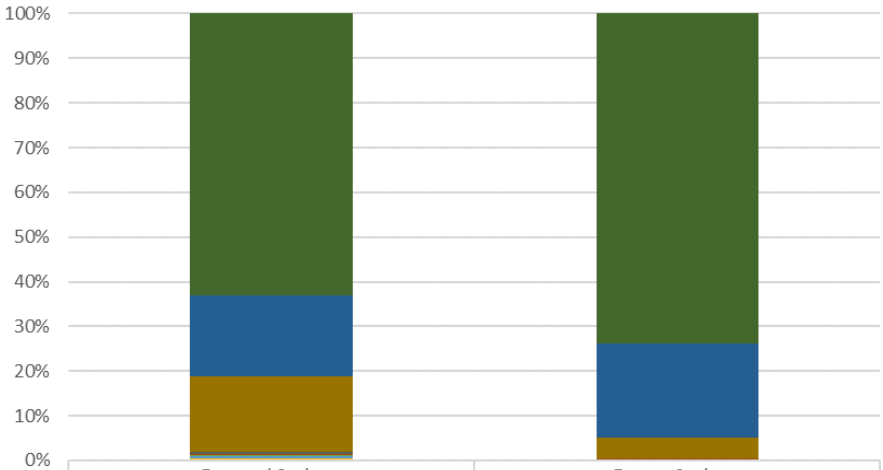
Eastern Colorado accounts for approximately half the irrigation savings potential, followed by Nebraska at approximately 30% of the total. Northern and Southern New Mexico together account for approximately 12% of total irrigation savings potential with the remaining regions making up a nominal share of total irrigation savings potential.

**Table 28. Irrigation Cumulative Savings Potential as % of Baseline Forecast by Sector by Year**

| MILESTONE YEAR | TECHNICAL | ECONOMIC | ACHIEVABLE MAX | ACHIEVABLE AGG | ACHIEVABLE MOD | ACHIEVABLE LOW |
|---|---|---|---|---|---|---|
| 2021 (first year) | 0.12% | 0.09% | 0.08% | 0.06% | 0.04% | 0.03% |
| 2025 | 1.90% | 1.39% | 1.01% | 0.68% | 0.42% | 0.27% |
| 2030 | 11.17% | 8.30% | 4.52% | 3.00% | 1.65% | 0.91% |
| 2040 | 31.51% | 24.23% | 8.67% | 6.42% | 3.85% | 2.10% |

Figure 32 shows the range of measures examined as part of the analysis, as well as the share of total demand and energy savings each measure represents. High efficiency motors comprise by far the largest share of savings at 63% of demand and approximately 74% of energy savings. Motor VFDs and base boot gaskets also represent notable savings opportunities. Other measures, like upgrades to Low Elevation Spray Application (LESA) and Low Energy Precision Application (LEPA) and scheduling-related measures may hold potential for improving customer satisfaction, as they can reduce water use and improve crop yields. However, LESA and LEPA are not found to provide substantial energy savings, and the analysis Team did not explore scheduling-related measures as part of this analysis.

**Figure 32. Irrigation Cumulative Demand and Energy Savings by Measure (2040)**




| | Demand Savings | Energy Savings |
|---|---|---|
| HE Motor | 63.07% | 73.81% |
| Motor VFD | 18.02% | 21.18% |
| Base boot gasket | 16.91% | 4.52% |
| Cut and press repair | 0.43% | 0.12% |
| Hub gasket | 0.25% | 0.11% |
| Upgrade from high pressure to LESA/LEPA/MDI | 0.22% | 0.10% |
| Upgrade from high pressure to MESA | 0.20% | 0.09% |
| Sprinkler package replacement, high pressure | 0.41% | 0.03% |
| Nozzle replacement | 0.24% | 0.02% |
| Gaskets | 0.15% | 0.02% |
| Drains | 0.08% | 0.01% |
| Sprinkler package replacement, MESA | 0.02% | 0.00% |

Table 29. presents cumulative and average annual costs, savings and TRC metrics associated with the Achievable-Moderate scenario for irrigation efficiency measures. As shown, in the first year Tri-State can achieve approximately 584 MWh of energy savings at a cost of approximately $185,313, or a levelized cost of $47.49/MWh. As programs expand and become more established annual costs and savings increase substantially. The 20-year average annual program costs are approximately $1.75 million and savings are 5,518 MWh.

**Table 29. Irrigation Cumulative Cost Metrics by Time Horizon**

| MILESTONE YEAR | TRC RATIO | PROGRAM COSTS ($) | SUM OF 1st-YEAR MEASURE SAVINGS (MWH) | ACQUISTION COST ($/MWH) | LEVELIZED COST ($/MWH) |
|---|---|---|---|---|---|
| 2021 | 0.99 | $185,313 | 584 | $317.40 | $47.49 |
| 2025 | 0.99 | $1,750,685 | 5,516 | $317.39 | $47.50 |
| 2030 | 0.99 | $7,632,143 | 24,046 | $317.40 | $47.51 |
| 2040 | 0.99 | $35,028,723 | 110,365 | $317.39 | $47.53 |
| 20-year avg. | **0.99** | $1,751,436 | 5,518 | $317.39 | $47.53 |

# 9. DEMAND RESPONSE POTENTIAL STUDY

## 9.1. Overview

The analysis finds that a Tri-State portfolio of demand response programs could cost effectively contribute 86 MW of demand curtailment during the summer peak window by the end of the 20-year analysis time horizon. This result (the Achievable-Low scenario) assumes conservative realistic participation rates across Tri-State's territory.

Table 30 presents portfolio-level demand response potential by time horizon. As Tri-State does not currently offer demand response programs, each scenario ramps from zero and then plateaus when the program achieves maturity. The Achievable-Low scenario estimates 86 MW of cumulative summer demand response potential in 2040. Achieving more aggressive participation rates through increased marketing and incentive costs could yield an estimated 245 MW of potential (Achievable-High scenario).

**Table 30. Cumulative Demand Response Potential (MW) By Scenario By Time Horizon**

| MILESTONE YEAR | TECHNICAL | ECONOMIC | ACHIEVABLE HIGH | ACHIEVABLE LOW |
|---|---|---|---|---|
| 2021 | 46 | 30 | 12 | 5 |
| 2025 | 297 | 196 | 85 | 30 |
| 2030 | 647 | 500 | 222 | 78 |
| 2040 | 704 | 548 | 245 | 86 |

**Figure 33. Portfolio Demand Response Potential by Scenario by Year**

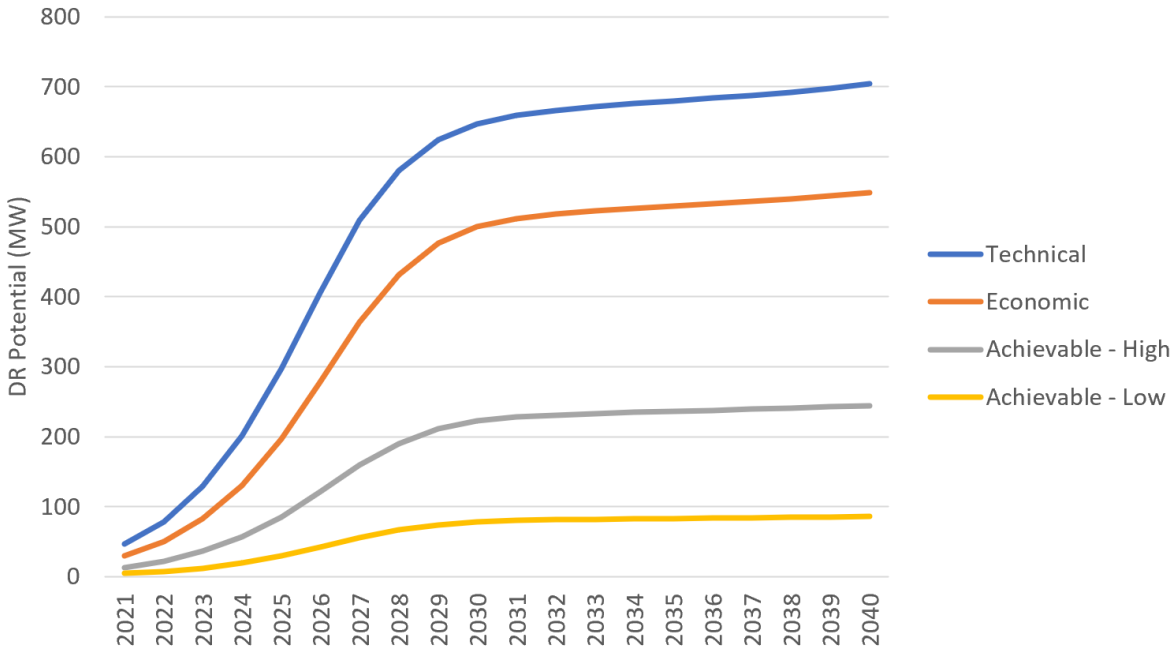



Table 31. shows the impacts of demand response potential relative to Tri-State's baseline demand forecast. The Achievable-High and -Low scenarios represent about 6.90% and 2.43% of forecasted coincident demand in 2040 respectively.

**Table 31. Portfolio Demand Response Potential as % of Baseline Forecast by Year**

| MILESTONE YEAR | TECHNICAL | ECONOMIC | ACHIEVABLE HIGH | ACHIEVABLE LOW |
|---|---|---|---|---|
| 2021 | 1.65% | 1.07% | 0.48% | 0.16% |
| 2025 | 9.99% | 6.61% | 2.87% | 1.00% |
| 2030 | 20.43% | 15.79% | 7.03% | 2.47% |
| 2040 | 19.85% | 15.46% | 6.90% | 2.43% |

Figure 34 and Figure 35 show contributions to the portfolio-level demand response potential by sector and by program type respectively. In each scenario, the largest contributors to the demand response potential are the residential and irrigation sectors. Connected device programs, primarily Smart Thermostat programs, and Direct Load Control (DLC), primarily for irrigation pumping, are the most significant program types.

This analysis considered two different time-varying rates programs – **Critical Peak Pricing without Enabling Technology** (CPP no tech), and **Time Of Use** (TOU) – in each sector. As Tri-State does not control customer rates, implementing this type of demand response program would require a high level of collaboration with electric cooperatives.

**Figure 34. Portfolio Demand Response Potential by Sector (2040)**

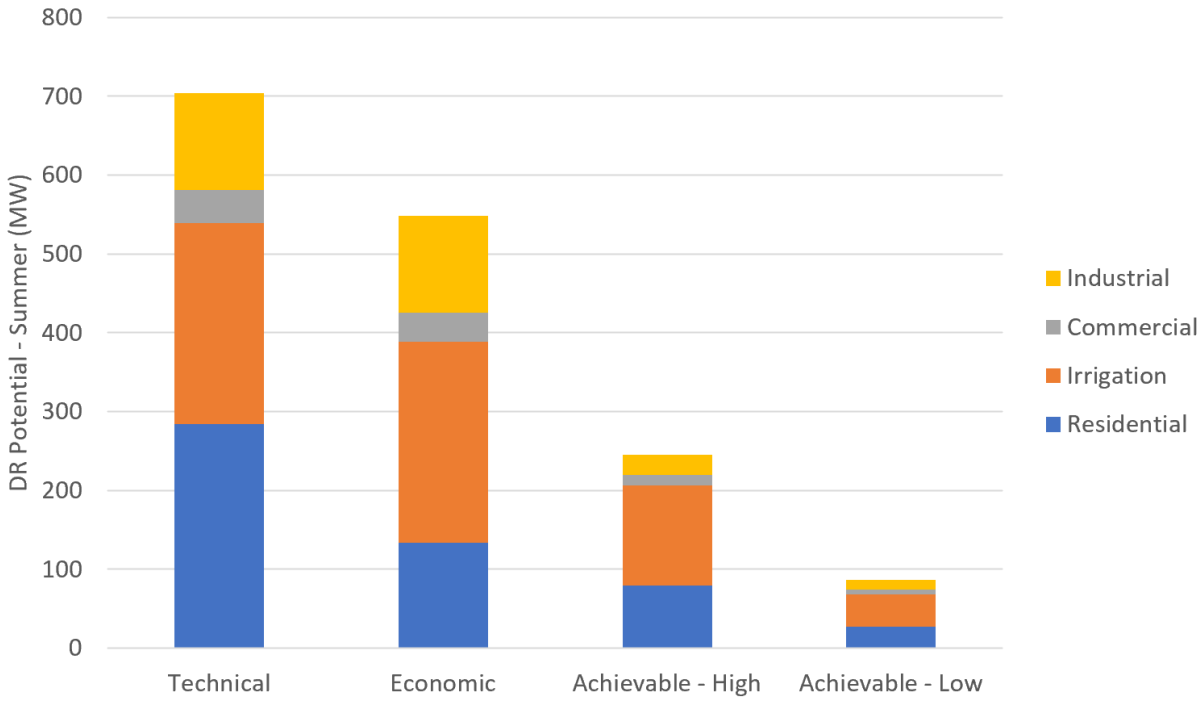
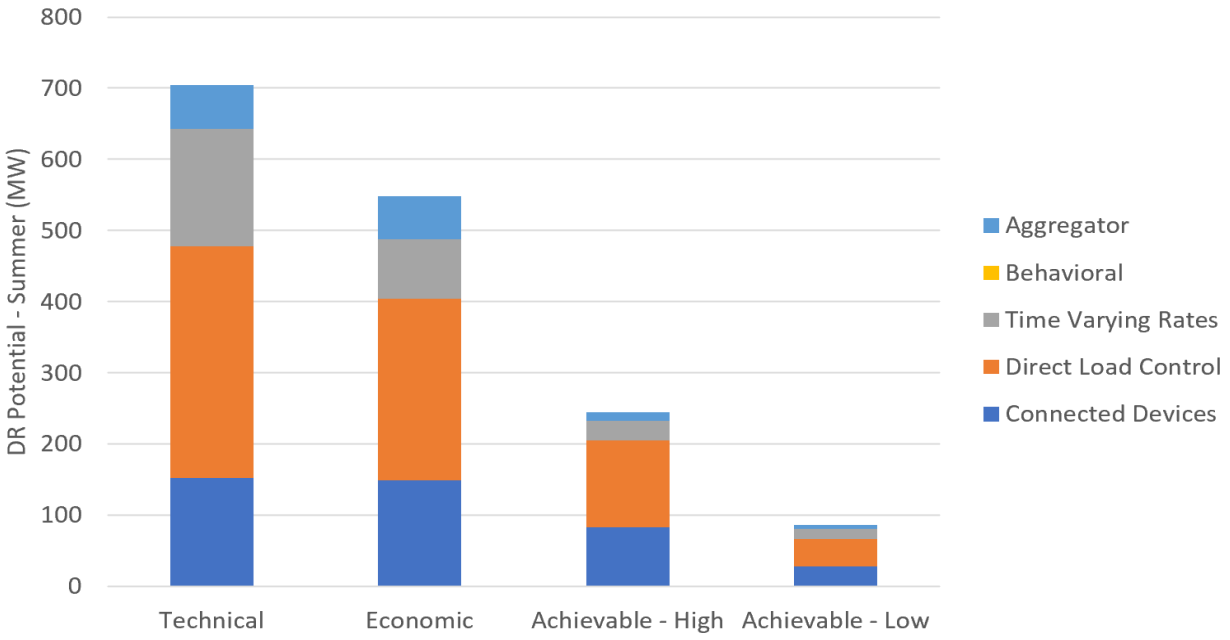



**Figure 35. Portfolio Demand Response Potential by Program Type (2040)[16]**




[16] Behavioral value is too small to observe.

Table 32 summarizes the demand response cost metrics across the portfolio at each time horizon under the Achievable-Low scenario. By the end of the 20-year study horizon, the estimated 86 MW of peak demand savings is achievable at a cost of $39 million. The Net Present Value TRC ratio of the demand response portfolio is cost effective by the end of the horizon (1.16 TRC), but not cost effective in the more immediate time horizons. This characteristic is largely driven by Tri-State's negligible costs of capacity for 2021 through 2026 with an increase in 2027.

**Table 32. Portfolio Demand Response Cost Metrics by Time Horizon (Achievable-Low Scenario)**

| MILESTONE YEAR | TRC RATIO | CUMULATIVE PROGRAM COST ($) | DR POTENTIAL (MW) |
|---|---|---|---|
| 2021 | 0.02 | $5,440,119 | 5 |
| 2025 | 0.09 | $13,818,802 | 30 |
| 2030 | 0.60 | $24,286,062 | 78 |
| 2040 | 1.16 | $39,068,285 | 86 |

## 9.2. Residential Sector Demand Response Potential

Figure 36 shows how demand response potential for residential sector programs grows over the study horizon as program participation increases. Figure 37 shows the contribution from each modeled demand response program for the four considered scenarios in 2040. Two programs were cost effective and thus included in the economic and achievable scenarios – Smart Thermostats and Smart Water Heaters. In the Achievable scenarios, Smart Thermostats achieve the largest share of the demand response potential.

Traditional DLC programs are not cost effective given their higher switch and controller hardware costs. The analysis shows that demand response for residential HVAC unit loads could be more cost effectively managed with a Bring-Your-Own-Thermostat program format utilizing customer-purchased smart thermostat devices. This finding aligns with a nationally observable trend away from the older DLC technology and pager network communications protocols towards programs that use customer-purchased devices and device internet access for communication.

Although a less mature program model, Smart Water heater programs are also increasing in popularity in many jurisdictions nationwide. Some versions of these programs similarly use internet-based communications and would be the most cost effective for Tri-State. Water heaters with built-in grid connection technology are also becoming more widely available, thus eliminating the need for installation of a separate device. As this technology matures, Tri-State could likely develop a successful demand response program to control residential water heaters during peak periods.

**Figure 36. Residential Sector Demand Response Potential by Scenario by Year**

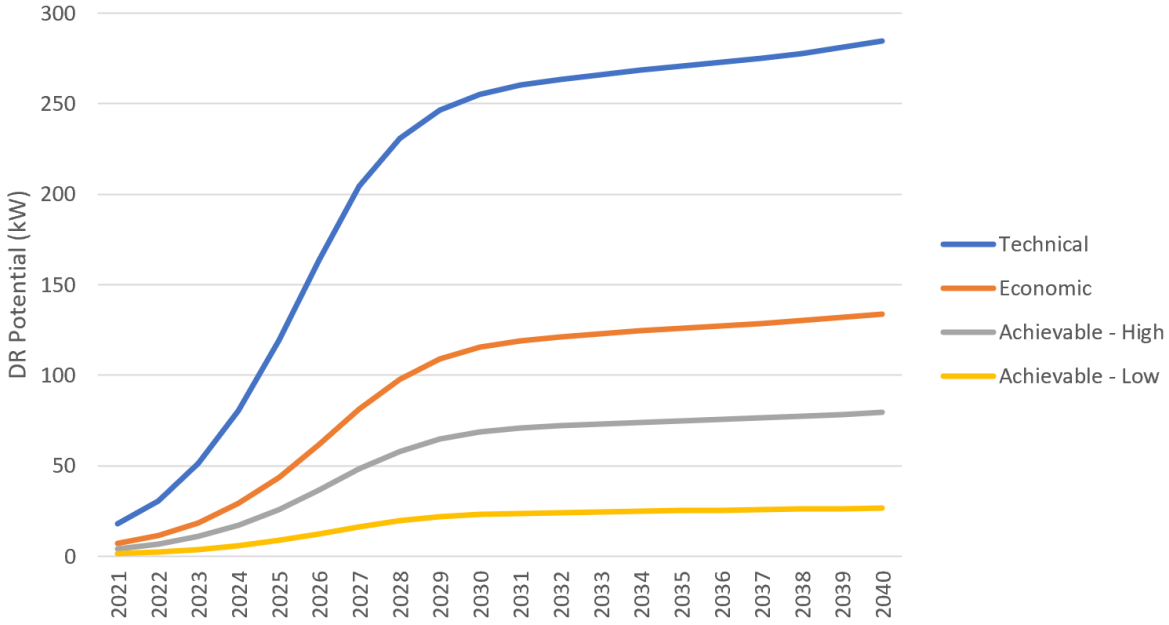
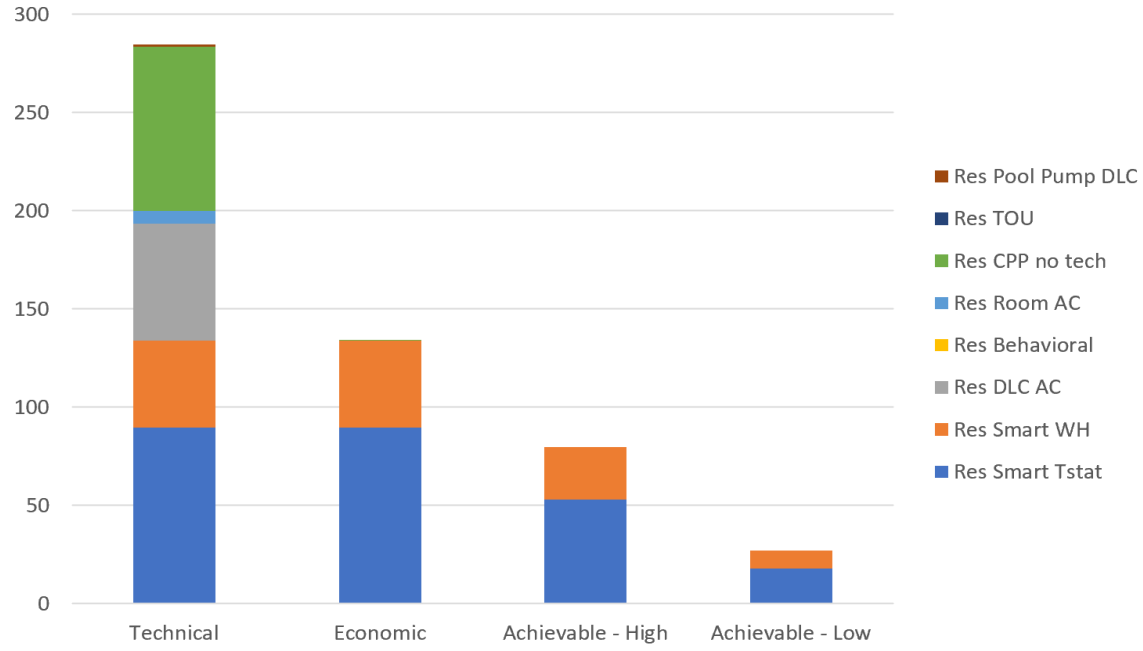



**Figure 37. Residential Sector Demand Response Potential by Program (2040)**



## 9.3. Irrigation Sector Demand Response Potential

Figure 38 shows how demand response potential for the irrigation sector programs grows over the study horizon as program participation increases. Figure 39 shows the each modeled demand response program's contribution to the four considered scenarios in 2040. Two programs were cost effective and therefore included in the economic and achievable scenarios – Direct Load Control and Critical Peak Pricing without Enabling Technology. In the Achievable scenarios, Direct Load Control achieves the largest share of the demand response potential.

Successful irrigation DLC programs are currently operational in regions similar to portions of Tri-State's territory, such as Idaho Power's Irrigation Peak Rewards program. That program is designed to target only customers with pumping demand greater than 75 horsepower, thereby focusing economic resources for maximum demand reduction. This analysis included eligibility rates for each region in Tri-State's territory to estimate the regional prevalence of large irrigation pumps. Mountain Colorado, for example, has a 0% eligibility rate because of presumed reliance on lower horsepower pumps for horizontal pumping.

**Figure 38. Irrigation Sector Demand Response Potential by Scenario by Year**

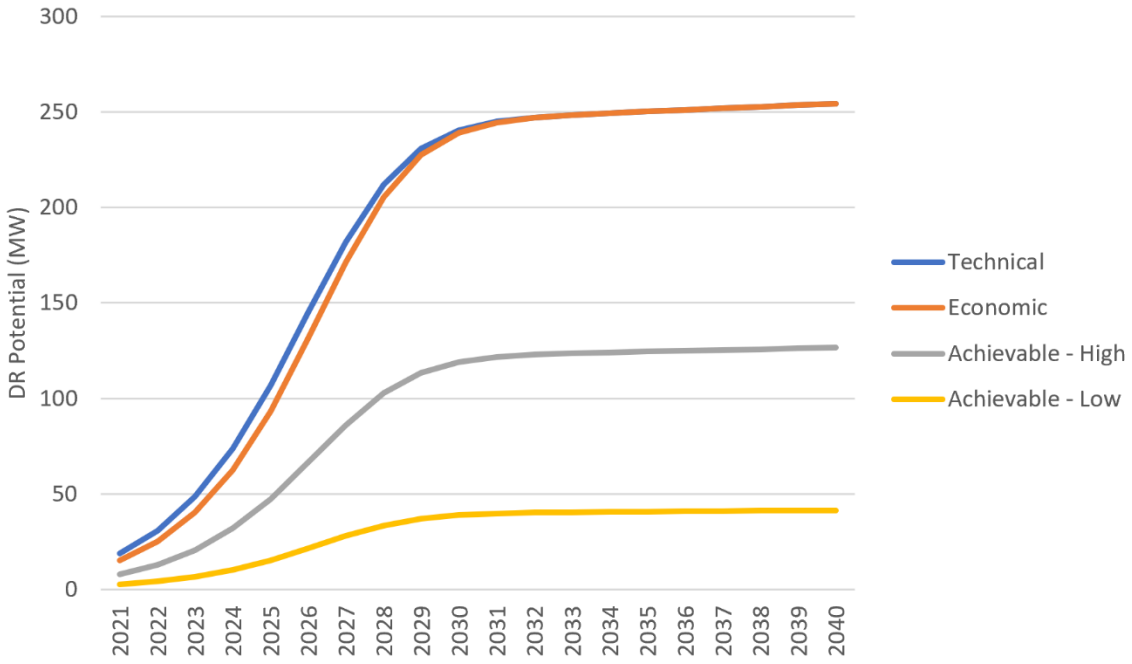
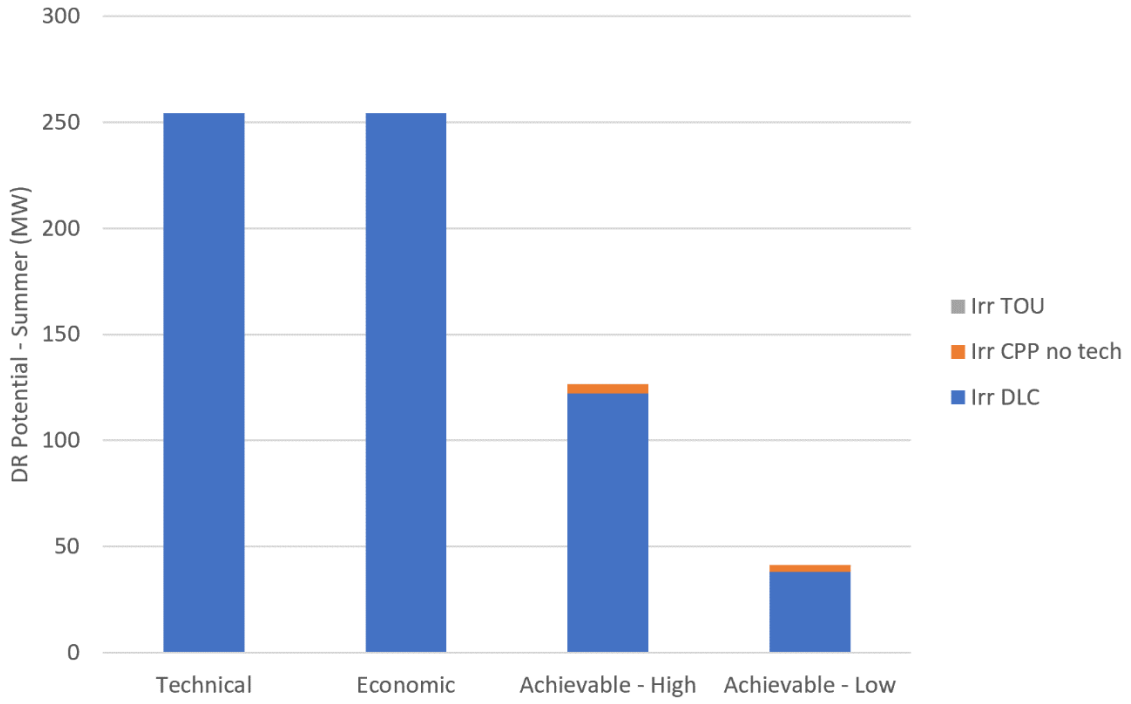


**Figure 39. Irrigation Sector Demand Response Potential by Program (2040)**




## 9.4. Commercial Sector Demand Response Potential

Figure 40 shows how demand response potential for irrigation sector programs grows over the study horizon as program participation increases. Figure 41 shows each modeled demand response program's contribution to the four considered scenarios in 2040. Three programs were cost effective and therefore included in the economic and achievable scenarios – Demand Bidding, Smart Thermostats, and Critical Peak Pricing without Enabling Technology. The Smart Thermostats program option was modelled as an extension of the residential Smart Thermostats program and assuming the residential program sector carries a majority of program set-up and administration costs.

Capacity bidding programs offer qualified businesses incentive payments for agreeing to reduce load (for example, lighting, HVAC, escalators/elevators, pumps or some manufacturing equipment) when an event is called. Third-party aggregators often manage these types of programs; thefore, this could be a strategy to overcome Tri-State's lack of direct access to end-users.

**Figure 40. Commercial Sector Demand Response Potential by Scenario by Year**

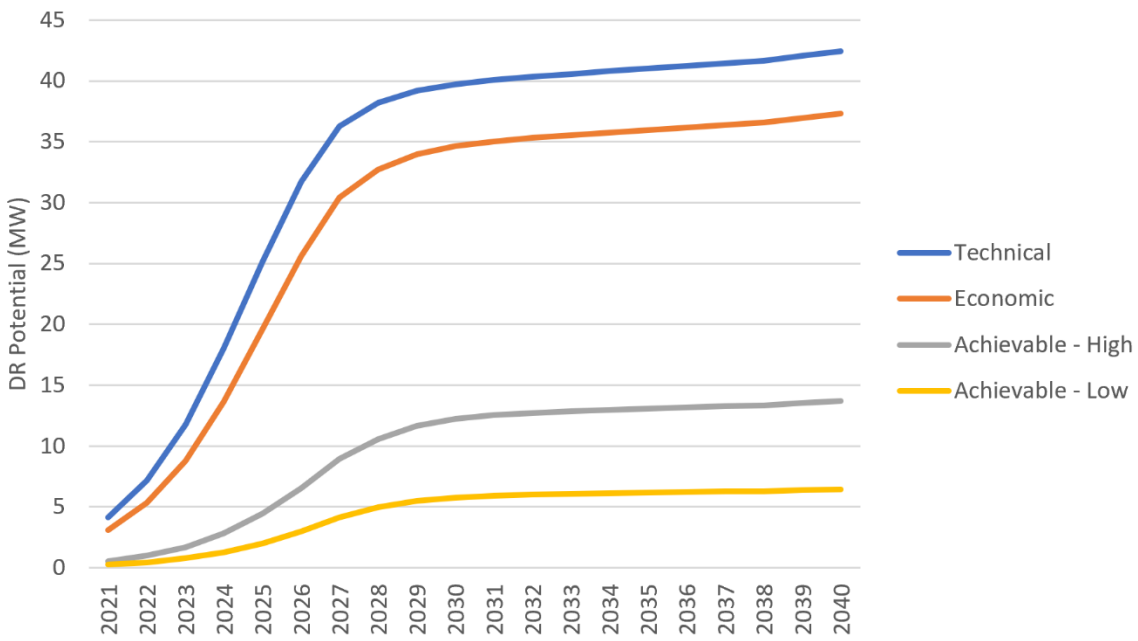
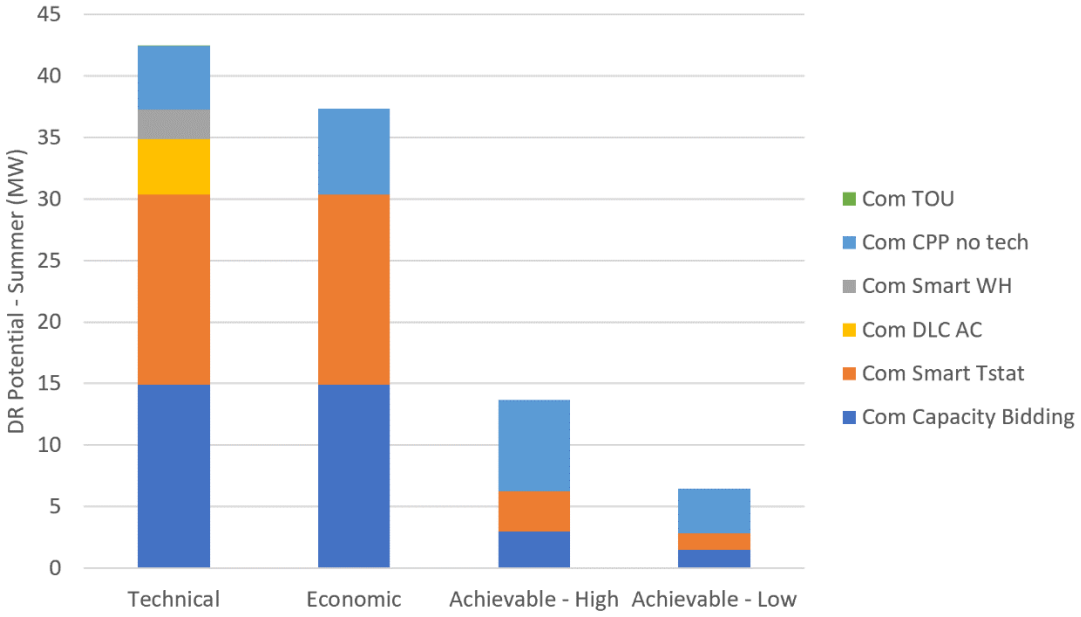



**Figure 41. Commercial Sector Demand Response Potential by Program (2040)**




## 9.5. Industrial Sector Demand Response Potential

Figure 42 shows how demand response potential for industrial sector programs grows over the study horizon as program participation increases. Figure 43 shows each modeled demand response program's

contribution to the four considered scenarios in 2040. Two programs are cost effective and therefore included in the economic and achievable scenarios – Capacity Bidding and Critical Peak Pricing without Enabling Technology.

As in the commercial sector, capacity bidding programs offer qualified businesses incentive payments for agreeing to reduce load (for example, lighting, HVAC, escalators/elevators, pumps or some manufacturing equipment) when an event is called. These types of programs are often managed by third-party aggregators, and thus could be a strategy to overcome Tri-State's lack of direct access to end-users.

**Figure 42. Industrial Sector Demand Response Potential by Scenario by Year**

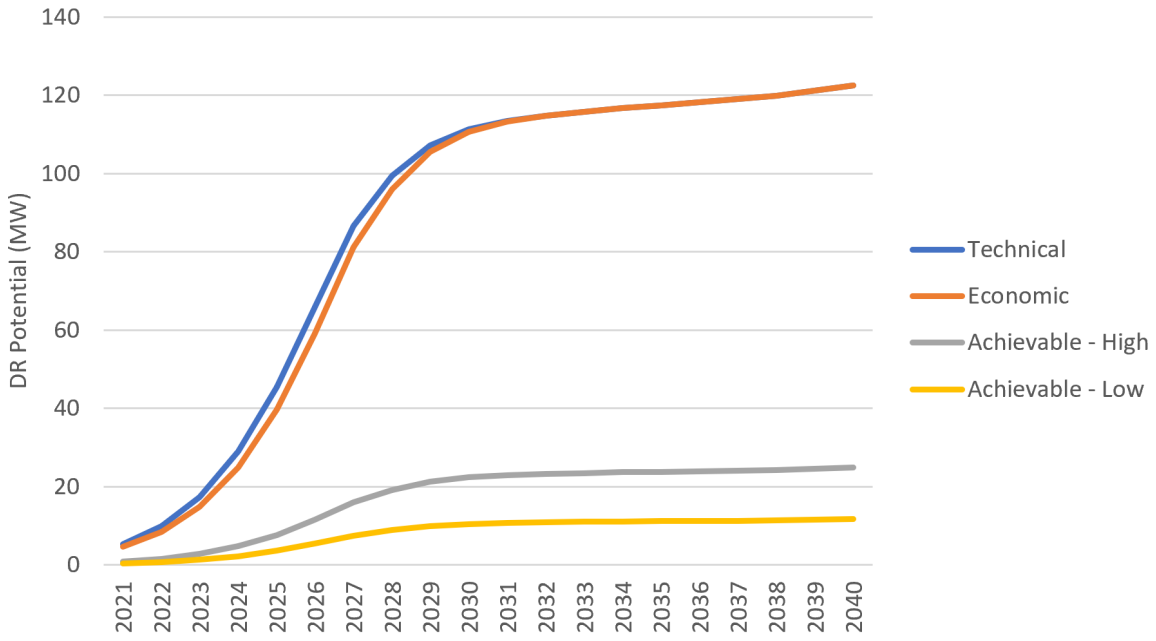
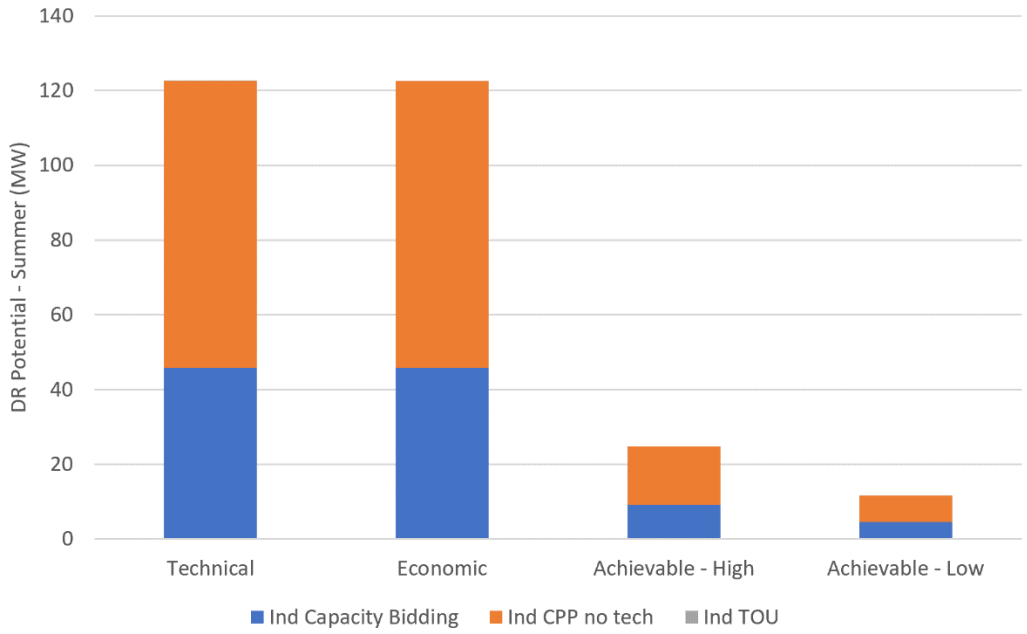


**Figure 43. Industrial Sector Demand Response Potential by Program (2040)**




# 10. BEHIND-THE-METER DISTRIBUTED ENERGY RESOURCE POTENTIAL STUDY FINDINGS

## 10.1. Overview

As discussed in Section 3, the Team assessed rooftop solar PV potential for the residential and non-residential sectors. The technical potential analysis considered the total rooftop area suitable for solar PV within Tri-State's territory and extrapolated potential solar generation based on solar system power density per square foot for each Tri-State region. The Team subsequently screened systems for cost effectiveness and adjusted potential accordingly followed by further adjustments using adoption curves to represent achievable potential.

The Team found no systems to be cost effective for the residential sector under any TRC scenario analyzed. The highest TRC ratio achieved under the residential sector was 0.45 which reflects capacity and $CO_2$ emissions benefits.

The non-residential sector's very large PV systems are marginally cost effective for specific scenarios. Of these scenarios, the Team found the presence of $CO_2$ emissions benefits to be crucial as no PV system analyzed surpassed a TRC of 1.0 without inclusion of these benefits.

## 10.2. Detailed Results

Table 33 and Table 34 summarize the solar PV cumulative annual potential estimated generation for the residential and non-residential sectors, respectively. Electric demand impacts are presented for each sector in Table 35 and Table 36. While technical potential represents 100% adoption for each year, economic and achievable potential reflect applied adoption rates across the study time horizon.

**Table 33. Cumulative Residential Generation Potential by Scenario by Time Horizon (MWh)**

| MILESTONE YEAR | TECHNICAL | ECONOMIC | ACHIEVABLE _MAX | ACHIEVABLE _AGG | ACHIEVABLE _MOD | ACHIEVABLE _LOW |
|---|---|---|---|---|---|---|
| 2021 (first year) | 2,548,130 | 0 | 0 | 0 | 0 | 0 |
| 2025 | 13,139,699 | 0 | 0 | 0 | 0 | 0 |
| 2030 | 27,290,122 | 0 | 0 | 0 | 0 | 0 |
| 2040 | 58,657,889 | 0 | 0 | 0 | 0 | 0 |

**Table 34. Cumulative Non-Residential Generation Potential by Scenario by Time Horizon (MWh)**

| MILESTONE YEAR | TECHNICAL | ECONOMIC | ACHIEVABLE MAX | ACHIEVABLE AGG | ACHIEVABLE MOD | ACHIEVABLE LOW |
|---|---|---|---|---|---|---|
| 2021 (first year) | 6,417,504 | 10,322 | 10,310 | 10,300 | 10,284 | 10,256 |
| 2025 | 33,037,716 | 141,370 | 139,829 | 138,809 | 137,108 | 134,198 |
| 2030 | 68,427,022 | 1,011,060 | 951,078 | 911,778 | 851,923 | 764,606 |
| 2040 | 146,160,272 | 5,512,777 | 4,705,933 | 4,254,001 | 3,661,295 | 2,952,911 |

The demand impacts presented in Table 35 and Table 36 reflect technical capacity based on operational capacity (based on installed nameplate) and coincident peak capacity. Economic and achievable scenarios reflect coincident peak capacity benefits.

**Table 35. Summary of Residential Solar PV Electric Demand Market Potential (MW)**

| MILESTONE YEAR | TECHNICAL DC CAPACITY | TECHNICAL PEAK CAPACITY | ECONOMIC | ACHIEVABLE MAX | ACHIEVABLE AGG | ACHIEVABLE MOD | ACHIEVABLE LOW |
|---|---|---|---|---|---|---|---|
| 2021 (first year) | 1,644 | 400 | 0 | 0 | 0 | 0 | 0 |
| 2025 | 1,747 | 425 | 0 | 0 | 0 | 0 | 0 |
| 2030 | 1,878 | 457 | 0 | 0 | 0 | 0 | 0 |
| 2040 | 2,141 | 521 | 0 | 0 | 0 | 0 | 0 |

**Table 36. Summary of Non-Residential Solar PV Electric Demand Market Potential (MW)**

| MILESTONE YEAR | TECHNICAL DC CAPACITY | TECHNICAL PEAK CAPACITY | ECONOMIC | ACHIEVABLE MAX | ACHIEVABLE AGG | ACHIEVABLE MOD | ACHIEVABLE LOW |
|---|---|---|---|---|---|---|---|
| 2021 (first year) | 4,139 | 1,106 | 2 | 2 | 2 | 2 | 2 |
| 2025 | 4,384 | 1,172 | 9 | 9 | 9 | 9 | 9 |
| 2030 | 4,686 | 1,252 | 49 | 45 | 42 | 37 | 31 |
| 2040 | 5,281 | 1,411 | 83 | 69 | 61 | 50 | 39 |

The cumulative residential generation potential under the technical scenario equates to 57% of the cumulative residential baseline load sales forecast for 2040 (see Table 37). Similarly, the non-residential cumulative generation represents 52% of the cumulative residential baseline load forecast for 2040 (see Table 38). Non-residential economic potential equates to 2.0% of the cumulative residential baseline load forecast for 2040 and ranges from 1.7% to 1.1% under the achievable potential scenarios.

**Table 37. Cumulative Residential Generation Potential as % of Baseline Forecast Sales by Year**

| MILESTONE YEAR | TECHNICAL | ECONOMIC | ACHIEVABLE MAX | ACHIEVABLE AGG | ACHIEVABLE MOD | ACHIEVABLE LOW |
|---|---|---|---|---|---|---|
| 2021 (first year) | 56.1% | 0 | 0 | 0 | 0 | 0 |
| 2025 | 56.3% | 0 | 0 | 0 | 0 | 0 |
| 2030 | 56.4% | 0 | 0 | 0 | 0 | 0 |
| 2040 | 56.5% | 0 | 0 | 0 | 0 | 0 |

**Table 38. Cumulative Non-Residential Generation Potential as % of Baseline Forecast Sales by Year**

| MILESTONE YEAR | TECHNICAL | ECONOMIC | ACHIEVABLE MAX | ACHIEVABLE AGG | ACHIEVABLE MOD | ACHIEVABLE LOW |
|---|---|---|---|---|---|---|
| 2021 (first year) | 53.9% | 0.1% | 0.1% | 0.1% | 0.1% | 0.1% |
| 2025 | 53.4% | 0.2% | 0.2% | 0.2% | 0.2% | 0.2% |
| 2030 | 53.1% | 0.8% | 0.7% | 0.7% | 0.7% | 0.6% |
| 2040 | 52.0% | 2.0% | 1.7% | 1.5% | 1.3% | 1.1% |

## 10.3. Technical DER Potential Findings

Overall, solar PV generation has the technical capability of providing over half of Tri-State's sales. However, this value varies considerably by region. Figure 44 and Figure 45 below illustrate cumulative PV generation in 2040 compared to cumulative 2040 sales. For both the residential and non-residential

sectors, PV generation is well below total sales for each region with the exception of Northern New Mexico (for residential) and Southern New Mexico. New Mexico's PV generation exceeds sales due to a high solar irradiance which improves solar efficiency, a relatively high number of buildings, and relatively low energy consumption on average.

**Figure 44. 2040 Cumulative Residential PV Generation vs Sales by Region**

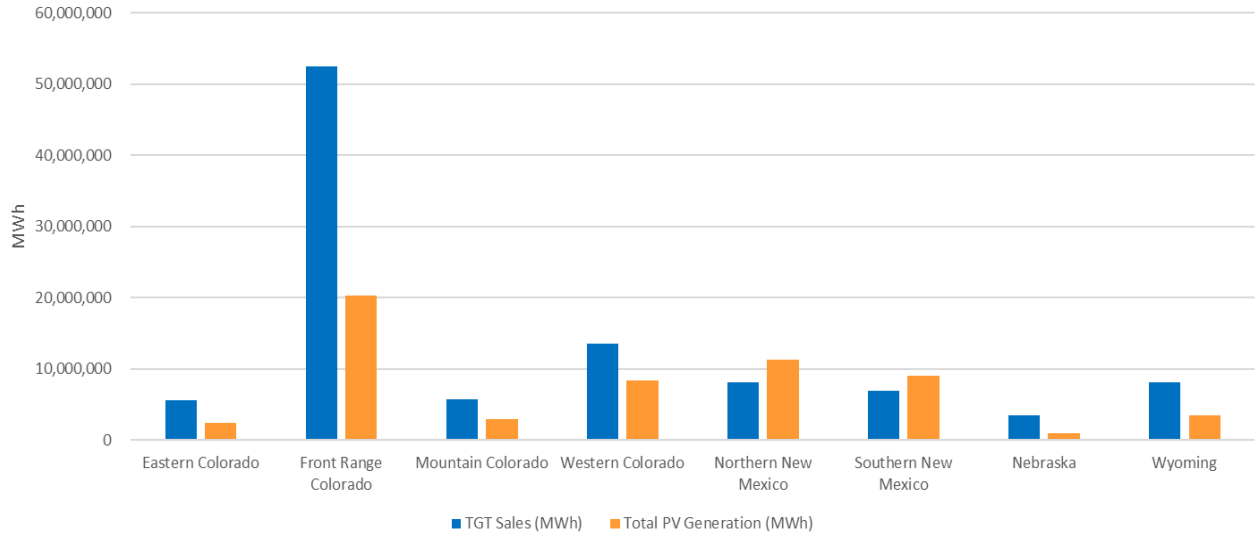
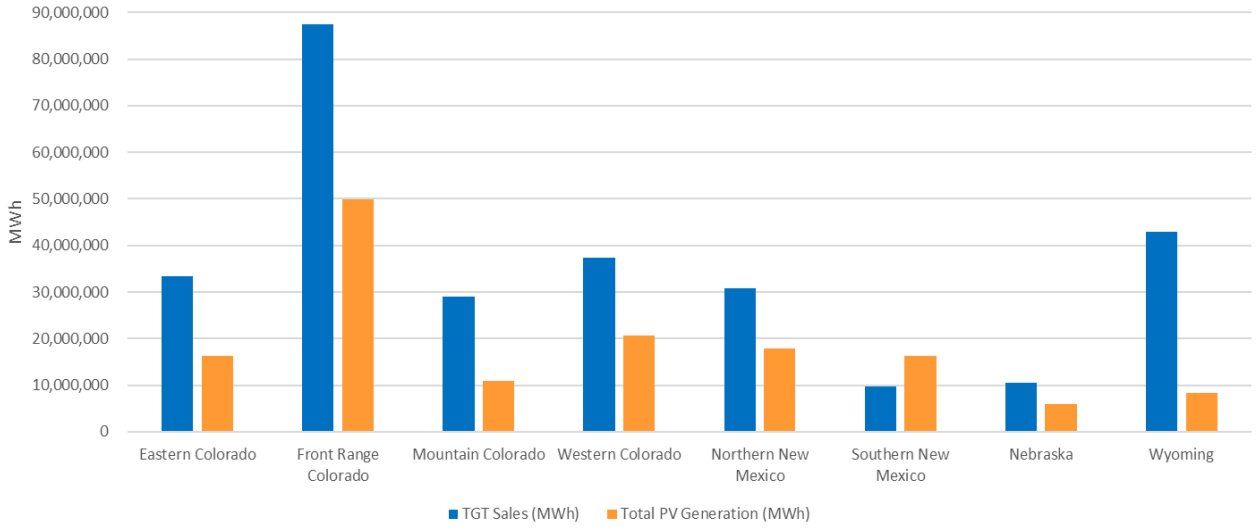



**Figure 45. 2040 Cumulative Non-Residential PV Generation vs Sales by Region**




## 10.4. Economic and Achievable DER Potential Findings

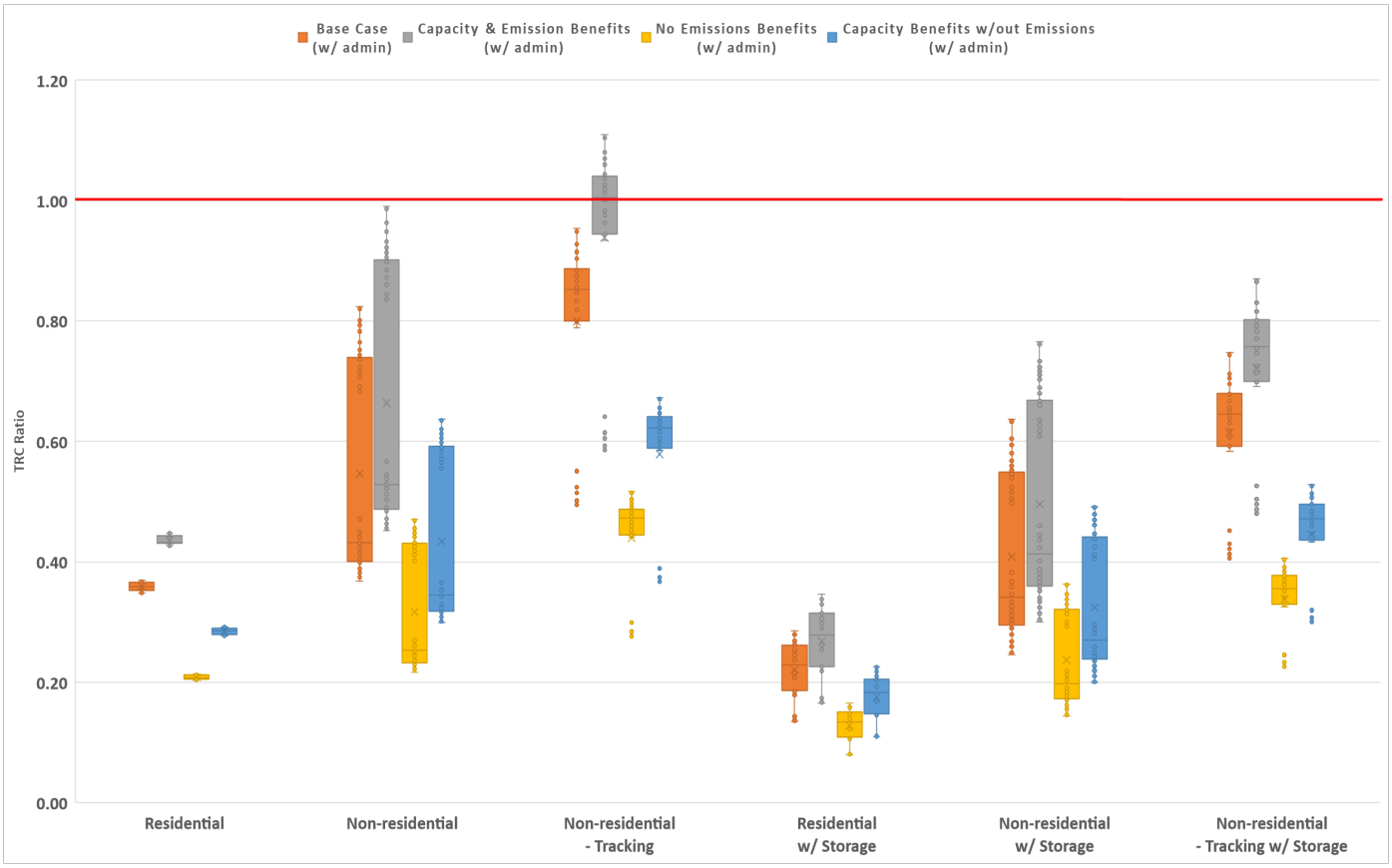
The Team screened economic potential using a TRC hurdle of 1.0 with the inclusion of $CO_2$ emission benefits based on the social cost of carbon of $46/ton and administrative costs of $0.05/kWh. However,

to understand the sensitivity of various benefit parameters, the team modeled cost effectiveness for multiple scenarios that included various combinations of benefits. Scenarios reviewed included:

- Base case
  - Inclusive of $CO_2$ emission reduction benefits
- Capacity and emission benefits
  - Base case inclusive of benefits resulting from reduced capacity needs
  - Inclusive of $CO_2$ emission reduction benefits
- No emissions benefits
  - Base case exclusive of $CO_2$ emission reduction benefits
- Capacity benefits without emissions benefits
  - Base case inclusive of benefits resulting from reduced capacity needs
  - Exclusive of $CO_2$ emission reduction benefits

Figure 46 illustrates the results and sensitivities of the solar PV cost effectiveness under each of these scenarios for various categories of solar PV systems included in the potential study. Only one scenario yields TRC ratios that exceed 1.0 – non-residential tracking systems assuming the presence of capacity and $CO_2$ emission benefits benefits. Also noted is any scenario excluding $CO_2$ emission benefits results in all solar system configurations analyzed to fail pass cost effectiveness.

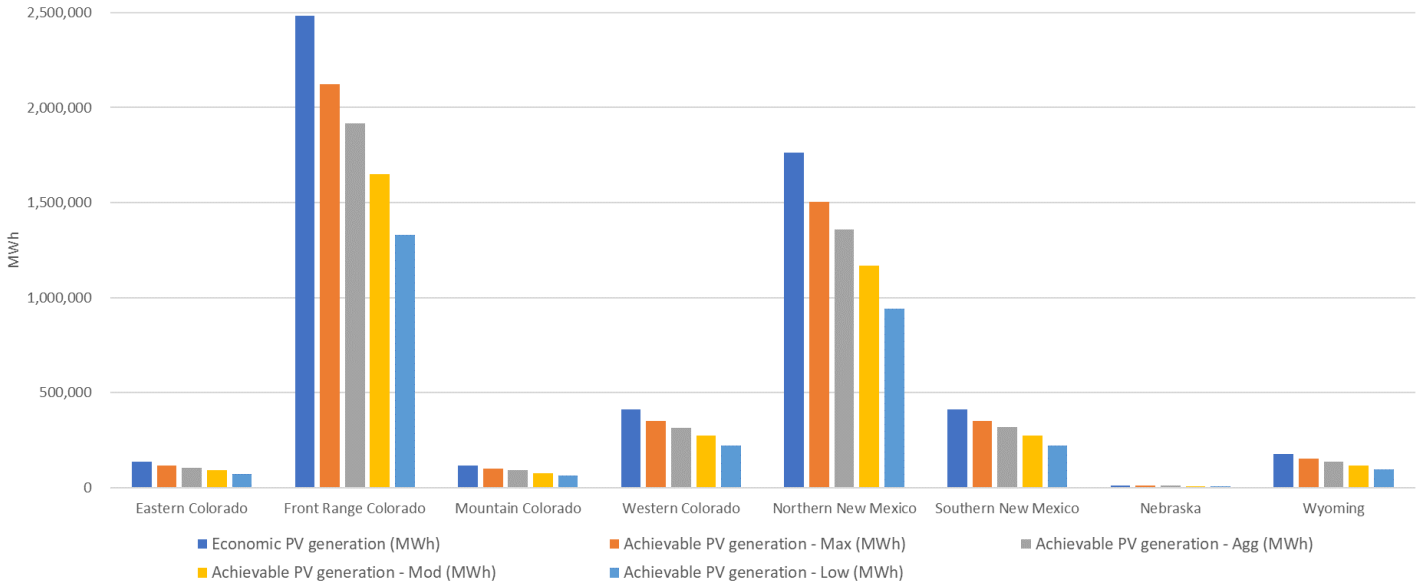
**Figure 46. Solar PV TRC Ratios - Multiple Scenarios**




Based on the cost effectiveness analysis, the Team modeled economic and achievable potential based on the sole cost effective scenario – non-residential tracking solar systems with capacity and emission benefits. Twenty two solar PV system configurations (9% of all tested measure permutations) passed cost effectiveness including tracking systems varying in size from 250 kW to 2000 kW system capacity. These passing measures have an average TRC of 1.04. This scenario, however, is not applicable throughout the Tri-State territory insofar as capacity constraints are not expected until 2027 (and therefore capacity benefits would not be realized until that time) and carbon benefits are only applicable to Colorado regions (at the time of report publication). Regardless, for the purposes of this report, the Team opted to model economic and achievable potential for all regions in order to inform Tri-State of how solar adoption may occur throughout its territory.

The results of the economic and achievable potential are presented below in Figure 47. Economic and achievable potential is limited due to the small number of solar systems that pass cost effectiveness and due to the physical requirements of these systems – tracking systems are considered ground-mounted for this analysis and therefore are only applicable to sites that are expected to have sufficient land space to host these systems and the system does not generate more energy than the site consumes. Based on these constraints, the team estimated 66 eligible sites across Tri-State's territory for the economic scenario. The number of eligible systems decreases for each achievable potential scenario as solar system payback time increases.

**Figure 47. 2040 Cumulative Non-Residential Economic and Achievable Potential by Region**




As illustrated in Figure 47, the highest concentration of eligible sites, and thereby the highest potential, are in the Front Range and Northern New Mexico regions. However, as noted earlier, carbon emission benefits at the time of this report publication are not currently a quantifiable benefit in New Mexico, Wyoming, or Nebraska and therefore this reported economic and achievable potential should be considered with that perspective.

# 11.KEY FINDINGS

At present Tri-State and its member cooperatives deliver some energy efficiency and DR programs, and no DER programs, to their customers. Even with low avoided energy cost benefits for DSM programs within Tri-State's service territory this study identifies significant cost-effective opportunities for energy and demand savings for energy efficiency programs. There are also opportunities for DR programs, but in some cases those program require long term operation to provide cost-effectiveness. DER programs are generally not cost-effective except for larger systems in specific regions. Key findings and observations related to each of these resources is summarized below. It should be noted that the results of this study and the findings presented here are uncertain to a degree and are sensitive customer adoption of DSM intervetions. Furthermore, the dynamic relationship between Tri-State and the member co-ops presents instrinsic challenges to the seamless implementation of DSM programs. These variables should be take into account when considering the results of this study.

## 11.1. Energy Efficiency

In 2018, Tri-State cooperative members acquired roughly 30 GWh of energy efficiency savings (~0.2% of baseline energy load)[17]. This suggests that Tri-State's members are currently operating programs somewhere between the Achievable-Low and Achievable-Moderate scenarios, which identified energy savings of 27 GWh and 38 GWh respectively in 2021. With coordinated efforts among cooperative members the long-term market opportunity for cost-effective energy efficiency savings in the region served by Tri-State is considerably higher; the average annual savings potential is 115 GWh over the study's 20-year time horizon for the Achievable-Moderate scenario. Additional key findings within the energy efficiency assessment include:

- 20-year average annual energy savings are just under 115 GWh (0.66% of baseline energy load) at a total program cost of $24M per year ($212/MWh acquired).
- 20-year levelized cost of energy to acquire all energy savings is $21.55/MWh.
- While the industrial sector represents the largest market opportunity (43% of 20-year potential), the residential sector represents the biggest opportunity (35% of potential) compared to its load share (28% of load).
- The commercial sector holds the most cost-effective savings opportunities with a TRC of 1.93 and average 20-year acquisition cost of $171/MWh.
- Pumps (primarily within the industrial sector) represent the largest end-use opportunity across the portfolio at 25% of 20-year cumulative energy savings – much of this opportunity resides with several large Liquid Mining and Pipeline Transportation customers.
- Even with rapid market transformation to LEDs for A-lamp bulbs, there is still considerable savings opportunities in the commercial lighting (21% of potential) and Residential lighting (19% of potential) end-uses – these end-uses are also among the most cost effective with acquisition costs of $150/MWh and $200/MWh respectively.

[17] Tri-State Generation and Transmission, Inc. 2018 Annual Report. (p. 12).

- HVAC measures account for 18% of savings potential – though are relatively expensive with an average acquisition cost of roughly $275/MWh.
- With zero capacity benefits in the first seven years, Home Energy Reports did not pass the study's TRC cost-effectiveness screen until 2028; after which the measure becomes a major opportunity contributing to almost 6% of portfolio savings potential.
- High/medium bay linear lamp and fixture conversions to LED technology represents more than 60% of cumulative energy savings potential in the commercial sector by 2040.
- Non-EISA compliant light bulbs contribute more than 45% to cumulative energy savings potential by 2040 in the residential sector.
- Upgrading existing air source heat pumps to higher efficiency models represent more than 6% of cumulative energy savings potential by 2040 in the residential sector.

## 11.2. Demand Response

The analysis finds that a Tri-State portfolio of demand response programs could cost effectively contribute 86 MW of demand curtailment during the summer peak window by the end of the 20-year time horizon. This result (the Achievable-Low scenario) assumes conservative realistic participation rates across Tri-State's territory. Additional key findings from the demand response potential analysis include:

- High levels of investment in marketing and incentives could yield up to 245 MW of potential (Achievable-High scenario).
- Potential reduction in portfolio-level baseline forecast demand ranges from 2.4% (Achievable-Low) to 6.9% (Achievable-High).
- The residential and irrigation sectors hold the greatest potential for demand response program savings.
- In general, the Direct Load Control program model holds the greatest potential for savings. Among the two Achievable scenarios the most promising program models within each each sector are:
    - Residential: Smart Thermostats and Smart Water Heaters
    - Commercial sector: Critical Peak Pricing and Smart Thermostats
    - Industrial: Critical Peak Pricing
    - Irrigation: Direct Load Control

## 11.3. Behind-The-Meter Distributed Generation

We analyzed potential for rooftop solar PV across Tri-State's territory for both the residential and non-residential sectors. Ultimately we found rooftop solar PV to not be cost effective for the residential sector. The non-residential sector is cost effective for very large ground-mounted tracking solar arrays when including key benefits of capacity and emission benefits. Additional findings from the distributed energy resource potential analysis include:

- Technical potential solar generation for both residential and non-residential sectors can equate to just over half of total sales.
- No residential solar PV measures pass cost effectiveness under any benefit-cost scenario analyzed in the study.
- The sole cost effective scenario includes both capacity benefits and $CO_2$ emissions benefits. Just 9% of analyzed measure permutations pass this cost effectiveness scenario and are characterized as non-residential ground-mounted tracking systems varying from 250 kW to 2000 kW system capacity. These system measures have an average TRC of 1.04.
- Cumulative non-residential economic potential solar PV generation equates to 2.0% of 2040 cumulative sales; achievable potential solar PV generation equates to 1.7% - 1.1% of 2040 cumulative sales. It is noted that while these potential savings reflect the entire Tri-State territory, the sole cost effective scenario is not applicable to regions outside of Colorado as emissions are not a quantifiable benefit at the time of this report publication.

BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

| | |
|---|---|
| Federal Power Act Section 202(c) | ) |
| Emergency Order: Tri-State | ) |
| Generation and Transmission | ) |
| Association, Platte River Power | ) |
| Authority, Salt River Project, | ) |
| PacifiCorp, and Xcel Energy | ) |

Exhibit to
Motion to Intervene and Request for Rehearing and Stay of
Public Interest Organizations

Exhibit 2-50:
Insgold 2023 ERP Direct Testimony

**BEFORE THE PUBLIC UTILITIES COMMISSION**
**OF THE STATE OF COLORADO**

**PROCEEDING NO. 23A-____E**

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**APPLICATION OF TRI-STATE GENERATION AND TRANSMISSION ASSOCIATION, INC. FOR APPROVAL OF ITS 2023 ELECTRIC RESOURCE PLAN**

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# DIRECT TESTIMONY AND ATTACHMENTS OF BARRY W. INGOLD ON BEHALF OF TRI-STATE GENERATION AND TRANSMISSION ASSOCIATION, INC.

**December 1, 2023**

Colorado PUC E-Filings System

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## ATTACHMENTS

| | |
|---|---|
| BWI-1 | Statement of Qualifications for Barry W. Ingold |

## I. INTRODUCTION, QUALIFICATIONS, AND PURPOSE OF TESTIMONY

**Q: PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.**

A: My name is Barry W. Ingold. My business address is 1100 West 116th Avenue, Westminster, CO 80234.

**Q: BY WHOM ARE YOU EMPLOYED AND IN WHAT CAPACITY?**

A: I am employed by Tri-State Generation and Transmission Association, Inc. ("Tri-State") as Chief Operating Officer.

**Q: ON WHOSE BEHALF ARE YOU TESTIFYING IN THIS DOCKET?**

A: I am testifying on behalf of Tri-State.

**Q: HAVE YOU PREPARED A STATEMENT OF YOUR EXPERIENCE AND QUALIFICATIONS?**

A: Yes. My Statement of Qualifications is attached to my testimony as **Attachment BWI-1**.

**Q: PLEASE SUMMARIZE YOUR BACKGROUND AND EXPERIENCE IN THE ELECTRICITY UTILITY INDUSTRY.**

A: I have 26 years of experience in the electric utility industry. In my present position, I am responsible for managing Tri-State's generation and transmission operations. This includes all capital budget and construction projects for Tri-State's generation and transmission facilities. Prior to joining Tri-State, I was an Application Control Engineer and Project Manager for Honeywell International, Inc., a global provider of control solutions. In addition to my years of industry experience, I served for thirteen years in the submarine force of the United States Navy. I then transitioned to the Navy Reserve where I served for an additional thirteen years, during which

time I held command of five Navy Reserve Detachments. I attained the rank of Captain prior to retiring from the United States Navy. I hold a Bachelor's degree in Marine Engineering and Marine Transportation from the United States Merchant Marine Academy, a Master's degree in Mechanical Engineering from the Naval Postgraduate School, and a Master's degree in Business Administration from Arizona State University.

**Q: WHAT IS THE PURPOSE OF YOUR TESTIMONY IN THIS PROCEEDING?**

A: My Direct Testimony addresses certain technical and operational assumptions regarding Tri-State's owned and contracted thermal (coal and natural gas) resources relied upon as inputs to the 2023 Electric Resource Plan ("ERP"). I also address assumptions and analysis regarding the potential for new or expanded owned or contracted thermal resources during the resource acquisition period ("RAP").

**Q. ARE YOU SPONSORING ANY ATTACHMENTS AS PART OF YOUR TESTIMONY?**

A. Yes, as part of my Direct Testimony, I am sponsoring the following attachments:

- Attachment BWI-1: Statement of Qualifications for Barry W. Ingold

## II. EXISTING COAL RESOURCES

**Q. WHAT IS THE PURPOSE OF THIS SECTION OF YOUR TESTIMONY?**

A. In this section of my Direct Testimony, I identify and describe Tri-State's current, existing coal-fired fleet, including forecasted operations and emissions reductions, during the RAP.

**Q: PLEASE BRIEFLY DESCRIBE THE CURRENT COAL-FIRED GENERATION**

**RESOURCES IN TRI-STATE'S GENERATION FLEET.**

A. Tri-State maintains a stake in three coal-fired generation facilities across its system footprint. These include:

- Craig Station (Units 1, 2, and 3), located in Colorado, with net generating capacity of 427 MW, 410 MW,[1] and 448 MW, respectively. Tri-State is the operator of Craig Station.
- Laramie River Station ("LRS"),[2] located in Wyoming, with net generating capacity of 1700 MW. LRS, and associated transmission, make-up the Missouri Basin Power Project ("MBPP"). Basin Electric Power Cooperative is the operator of the MBPP.
- Springerville Unit 3 ("SPV 3"), located in Arizona (primarily serving Tri-State's New Mexico load), has a net generating capacity of 419 MW. Tucson Electric Power Company is the operator of SPV 3.

**Q. WHERE DOES TRI-STATE SECURE ITS COAL SUPPLY FOR THESE GENERATION RESOURCES?**

A. Coal is supplied to Tri-State's fleet as follows:

- Craig Station: Colowyo Mine supplies coal for Tri-State and Public Service Company of Colorado's ("Public Service") portion of Craig Station. Trapper Mine supplies coal for the other three Yampa Partners'[3] portion of Craig

[1] Tri-State's net share of Craig 1 is 102 MW and Craig 2 is 98MW.
[2] LRS is a jointly owned unit under the Missouri Basin Power Project ("MBPP"). Tri-State is an MBPP participant with a 28.5 percent (484 MW) share and receives power from LRS 2 and LRS 3 due to their location in the western interconnection.
[3] Platte River Power Authority ("PRPA"), Salt River Project ("SRP"), and PacifiCorp.

Station. Unit 3 uses coal supply from only Colowyo, while Units 1 and 2 use a coal supply split from Trapper and Colowyo, with Trapper supplying a majority of the fuel for those two units.

- LRS: The MBPP procures and delivers coal from the Powder River Basin on behalf of the MBPP participants.
- SPV 3: Tri-State contracts with Peabody COALSALES, LLC, and the BNSF Railway Company to procure and deliver coal from the Powder River Basin to SPV 3.

The latest coal price forecast is a financial input to the 2023 ERP Phase I modeling and is identified in **Attachment B** ~~of the ERP Report (**Attachment LKT-1**).~~ LKT-7

**Q: HOW ARE THESE UNITS FORECASTED TO OPERATE DURING THE RAP?**

A: As further discussed within the Direct Testimony of Ms. Tiffin, Craig Station will conclude operations in 2028; and, if New ERA funding is received as requested, SPV 3 will retire in 2031, subject to reaching agreement with the applicable parties. LRS will continue its operations as it has previously, subject to applicable federal and state regulations.

**Q: PLEASE DESCRIBE TRI-STATE'S GOALS AND ACHIEVEMENTS RELATED TO EMISSIONS REDUCTIONS FROM THE USE OF COAL-FIRED GENERATION.**

A: Under Tri-State's Responsible Energy Plan ("REP"), we eliminated carbon emissions from Tri-State-owned coal generation in New Mexico in 2020. In Colorado, by 2030, we are targeting a 100 percent reduction in carbon emissions from Tri-State-owned coal generation. Additionally, by 2030, our goal is for 70

percent of the electricity our Members use system-wide to come from clean sources.

Additionally, under the 2020 ERP Phase I Settlement Agreement in Proceeding No. 20A-0528E, Tri-State committed that going forward, it will operate its system in a manner that achieves an 80 percent reduction in greenhouse gas ("GHG") emissions related to Tri-State's wholesale sales of electricity in Colorado in 2030.[4] As described by Ms. Tiffin in her Direct Testimony, all of the 2023 ERP Phase I scenarios were modeled in alignment with these REP and ERP commitments, with any modifications identified in **Attachment ~~B-3~~** ~~of the ERP Report (**Attachment LKT-1**).~~ LKT-10

Emissions and water use rates for each generator are identified in **Attachment ~~B~~** ~~of the ERP Report (**Attachment LKT-1**).~~ LKT-7

**a. <u>Craig Station</u>**

**Q: DOES TRI-STATE'S COAL-FIRED GENERATION FACILITY LOCATED IN COLORADO HAVE A FIRM RETIREMENT DATE?**

A: Yes. In January 2020, Tri-State voluntarily announced the planned retirement of all of Craig Station, including all three units, by 2030. The Craig Station units' closure dates are also identified in Colorado Regulation No. 23 Regional Haze Limits that were adopted by the Colorado Air Quality Control Commission ("AQCC") and made effective by publication in the Colorado Register on February

[4] 2020 ERP Phase I Settlement Agreement, Section 3.3.5. states: "Tri-State also agrees that, going forward, it will operate its system in a manner that achieves, at a minimum, with respect to its APCD-verified 2005 Baseline, an eighty percent (80%) reduction in GHG emissions related to Tri-State's wholesale sales of electricity in Colorado in calendar-year 2030 ("the 2030 Emissions Reduction").

14, 2021, as discussed further in Mr. Berger's Direct Testimony. Within Decision No. C23-0437 in Proceeding No. 20A-0528E, the Commission ordered Tri-State to evaluate alternative retirement dates for Craig 3 within the 2023 Phase I ERP modeling assumptions and practices to analyze the benefits and costs associated with various retirement dates, including economically optimal retirement dates as part of its Direct Case.[5] Pursuant to Decision No. C23-0437, Tri-State has reflected this directive within the 2023 ERP Phase I modeling as further outlined within the Direct Testimony of Lisa K. Tiffin and in the scenario assumptions identified in **Attachment ~~B-3~~** LKT-10 of the ERP Report (**~~Attachment LKT-1~~**). The retirement dates considered for Craig Unit 3 provide time for Tri-State to work with the State of Colorado to complete and begin to implement a transition plan for those employees and communities impacted by the closure of Craig Station.

**Q: WHAT IS THE STATUS OF TRI-STATE'S EFFORTS IN ENSURING A JUST TRANSITION FOR THE CRAIG COMMUNITY?**

A. There are two elements to the Just Transition effort. The first being a Workforce Transition Plan, which was submitted to the Colorado Office of Just Transition ("OJT") in December 2022, pursuant to the 2020 ERP Phase I Settlement Agreement, Section 3.12.1. As part of the workforce transition, Tri-State also executed a Letter of Agreement ("LOA") with IBEW Local 111 that outlines the manner in which employees will be affected as part of the closure of Craig Station. The second component of the just transition is community assistance. Tri-State's

[5] Decision No. C23-0437, at ¶ 77 (Proceeding No. 20A-0528E).

community assistance approach will be informed by the Informational Community Assistance Plan ("ICAP") under development by Tri-State, OJT, the City of Craig, Moffat County, the Colorado Energy Office, and the Office of the Utility Consumer Advocate, led by a third-party facilitator. The ICAP is planned to be complete in June 2024; it will be filed on an informational basis in the 2020 ERP proceeding, as identified in the 2020 ERP Settlement Agreement. Following ICAP completion, Tri-State will review the areas of assistance of greatest interest to the community identified in the ICAP, determine a financially feasible approach to community assistance, and make a recommendation for Tri-State Board approval by Q1 2025. These Just Transition plans are further discussed in the Direct Testimony of Mr. Orvis.

**Q: WHAT APPROACH IS TRI-STATE TAKING TO CAPITAL AND OPERATIONAL INVESTMENTS FOR CRAIG STATION OVER THE REMAINING LIFE OF THE PLANT?**

A: Tri-State's investments in Craig Station are being appropriately limited to only actions necessary for ensuring safe operations and regulatory compliance, given the impending retirement of these units.

**b. LRS**

**Q: PLEASE IDENTIFY THE KEY OPERATIONAL CONSIDERATIONS FOR LRS IN THE 2023 ERP.**

A: Tri-State is a participant in the MBPP, with a 28.5 percent (484 MW) share. Tri-State receives a portion of LRS generation and transmission capacity through its MBPP contract. Tri-State has a contractual obligation to pay its share of LRS

MBPP costs through the plant's full useful life. Tri-State does not have unilateral decision authority regarding LRS operations.

**c. SPV 3**

**Q: IDENTIFY THE KEY OPERATIONAL CONSIDERATIONS FOR SPV 3 IN THE 2023 ERP.**

A: First, Tri-State is not a joint owner of the Springerville plant and is not the plant operator. Tucson Electric Power ("TEP") is the facility operator and owner of SPV Units 1 and 2 and Salt River Project ("SRP") is the owner of SPV 4. Second, Tri-State is the majority equity owner of the partnership that indirectly owns SPV 3; and one hundred percent of SPV 3 is leased by Tri-State. Third, Tri-State supplies 100 MW of unit contingent capacity from SPV 3 to a third-party offtaker, SRP, under a power purchase agreement ("PPA") that extends through summer 2036. Fourth, certain common facilities and operational and maintenance costs are shared across the four SPV units. TEP has indicated Unit 1 will retire at the end of 2027 and Unit 2 will retire after the summer of 2032.[6] SPV 3 operational and financial assumptions reflected in 2023 ERP Phase I modeling are provided in **Attachment ~~B~~** LKT-7 ~~of the ERP Report (**LKT-1**).~~

**Q: HAS TRI-STATE INFORMED SRP, TEP, AND THE OTHER EQUITY OWNER OF THE IRA SCENARIO RESULTS FOR SPV 3?**

A: Yes. Tri-State has informed these parties of the 2031 retirement date for SPV 3, subject to New ERA funding and reaching agreement with the applicable parties.

[6] https://www.tep.com/wp-content/uploads/TEP-2020-Integrated-Resource-Plan-Lo-Res.pdf (page 93).

Ms. Tiffin's Direct Testimony further discusses Tri-State's approach to implementation of the IRA Scenario resource plan.

## III. EXISTING NATURAL GAS RESOURCES

**Q. WHAT IS THE PURPOSE OF THIS SECTION OF YOUR TESTIMONY?**

A. In this section of my Direct Testimony, I identify and describe both Tri-State's current natural gas resources, as well as a new gas unit addition planned during the RAP.

**Q: PLEASE IDENTIFY AND BRIEFLY DESCRIBE THE CURRENT NATURAL GAS GENERATION RESOURCES IN TRI-STATE'S GENERATION FLEET.**

A: Tri-State fully owns and operates four natural gas generation resources across its system footprint in Colorado and New Mexico. These resources are identified in **Attachment ~~C-3~~** LKT-17 of the ERP Report (**~~Attachment LKT-1~~**) and include both combined and simple cycle generating units. Specifically, the fleet includes simple cycle units that have dual-fuel capabilities.

**Q: PLEASE DESCRIBE THE RELIABILITY BENEFITS OF OPERATING NATURAL GAS FACILITIES IN CONCERT WITH THE INCREASING DEPLOYMENT OF RENEWABLE RESOURCES.**

A: As fully dispatchable resources, gas resources allow for response to gradual or abrupt changes in energy supply, within unit ramping characteristics, that may arise from the increasing deployment of renewables, which assists in maintaining system balance.

## IV. NEW COMBINED CYCLE NATURAL GAS PLANT

**Q: WHAT DOES THE 2023 ERP PHASE I IRA SCENARIO INDICATE REGARDING**

**THE NEED FOR AN ADDITIONAL GAS RESOURCE?**

A: The IRA Scenario, which is Tri-State's preferred resource plan, selects a 290 MW natural gas combined cycle ("NGCC") resource in 2028 located in electrically western Colorado.[7] The IRA Scenario also adds carbon capture and sequestration ("CCS") to the combined cycle resource in 2031. The technical, operational, and financial assumptions modeled for the generic natural gas with CCS (NGCC with CCS) facility can be found in **Attachment ~~C-2~~** LKT-16 of the ERP Report (**~~Attachment LKT-1~~**).

**Q: WHAT KEY BENEFITS DOES A COMBINED CYCLE GAS RESOURCE ADD TO TRI-STATE'S GENERATION FLEET?**

A: As described above, natural gas resources provide a complementary and necessary reliability backbone for meeting load needs with an increasing amount of intermittent renewable resources. As identified in the ERP Report (**Attachment LKT-1**), 64 percent of Tri-State's system energy needs are forecasted to be served by renewable energy in 2030, even with the addition of this new gas unit. Also, firm capacity to deliver energy when called upon is critical to maintaining reliability across the Tri-State system, especially during prolonged periods of low or no solar and wind production.

**Q: DID TRI-STATE EXPLORE ALTERNATIVE NATURAL GAS EXPANSION SOLUTIONS INSTEAD OF A NEW RESOURCE ADDITION?**

A: Yes. Tri-State evaluated two alternative options for obtaining the additional natural

[7] See planning region definitions in the ERP Report (LKT-1).

gas capacity needed to maintain system reliability: (1) contracting for the capacity through near-term power purchase agreements ("PPAs"), and/or (2) expanding the capacity of Tri-State's existing natural gas generation facilities. Ms. Hunter's Direct Testimony addresses the first alternative and I address the second, along with Mr. Berger.

**Q: COULD TRI-STATE EXPAND THE CAPACITY OF ITS EXISTING NATURAL GAS GENERATORS TO MEET THE NEED FOR A NATURAL GAS RESOURCE DURING THE RAP?**

A: No. Tri-State assessed each of its four existing natural gas generating facilities and its Burlington oil-fired generation resource for the potential for expansion of capacity from these existing generators. The following describes the results of that assessment:

- J.M. Shafer and Knutson: These units are located in an ozone nonattainment area. Turbine upgrades would be difficult due to environmental permit limitations and expensive due to the capital expenditures associated with the locations. These challenges are further described in Mr. Berger's Direct Testimony.
- Pyramid: Without firm gas transport for the facility, Tri-State must purchase delivered gas, which is likely to make capacity expansion at this facility less financially viable. Additionally, the location of Pyramid relative to the majority of Tri-State load would make this option significantly less than optimal.

- Limon and Burlington: Rather than facility expansion, Tri-State will seek to utilize existing surplus interconnect for renewable generation to be co-located at these sites. The process and benefits for utilization of surplus interconnection are described in the Direct Testimony of Ms. Hunter and Mr. Hubbard.

**Q: PLEASE OUTLINE THE HIGH-LEVEL STEPS THAT WILL ENABLE THIS UNIT TO COME ONLINE.**

A: Following the Phase I plan approval and selection of an Engineering, Procurement, and Construction ("EPC") contractor for the natural gas facility through the Phase II procurement processes, Tri-State anticipates filing an Application seeking a Certificate of Public Convenience and Necessity ("CPCN") from the Commission if the resource is sited in Colorado. If the resource were sited in Wyoming, Tri-State would instead seek a permit from the Wyoming Industrial Siting Council. Site selection, obtaining land rights, and environmental permitting processes for both the NGCC unit and CCS emission controls would be supported by the EPC contractor, and the transmission interconnection process would be discussed by Mr. Hubbard in that future filing.

**Q: WHAT STEPS IS TRI-STATE TAKING TO INFORM THE PHASE II PROCESS RELATED TO GAS RESOURCE SELECTION?**

A: Tri-State has engaged a third-party consulting firm to perform a siting study to analyze factors related to siting this new gas resource, including land availability, assessing gas pipeline accessibility, transmission interconnection availability, water availability, and carbon sequestration viability.

**Q: HOW WILL SELECTION OF AN EPC CONTRACTOR BE DETERMINED?**

A: Tri-State intends to issue a Dispatchable Resources RFP as part of its 2023 ERP Phase II process to obtain competitive bids for the gas resource and associated EPC contractor costs and requirements. Ms. Hunter's Direct Testimony further discusses this process in more detail.

**Q: DOES TRI-STATE INTEND TO BE THE GAS FACILITY OPERATOR OR OBTAIN AN OPERATIONS AND MAINTENANCE CONTRACTOR?**

A: Tri-State has not firmly determined all facets of the proposed gas unit's operations given the current stage of the modeling and planning process but anticipates that Tri-State would be the facility operator.

**Q: DOES TRI-STATE INTEND TO USE A PROJECT LABOR AGREEMENT FOR CONSTRUCTION OF THE FACILITY?[8]**

A: Tri-State's mission is to provide our Member systems a reliable, affordable, and responsible supply of electricity in accordance with cooperative principles. Tri-State is committed to competitively bidding all major contracts to ensure affordability goals are met. As such, Tri-State has not made a determination whether or not a labor agreement will be utilized for the construction of the new gas facility. However, if the new gas facility is located in the original Colorado Ute territory, then the on-site Tri-State Operations and Maintenance craft labor would be subject to Tri-State's collective bargaining agreement with the IBEW Local 111.

**Q: HOW WILL THE 2031 IMPLEMENTATION OF CCS BENEFIT THE NATURAL**

[8] Rule 3605(g)(II)(b) requires that the utility "…specify whether it agrees to use a project labor agreement for the construction or expansion of a generation facility."

**GAS PLANT INVESTMENT FOR TRI-STATE MEMBERS?**

A: Tri-State's modeling, based on industry research and vendor data, forecasts achieving up to a 97 percent carbon capture rate which results in a transformative reduction in the plant's carbon dioxide emissions from 765 lbs per net MWh (pre-CCS) to a possible low of 23 lbs per net MWh (post-CCS).[9] Additionally, with this carbon reduction, the facility's useful life can reasonably be extended beyond 20 years to 30 years.

**Q: WHAT IS THE LIFE OF A COMBINED CYCLE GAS RESOURCE?**

A: From a technical perspective, a newly constructed, highly efficient NGCC with CCS unit can be expected to operate for 30 years. From a modeling perspective, as identified in **Attachment B** ~~of the ERP Report (**Attachment LKT-1**),~~ LKT-7 the assumed life of the combined cycle gas resource with CCS is 30 years. In Tri-State's 2020 ERP Phase II, the book life of gas resources was limited to 20 years pursuant to the 2020 ERP Phase I Settlement Agreement.[10] However, the gas resource selected in the IRA Scenario includes application of CCS which extends the life of the resource back to normal operational expectations, while meeting existing emission targets and in anticipation of potential future environmental regulations. A 30-year operating lifetime assumption is consistent with Tri-State's expectations for actual unit depreciation and amortization.

**Q: DOES THE 2027 ERP PROVIDE AN OPPORTUNITY TO ASSESS THE**

[9] Federal PTC eligibility requires a carbon capture rate of at least 75 percent. Tri-State intends to evaluate Phase II gas bids that have a carbon capture rate between 75-97 percent.
[10] Section 3.6.8.

**CONTINUED VIABILITY OF THE 2031 CCS CONVERSION PATH FOR MANAGING CARBON FOR THE GAS PLANT?**

A: At the time of the 2027 ERP Phase I filing anticipated on June 1, 2027, Tri-State will provide the Commission and stakeholders with an update on CCS conversion progress.

**Q: DOES THIS CONCLUDE YOUR TESTIMONY?**

A: Yes.

**BEFORE THE PUBLIC UTILITIES COMMISSION**
**OF THE STATE OF COLORADO**

**PROCEEDING NO. 23A-____E**

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**APPLICATION OF TRI-STATE GENERATION AND TRANSMISSION ASSOCIATION, INC. FOR APPROVAL OF ITS 2023 ELECTRIC RESOURCE PLAN**

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**VERIFICATION**

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STATE OF CO LORADO )
) ss:
COUNTY OF ADAMS )

I, Barry W. Ingold, being duly sworn, do hereby depose and state that I have read the foregoing Direct Testimony, and the facts set forth therein are true and correct to the best of my knowledge, information, and belief.

Subscribed and sworn to before me this 15th day of November 2023, at Westminster, Colorado.

FAITH WARNER
NOTARY PUBLIC
STATE OF COLORADO
NOTARY ID 20184035614
MY COMMISSION EXPIRES 09/07/2026

TRI-STATE GENERATION AND TRANSMISSION ASSOCIATION, INC.

By: Barry W. Ingold
Barry W. Ingold
Chief Operating Officer

Witness my hand and official seal.

Faith Warner
Notary Public

My Commission expires: 9/7/2026.

BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

| | |
|---|---|
| Federal Power Act Section 202(c) | ) |
| Emergency Order: Tri-State | ) |
| Generation and Transmission | ) |
| Association, Platte River Power | ) |
| Authority, Salt River Project, | ) |
| PacifiCorp, and Xcel Energy | ) |

Exhibit to
Motion to Intervene and Request for Rehearing and Stay of
Public Interest Organizations

Exhibit 2-51:
Tri-State 2020 ERP



TRI-STATE
Generation and Transmission Association, Inc.

A Touchstone Energy® Cooperative



Colorado PUC E-Filings System

# 2020 Integrated Resource Plan/Electric Resource Plan

## Volume I

## December 1, 2020

**Submitted to:**

**Western Area Power Administration**
**Colorado Public Utilities Commission**

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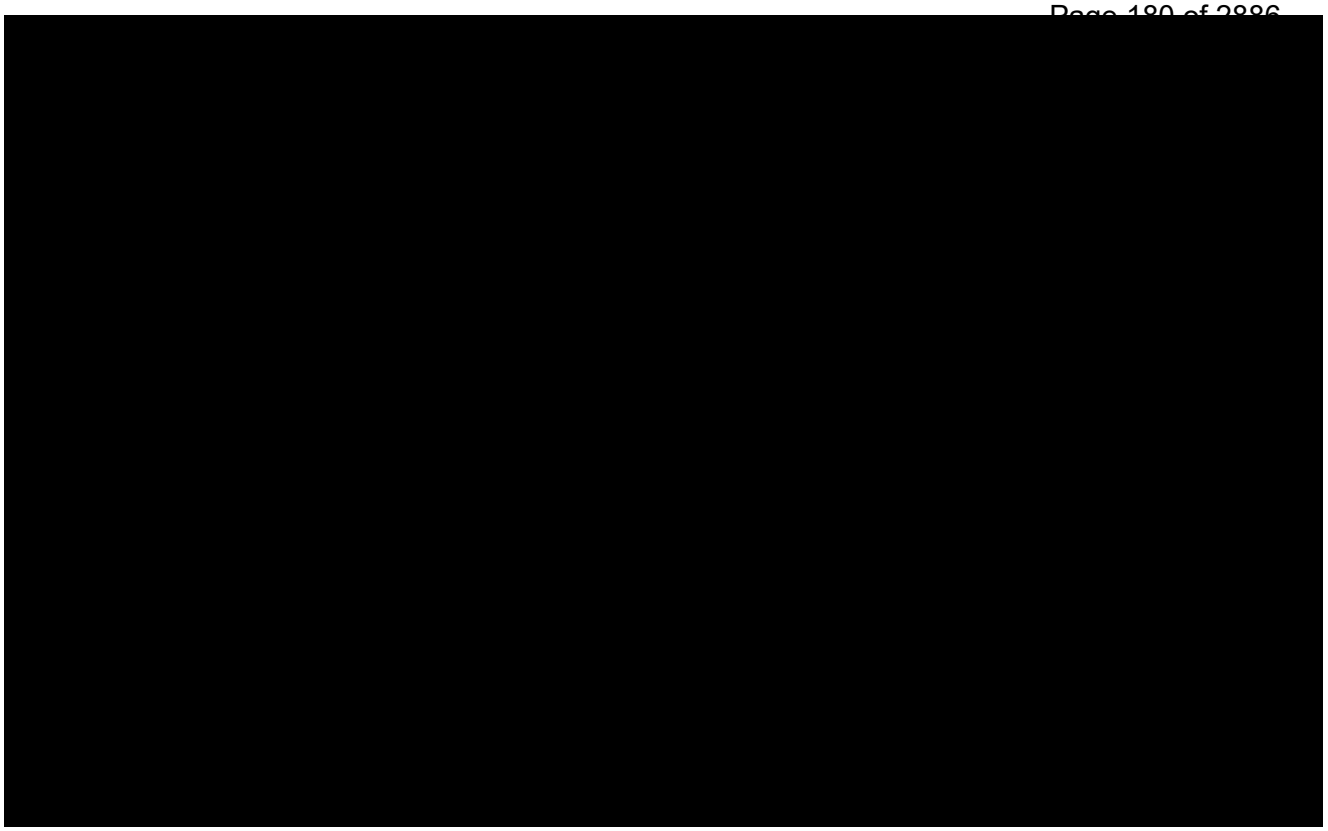

*Figure 11: Coal Forward Curve for UIPlanner (Nominal dollars)*

# 3 Assessment of Resources

## Overview of Thermal Resources

The following is a description of Tri-State-owned and leased resources in terms of unit characteristics, emission rates and revenue requirements. The assessment excludes the following items, as Tri-State does not have any applicable resources in these categories:

- Thermal resources under contract (3605(c)(I)(A))
- Utility-owned energy storage resources (3605(c)(I)(A))
- Utility-owned thermal resources that are not in service at this time (3605(c)(I)(D))

The following assumptions and interpretations apply:

- The Springerville 3 minimum operating level was lowered from 251 MW to 109 MW in the fall of 2019 as a result of modifications to the coal mills and related logic. The modifications allow pulverizers to operate in a 4-burner operation per pulverizer vs the normal 6-burner operation. This allows velocity to be maintained through the mills at lower fuel throughput.
- NOx limits for Craig 1 are in place to comply with the Colorado State Implementation Plan related to the Regional Haze rule.
- Capacity credits values were updated. See Section 5 Phase I Modeling Details “Table 56: Capacity Credit Values”.

- Tri-State has transitioned to the use of random hourly profiles for renewable resources instead of average hourly profiles.
- Escalante is excluded, as it was retired November 2020.
- Craig units 1, 2, and 3 useful life dates are identified as their respective announced retirement date.
- Net Dependable Capacity for coal resources is the same MW value as Maximum Capacity. (3605(c)(I)(B))
- Net Dependable Capacity for gas resources varies by season and is identified by Summer and Winter Capacity MW values. Gas resources reach their maximum capacity level in the winter. (3605(c)(I)(B))
- Marginal heat rate is calculated as the average heat rate over the RAP, which is identified as 2021 to 2030, for a typical dispatch.
- Fuel cost can be derived from provided heat rates for each resource and forward fuel curves for each fuel type. Tri-State does not utilize a forward fuel curve for oil, as its oil units are used for reliability events rather than economic dispatch and planning.
- Emissions rates are based on 2018 actuals data as provided by Tri-State Environmental.
- For Revenue Requirements where Tri-State has partial ownership in a resource, costs represent Tri-State's prorata share.
- There are no planned significant new investment or maintenance expenses. O&M and Capex costs are representative of necessary maintenance and improvements to maintain reliability of the resources. (3605(c)(I)(E))
- Annual capital expenses[3] are an average of annual expenses over the RPP of 2021 to 2040 for the life of each resource as determined by useful life or planned retirement date.
- Operating and Maintenance costs (fixed and variable) are held constant over the planning period in planning and dispatch models (2020 dollars). UIPlanner (financial model) escalates costs for inflation.
- Costs associated with the use of emissions control systems are not separately forecast, but are instead included in overall operating and maintenance costs.
- Although not a unit level revenue requirement, SCoC is included in the revenue requirement tables for thermal resources as Tri-State is aware of the requirement to consider this value in its assessment of resources and resulting dispatches in relation to the ERP process. The SCoC is calculated as the resource $CO_2$ emission rate of each unit in tons per MWh times $46.60/ton SCoC for 2021. SCoC annual costs and calculated cost by resource can be found in Section 5 Phase I Modeling Details under the Social Cost of Carbon subsection of this report.

[3] Tri-State's Generation Engineering Department works with generating station engineering personnel as well as station management and corporate finance, to develop and recommend the annual capital budget request for generation. The engineering staff also develops a list of future capital expenditures needed to maintain availability and reliability of the generation stations along with maintaining regulatory and environmental compliance. These future capital expenditures make up the long-term capital forecast for Tri-State resources.

- Tri-State's gas fleet consists of intermediate and peaking units, which are designed for cycling; therefore, no cycling or integration costs are identified for those resources. (3605(c)(I)(J))
- Forecast values for model inputs are based on a combination of historical data and known or upcoming changes that will impact model input values.

**Data Updates since August 3, 2030 Revision:**

- Tri-States entitlement of LRS was re-rated at 461MW.
- Rifle minimum operating level was updated to 65MW.
- Craig 1, Craig 2, and Craig 3 VOMs were updated to $1.93, $1.78, & $2.45 respectively.
- Scheduled Outages for 2021 to 2030 updated from filing.
- Tri-State is using May 2020 versus March 2020 gas and power forwards curves
- Updated SCoC costs based on Commission Staff feedback

**Coal-Fueled Generation Resources:**

Craig Generating Station: Craig Station is a three-unit, 1,285 MW coal-fired electric generating facility located near Craig, Colorado. Tri-State owns a 24% interest in Craig Units 1 and 2 (Yampa Project)[4], which have nameplate ratings of 427 MW and 410 MW, respectively; a 100% interest in Craig Unit 3, which has a capacity of 448 MW; and a 49% interest in the common facilities, which serve all three units. Tri-State is the operating agent for all three units and is responsible for the daily management, administration and maintenance of the facility. The non-fuel costs associated with operating Craig units 1 and 2 are divided on a pro-rata basis among all the participants[5]. Tri-State's total share of Craig Station is 648 MW. In 2016, Tri-State announced an agreement with regulators and environmental groups to retire Craig Unit 1 by December 31, 2025 as part of revisions to the Colorado regional haze State Implementation Plan. Tri-State has also announced that Craig Units 2 and 3 will be retired by 2030.

Laramie River Generating Station: The Laramie River Station (LRS) is a three-unit, 1,700 MW coal-fired electric generating facility located near Wheatland, Wyoming. As a participant in the Missouri Basin Power Project[6], Tri-State has a 27.1% interest (461 MW) in LRS. For operational purposes, Tri-State receives energy only from LRS 2 and 3 due to their location in the Western Interconnection. LRS 1 is scheduled solely to the Eastern Interconnection, and Tri-State does not receive energy from this resource. LRS is operated by BEPC.

Springerville Unit 3: Springerville Unit 3 is a 417 MW coal-fired electric generating unit that is part of the four-unit generation station located near Springerville, Arizona. One hundred percent of Unit 3 is leased by Tri-State. Tucson Electric Power (TEP) is the plant operator for the Springerville Generating Station.

[4] Yampa Project includes Craig 1 and Craig 2 and related common facilities.
[5] Yampa Project participants include Tri-State, Platte River Power Authority, PacifiCorp, Salt River Project and Public Service Company of Colorado.
[6] The Missouri Basin Power Project is the Laramie River Electric Generating Station and Transmission System located in Wyoming. Its participants include Tri-State, BEPC, the Western Minnesota Municipal Power Agency (Missouri River Energy Services), the Lincoln Electric System, and the Wyoming Municipal Power Agency (WMPA).

*Table 12: Unit Characteristics for Coal Resources*

| | **Average Heat Rate** *(btu/kWh)* | **Marginal Heat Rate** *(btu/kWh)* | **Quick Start Capable** *(Yes/No)* | **Minimum Operating Level** *(MW)* | **Useful Life**[7] |
|---|---|---|---|---|---|
| **Craig 1** | 10,316 | 10,518 | No | 31 | 12/31/2025[8] |
| **Craig 2** | 10,219 | 10,273 | No | 31 | 9/30/2028[9] |
| **Craig 3** | 10,135 | 10,256 | No | 130 | 12/31/2029[10] |
| **LRS 2** | 9,926 | 9,877 | No | 94 | 12/31/2041 |
| **LRS 3** | 10,286 | 10,205 | No | 94 | 12/31/2042 |
| **SPV3** | 9,945 | 10,174 | No | 109 | 12/31/2066 |

*Table 13: Emission Rates and Water Usage for Coal Resources*

| | **$CO_2$** *(lb/MWh)* | **$SO_2$** *(lb/MWh)* | **NOx** *(lb/MWh)* | **PM** *(lb/MWh)* | **HG** *(lb/MWh)* | **Water Usage** *(gal/MWh)* |
|---|---|---|---|---|---|---|
| **Craig 1** | 2319 | 0.378 | 2.771 | 0.042 | 0.00001700 | 492 |
| **Craig 2** | 2350 | 0.345 | 0.672 | 0.047 | 0.00001400 | 492 |
| **Craig 3** | 2090 | 1.308 | 2.248 | 0.061 | 0.00007800 | 492 |
| **LRS 2** | 2203 | 1.101 | 2.331 | 0.095 | 0.00004110 | 528 |
| **LRS 3** | 2407 | 1.823 | 2.410 | 0.177 | 0.00004680 | 528 |
| **SPV3** | 2139 | 0.838 | 0.787 | 0.031 | 0.00001600 | 546 |

*CO2, SO2, and NOx are lbs. per net MWh; PM and HG are lbs. per Gross MWh*

*Table 14: Revenue Requirements for Coal Resources (Real $)*

| | **Fixed O&M**[11] **Annual** *($000s)* | **Variable O&M** *($/MWh)* | **CapEx Costs Annual** *($000s)* | **Social Cost of Carbon** *($/MWh)* | **Integration & Cycling Costs** *($/MWh)* | **Fuel Curve** |
|---|---|---|---|---|---|---|
| **Craig 1** | [redacted] | | ~$800 | $54.03 | $0.129 | CRG (Inc) |
| **Craig 2** | | | ~$500 | $54.76 | $0.131 | CRG (Inc) |
| **Craig 3** | | | ~$3,000 | $48.70 | $0.124 | CRG (Inc) |
| **LRS 2** | | | ~$1,500 | $51.33 | $0.111 | LRSG |
| **LRS 3** | | | ~$1,500 | $56.08 | $0.108 | LRSG |
| **SPV3** | | | ~$6,500 | $48.94 | $0.138 | SPV3 |

[7] Useful Life is determined by Tri-State's 2017 Generation Depreciation study unless otherwise identified.
[8] This date is the announced retirement date per the YAMPA participants
[9] This date is the announced retirement date per the YAMPA participants
[10] This date has been modified from 12/31/2044 per Tri-State's 2017 Generation Depreciation Study and reflects Tri-State's announcement to retire all of Craig station by 2030.
[11] Fixed O&M forecasts are arrived at on a resource specific basis by taking the VOM provided by TS generation engineering and multiply the value times recent historical annual generation and subtracting the production from total O&M expense for the same year. This value divided by total O&M of the historical year provides a percentage for fixed costs. The percentage is then applied to forecasted O&M to arrive at the fixed portion.

Tri-State forward coal prices change annually. Figure 10 in Section 2 Commodity Pricing of this report shows the Coal Forward Curve in real (2020) dollars as used in CE and PO for the ERP scenario modeling.

## Gas & Oil-Fueled Generation Resources:

JM Shafer Generating Station: JM Shafer is a 272 MW natural gas-fueled, combined-cycle power plant located north of Fort Lupton, Colorado. The facility is wholly-owned by Tri-State subsidiary, Thermo Cogeneration Partnership, L.P., and operated by Tri-State.

Rifle Generating Station: Rifle Station is an 81 MW, natural gas-fueled combined-cycle power plant located near Rifle, Colorado. The facility is wholly-owned and operated by Tri-State.

Limon Generating Station: Limon Station is a two-unit, 140 MW, natural gas and oil-fired simple cycle combustion turbine facility located near Limon, Colorado. It is wholly-owned and operated by Tri-State.

Knutson Generating Station: Knutson Station is a two-unit, 140 MW, natural gas and oil-fired simple cycle combustion turbine facility located near Brighton, Colorado. It is wholly-owned and operated by Tri-State.

Pyramid Generating Station: Pyramid Station is a four-unit, 160 MW, natural gas and oil-fired simple cycle combustion turbine facility located near Lordsburg, New Mexico. It is wholly-owned and operated by Tri-State.

Burlington Generating Station: Burlington Station is a two-unit, 110 MW, oil-fired simple cycle combustion turbine facility located in Burlington, Colorado. It is wholly-owned and operated by Tri-State.

*Table 15: Unit Characteristics for Gas Resources*

| | **Summer Capacity** *(MW)* | **Winter Capacity** *(MW)* | **Fuel Type** | **Average Heat Rate** *(btu/kWh)* | **Marginal Heat Rate** *(btu/kWh)* | **Quick Start Capable** *(Yes/No)* | **Minimum Operating Level** *(MW)* | **Useful Life**[12] |
|---|---|---|---|---|---|---|---|---|
| **JM Shafer** | 272 | 272 | NG | 9,322 | 9,254 | No | 41 | 12/31/2047 |
| **Rifle** | 72 | 84 | NG | 10,321 | 9,676 | No | 65 | 12/31/2028 |
| **Limon** | 67 | 74 | NG/FO | 11,449 | 11,900 | Yes | 40 | 12/31/2048 |
| **Knutson** | 67 | 74 | NG/FO | 11,449 | 11,900 | No | 40 | 12/31/2048 |
| **Pyramid** | 40 | 40 | NG/FO | 9,742 | 9,909 | Yes | 25 | 12/31/2049 |
| **Burlington** | 48 | 60 | FO | 14,000 | -[13] | Yes | 25 | 12/31/2037 |

NG = Natural Gas; FO = Fuel Oil

[12] Useful Life is determined by Tri-State's 2017 Generation Depreciation study.
[13] Burlington did not dispatch over the RAP.

*Table 16: Emission Rates and Water Usage for Gas Resources*

| | $CO_2$ *(lb/MWh)* | $SO_2$ *(lb/MWh)* | NOx *(lb/MWh)* | PM *(lb/MWh)* | HG *(lb/MWh)* | Water Usage *(gal/MWh)* |
|---|---|---|---|---|---|---|
| **JM Shafer** | 981 | 0.008 | 0.747 | 0.080 | n/a | 348 |
| **Rifle** | 1206 | 0.001 | 2.611 | 0.239 | n/a | 1273 |
| **Limon** | 1495 | 0.008 | 0.378 | 0.062 | n/a | 57 |
| **Knutson** | 1502 | 0.009 | 0.341 | 0.124 | n/a | 21 |
| **Pyramid** | 1240 | 0.012 | 1.223 | 0.070 | n/a | 120 |
| **Burlington** | 2149 | 0.194 | 12.383 | 0.158 | n/a | 8.82 |

*CO2, SO2, and NOx are lbs. per net MWh; PM is lbs. per Gross MWh*

*Table 17: Revenue Requirements for Gas Resources*

| | Fixed O&M Annual *($000s)* | Variable O&M *($/MWh)* | CapEx Costs Annual *($000s)* | Social Cost of Carbon *($/MWh)* | Fuel Curve |
|---|---|---|---|---|---|
| **JM Shafer** | [redacted] | | ~$1,500 | $22.86 | CIG |
| **Rifle** | | | ~$200 | $28.10 | CIG |
| **Limon** | | | ~$275 | $34.83 | CIG |
| **Knutson** | | | ~$400 | $35.00 | CIG |
| **Pyramid** | | | ~$300 | $28.90 | Waha |
| **Burlington** | | | ~$450 | $50.07 | N/A |

Tri-State forward gas prices change monthly. Figure 9 in Section 2 Commodity Pricing of this report shows the gas forward curve used in the ERP scenario modeling in real (2020) dollars. Additional transport costs apply.

## Depreciation, Capital Balance, Amortization and Impairment:

Table 18 shows resource depreciation as of 4th Quarter 2019. Table 19 shows the capital balance, amortization and impairment of early retirements as identified in the preferred plan. It is important to note that Tri-State does not have project financing. Tri-State finances its assets as a portfolio; therefore, debt is not tied to specific units. In addition, annual fixed O&M and capital expenses are the only avoidable costs upon early retirement of a resource.

*Table 18: Resource Depreciation as of 4th Quarter 2019*

| FACDESC | LAND_COST | FAS_COST | 106_COST | CURRENT CAPITAL INVESTMENTS | TOTAL COST EXCLUDING LAND | DEPR_RESERVE | DEPRECIATION RATE | ESTIMATED ANNUAL DEPRECIATION |
|---|---|---|---|---|---|---|---|---|
| [redacted] | | | | | | | | |

*Table 19: Capital Balance, Amortization and Impairment of Resources per Preferred Plan*[14]

| Facility Description | Additional Capital Expenditures 2020 to Retirement | Early Retirement Date | Impaired Amount at Retirement | Annual amortization Early Retirement Date to Original Accounting Date (includes amortization of | Decommissioning (Including dismantling, severance, community assistance) |
|---|---|---|---|---|---|
| [redacted] | | | | | |

[14] The retirement of LRS 3 and SPV3 as identified in the preferred plan are subject to further study. Any retirement of an LRS facility will be determined by the MBPP participants.

Tri-State proactively works to reduce and eliminate capital expenses related to early retirement of resources as can be seen by the historical capital expense for the Nucla facility. Nucla was set to retire by December 31, 2022 as part of an agreement in 2016, which resulted in revisions to the Colorado Visibility and Regional Haze State Implementation Plan. Tri-State retired Nucla even earlier, in September 2019. Table 20 below shows that Nucla capital expenses were reduced to zero beginning in 2017.

*Table 20: Nucla Historical Capital Expenses*

| | 2015 | 2016 | 2017 | 2018 | 2019 |
|---|---|---|---|---|---|
| **NUCLA** | $1,573,481 | $1,334,631 | $0 | - | $0 |

Tri-State eliminated capital expenses for Nucla in the years leading up to the early retirement of the facility.

## Projected Availability Factors:

For modeling purposes, availability factors are a result of modeled forced outage factors as well as planned outage hours. Tri-State assumes a 4% forced outage factor for all coal-fired generation. Historically, gas and oil resources are not assigned a forced outage factor due to their limited annual capacity factors. Tri-State updated its models to reflect recommended forced outage factors as provided by B&V in Attachment Vol II 5-4 B&V Report on Review of Existing Resources.

Any required Phase 1 modeling work will include forced outage factors by unit. These factors were developed using 5 years of historical data from MicroGADS (2015-2019). Table 21 shows the forced outage factors for each thermal unit for the 5-year historical period.

*Table 21: Historical MicroGADS Forced Outage Factors for Tri-State Thermal Units*

| Resource | 2015 | 2016 | 2017 | 2018 | 2019 |
|---|---|---|---|---|---|
| **Craig 1** | 4.85 | 1.59 | 2.11 | 5.53 | 1.21 |
| **Craig 2** | 2.31 | 1.19 | 7.03 | 0.27 | 2.18 |
| **Craig 3** | 6.71 | 6.42 | 5.35 | 45.24[15] | 3.39 |
| **LRS 2** | 6.80 | 0.27 | 1.81 | 3.14 | 2.20 |
| **LRS 3** | 11.03 | 1.96 | 1.10 | 0.01 | 0.51 |
| **SPV3** | 2.11 | 15.08 | 15.88 | 7.77 | 9.09 |
| **Burlington 1** | 0.01 | 0.29 | 2.14 | 2.46 | 0.70 |
| **Burlington 2** | 1.98 | 0.00 | 0.10 | 0.67 | 0.32 |
| **Knutson 1** | 0.18 | 1.45 | 0.07 | 0.33 | 0.89 |
| **Knutson 2** | 0.10 | 1.71 | 0.05 | 0.21 | 0.66 |
| **Limon 1** | 0.02 | 2.16 | 0.11 | 1.71 | 0.29 |
| **Limon 2** | 0.31 | 0.88 | 1.15 | 0.45 | 0.57 |
| **Pyramid 1** | 0.01 | 0.53 | 0.15 | 0.27 | 0.35 |

[15] The Craig 3 steam turbine generator experienced a failure in 2018 resulting in a significant forced outage for repair. Due to the low probability of this type of event, Tri-State only considered 4 years of historical data to determine the forced outage factor for this thermal unit.

| Resource | 2015 | 2016 | 2017 | 2018 | 2019 |
|---|---|---|---|---|---|
| **Pyramid 2** | 0.02 | 0.42 | 0.30 | 2.76 | 0.07 |
| **Pyramid 3** | 0.16 | 0.78 | 0.02 | 0.26 | 0.97 |
| **Pyramid 4** | 0.01 | 0.46 | 0.04 | 0.26 | 2.41 |
| **Rifle**[16] | 0.00 | 5.17 | 2.64 | 2.01 | 1.43 |
| **JM Shafer** | 3.59 | 1.46 | 1.61 | 5.04 | 13.13 |

Table 22 provides the forced outage factors that will be used for any Phase 1 modeling for each thermal unit.

*Table 22: Forced Outage Factors to be used in Phase 1 modeling*

| Unit | 5-yr average (%) |
|---|---|
| **Craig 1** | 3.06 |
| **Craig 2** | 2.60 |
| **Craig 3** | 5.47 |
| **LRS 2** | 2.84 |
| **LRS 3** | 2.92 |
| **SPV3** | 9.99 |
| **Burlington 1** | 1.12 |
| **Burlington 2** | 0.61 |
| **Knutson 1** | 0.58 |
| **Knutson 2** | 0.55 |
| **Limon 1** | 0.86 |
| **Limon 2** | 0.67 |
| **Pyramid 1** | 0.26 |
| **Pyramid 2** | 0.71 |
| **Pyramid 3** | 0.44 |
| **Pyramid 4** | 0.64 |
| **Rifle** | 2.25 |
| **JM Shafer** | 4.97 |

[16] For combined cycle plants (Rifle and JM Shafer), forced outage factors are reported for reach gas turbine and each steam turbine. The Plant-wide forced outage factor is determined as the average forced outage factor of all units comprising the entire plant.

*Table 23: Applicable Scheduled Outage Plan over the RAP*

| | Craig 1 | Craig 2 | Craig 3 | LRS 2 | LRS 3 | SPV3 |
|---|---|---|---|---|---|---|
| **Start Date** | [redacted] | | | | | |
| **Stop Date** | | | | | | |
| **Start Date** | | | | | | |
| **Stop Date** | | | | | | |
| **Start Date** | | | | | | |
| **Stop Date** | | | | | | |
| **Start Date** | | | | | | |
| **Stop Date** | | | | | | |

## Third Party Assessment:

In preparation for Tri-State's 2020 Resource Plan processes, Tri-State engaged B&V to assist Tri-State with this assessment of existing resources. The above data reflects the outcome of that assessment where applicable. Specific areas of recommended change were as follows:

*Table 24: Summary of Third-Party Recommendations*

| B&V Recommendation | Conclusion |
|---|---|
| Increase Burlington Heat Rate | Adjustment made to heat rate curve |
| Change Availability Factor of Combined Cycle resources to 90% | Capacity factors are relatively low on Combined Cycle resources and remain so in $CO_2$ reduced cases, so Tri-State did not make this change at this time |
| Change Availability Factor of Combustion Turbine dual fuel resources to 96% | Capacity factors are relatively low on Combustion Turbine dual fuel resources and remain so in $CO_2$ reduced cases, so Tri-State did not make this change at this time |
| Change Availability Factor of Combustion Turbine oil resources to 98% | Capacity factors are relatively low on Combustion Turbine oil resources and remain so in $CO_2$ reduced cases, so Tri-State did not make this change at this time |
| Reduction in Rifle Fixed Costs | Rifle fixed costs are based on historical data. Tri-State will continue to monitor Rifle fixed costs and adjust as necessary. |
| Reduction to Burlington and Rifle NOx emission rate | Burlington and Rifle NOx emissions are based on historical data. There are conditions specific to these units that make their emissions rates higher than industry averages, so this will remain at the higher level for modeling purposes so as not to under represent potential emissions. |
| Increase to Rifle and JM Shafer $SO_2$ emission rates | Rifle and JM Shafer $SO_2$ emission rates are based on historical data. Tri-State will continue to monitor $SO_2$ for these units and update as needed. |
| Decrease of availability factor and related increase in equivalent forced outage factor for all gas units | JM Shafer and Rifle were modeled with the recommended 3% forced outage factor. Because capacity factors are relatively low on the remaining Combustion Turbine oil and |

| B&V Recommendation | Conclusion |
|---|---|
| | natural gas resources and remain so in $CO_2$ reduced cases, they were modeled at their winter and summer capacities. |

The B&V evaluation of resources detail can be found in Attachment Vol II 5-4 B&V Report on Review of Existing Resources.

## Resource Reference Data:

*Table 25: Resource Characteristics Reference*

| Tri-State Resource Table | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|
| State | Fuel | Name | Type | Unit Net Capacity (MW) | Modeled Capacity (MW) | Net Dependable Capacity (MW) | Year in Service/Contract Start | Estimated Retirement/End Date | Heat Rate | Availability Factor %* |
| -- | Basin | East Basin_East Basin | Unspecified | 317 | 317 | 317 | Effective 1/16/1975 | 2050 | N/A | N/A |
| -- | Basin | West Basin_West Basin | Unspecified | 268 | 268 | 268 | Effective 1/16/1975 | 2050 | N/A | N/A |
| AZ | Coal | Springerville 3 | Steam Turbine | 417 | 317 | 317 | 2006 | 2066 | 9,945 | 84.11 |
| CO | Coal | Craig 1 | Steam Turbine | 427 | 102 | 102 | 1980 | 2025 | 10,316 | 91.93 |
| CO | Coal | Craig 2 | Steam Turbine | 410 | 98 | 98 | 1979 | 2028 | 10,219 | 91.11 |
| CO | Coal | Craig 3 | Steam Turbine | 448 | 448 | 448 | 1984 | 2029 | 10,135 | 82.34 |
| WY | Coal | LRS 2 | Steam Turbine | 570 | 231 | 231 | 1981 | 2041 | 9,926 | 93.02 |
| WY | Coal | LRS 3 | Steam Turbine | 570 | 230 | 230 | 1982 | 2042 | 10,286 | 93.57 |
| CO | Oil | Burlington 1 | Frame CT | 55 | 55 | 48 | 1977 | 2037 | 14,000 | 97.92 |
| CO | Oil | Burlington 2 | Frame CT | 55 | 55 | 48 | 1977 | 2037 | 14,000 | 98.73 |
| CO | Gas/Oil | Knutson 1 | Frame CT | 70 | 70 | 67 | 2002 | 2048 | 11,449 | 96.78 |
| CO | Gas/Oil | Knutson 2 | Frame CT | 70 | 70 | 67 | 2002 | 2048 | 11,449 | 95.99 |
| CO | Gas/Oil | Limon 1 | Frame CT | 70 | 70 | 67 | 2003 | 2048 | 11,449 | 96.66 |
| CO | Gas/Oil | Limon 2 | Frame CT | 70 | 70 | 67 | 2003 | 2048 | 11,449 | 92.96 |
| CO | Gas | Rifle | Combined Cycle | 81 | 81 | 72 | 1987 | 2028 | 10,321 | 90.77 |
| CO | Gas | Shafer | Combined Cycle | 272 | 272 | 272 | 1994 | 2047 | 9,322 | 88.06 |
| NM | Gas/Oil | Pyramid 1 | Aeroderivative CT | 40 | 40 | 40 | 2003 | 2049 | 9,742 | 98.58 |
| NM | Gas/Oil | Pyramid 2 | Aeroderivative CT | 40 | 40 | 40 | 2003 | 2049 | 9,742 | 98.62 |
| NM | Gas/Oil | Pyramid 3 | Aeroderivative CT | 40 | 40 | 40 | 2003 | 2049 | 9,742 | 98.62 |
| NM | Gas/Oil | Pyramid 4 | Aeroderivative CT | 40 | 40 | 40 | 2003 | 2049 | 9,742 | 98.53 |
| -- | Hydro | WAPA CRSP | Hydro | 231 | 231 | 231 | Effective 10/1/1989 | 2057 | N/A | N/A |
| -- | Hydro | WAPA LAP | Hydro | 353 | 353 | 353 | Effective 10/1/1989 | 2054 | N/A | N/A |
| CO | Hydro | Small PPAs | Hydro PPA | 22 | 22 | 22 | various | various | N/A | N/A |
| CO | Solar | Axial | Tracking Array | 145 | 145 | 51 | 2023 | 2038 | N/A | N/A |
| CO | Solar | Coyote Gulch | Tracking Array | 120 | 120 | 42 | 2023 | 2038 | N/A | N/A |
| CO | Solar | Dolores | Tracking Array | 110 | 110 | 39 | 2023 | 2038 | N/A | N/A |
| CO | Solar | San Isabel | Tracking Array | 30 | 30 | 11 | 2016 | 2041 | N/A | N/A |
| CO | Solar | Spanish Peaks | Tracking Array | 100 | 100 | 35 | 2023 | 2038 | N/A | N/A |
| NM | Solar | Alta Luna | Tracking Array | 25 | 25 | 9 | 2017 | 2042 | N/A | N/A |
| NM | Solar | First Solar | Fixed | 30 | 30 | 11 | 2010 | 2035 | N/A | N/A |
| NM | Solar | SpanishPeaksTwo | Tracking Array | 40 | 40 | 14 | 2023 | 2038 | N/A | N/A |
| NM | Solar | TPE/Escalante | Tracking Array | 200 | 200 | 70 | 2023 | 2040 | N/A | N/A |
| CO | Wind | Carousel | Wind | 150 | 150 | 45 | 2015 | 2041 | N/A | N/A |
| CO | Wind | Colo Highlands | Wind | 91 | 91 | 27 | 2012 | 2032 | N/A | N/A |
| CO | Wind | Crossing Trails | Wind | 104 | 104 | 31 | 2020 | 2035 | N/A | N/A |
| CO | Wind | Kit Carson | Wind | 51 | 51 | 16 | 2010 | 2030 | N/A | N/A |
| CO | Wind | Niyol | Wind | 200 | 200 | 60 | 2021 | 2041 | N/A | N/A |
| CO | Wind | Twin Buttes | Wind | 76 | 76 | 23 | 2017 | 2042 | N/A | N/A |

* Based on historical data 2015 -2019

## Resource Historical Data:

Historical data for key modeling inputs are located in this subsection. Forecasts of modeling inputs are based on a combination of historical data and known present or upcoming changes that might impact forecasts. Explanations of deviations in historical data are included in this section.

Table 26 shows actual O&M expenses from 2015 to 2019 by resource or facility as available. Source of the data is Tri-State financials.

*Table 26: Annual Historical O&M by Resource ($000s)*[17]

| Resource | 2015 | 2016 | 2017 | 2018 | 2019 |
|---|---|---|---|---|---|
| [redacted] | | | | | |

*Table 27 Annual Historical Capital Expenses by Resource ($)*

| Resource | 2015 | 2016 | 2017 | 2018 | 2019 |
|---|---|---|---|---|---|
| **Craig 1&2** | $15,292,219 | $18,831,363 | $14,207,660 | $954,865 | $733,093 |
| **Craig 3** | $23,259,837 | $13,183,323 | $4,452,621 | $1,031,365 | $1,309,988 |
| **Burlington 1&2** | $280,336 | $17,504 | $16,817 | $479,627 | $210,512 |
| **Limon 1&2** | $66,250 | $422,075 | $746,182 | $1,877,331 | $387,852 |
| **Knutson 1&2** | $23,427 | $186,834 | $331,991 | $1,614,627 | $164,062 |
| **Pyramid 1,2,3,&4** | $397,258 | $287,402 | $11,604 | $798,934 | $133,503 |
| **Rifle** | $193,100 | $173,330 | $109,516 | $0 | $0 |
| **JM Shafer** | $26,070,218 | $5,556,312 | $1,810,132 | $18,514,466 | $10,295,315 |
| **LRS 2&3** | $9,128,577 | $7,341,987 | $24,835,767 | $28,798,723 | $14,340,410 |
| **SPV3** | $6,654,229 | $7,873,305 | $232,853 | $4,230,232 | $15,185,386 |
| **MISCELLANEOUS - OTHER** | $16,606,825 | $9,311,148 | $5,573,490 | $16,650,994 | $5,874,228 |
| **TOTAL GENERATION** | **$97,972,276** | **$63,184,583** | **$52,328,633** | **$74,951,164** | **$48,634,349** |

[17] Note that until June 30, 2019, a portion of JM Shafer was under a tolling contract to PSCO, and therefore history of resource operation and resulting costs is not necessarily reflective of future use.

Capital expenditures fluctuate to reflect ongoing needs that have been determined by site personnel, guidelines by equipment manufacturers and regulations for environmental, safety and regulatory compliance. The timing of larger capital upgrades is planned with major maintenance work when feasible. Table 28 explains larger capital expenditures by facility in recent history.

*Table 28: Explanation of Historical Capital Expenses*

| Facility | Explanation of Historical Capital Expenses |
|---|---|
| CRAIG 1&2 | Primary capex driver in 2015 and 2017 were environmental upgrades. Primary capex drivers in 2016 were environmental upgrades and controls upgrades. |
| CRAIG 3 | Primary capex drivers in 2015 were environmental upgrades, controls upgrades and water purchases. Primary capex driver in 2016 was the continuation of the environmental upgrades. |
| BURLINGTON 1&2 | Primary capex driver in 2018 was replacing various protective relaying. |
| LIMON 1&2 | Primary capex driver in 2018 upgrading/replacing the inlet silencers for both engines. |
| KNUTSON 1&2 | Primary capex driver in 2018 upgrading/replacing the inlet silencers for both engines. |
| PYRAMID 1,2,3&4 | Primary capex driver in 2018 replacing various protective relaying. |
| RIFLE | Tri-State has been actively trying to decrease capital expenses at Rifle other than what is necessary for compliance. |
| JM SHAFER | Primary capex drivers for 2015 and 2018 were water purchases and water infrastructure for operations. Primary capex drivers for 2019 were large maintenance projects including a complete engine overhaul/rebuild. |
| LRS 2&3 | Primary capex drivers in 2017 and 2018 were environmental compliance projects. (Selective Catalytic Reduction and Selective Noncatalytic Reduction). |
| SPV3 | Primary capex driver in 2019 was the superheater reheater pendant replacement. |

*Table 29: Annual Historical Fuel Price by Pipeline ($/MMBtu)*

| Hub | 2015 | 2016 | 2017 | 2018 | 2019 |
|---|---|---|---|---|---|
| **CIG** | $2.39 | $2.25 | $2.63 | $2.58 | $2.06 |
| **WAHA** | $2.46 | $2.33 | $2.68 | $2.01 | $0.86 |

The average of the last 5 years (2015-2019) of CIG prices is $2.38/MMBtu while WAHA's 5 year average is $2.07/MMBtu. In Section 2 - Commodity Pricing - Gas Forward Curve Tri-State describes the methodology for developing its forward gas curves. The 1st five years (2021 – 2025) of forward curve pricing show CIG's average to be $2.20/MMBtu and WAHA is at $2.07/MMBtu. Following those years, the forecast shows gas prices increasing based upon blended midterm and fundamental pricing.

*Table 30: Historical Coal Fuel Pricing by Resource ($/MMBtu)*

| Coal Source | 2016 | 2017 | 2018 | 2019 |
|---|---|---|---|---|
| CRG | [redacted] | | | |
| LRS | | | | |
| SPV3 | | | | |

*Table 31 Annual Historical Heat Rate (btu/kWh)*

| Resource | 2015 | 2016 | 2017 | 2018 | 2019 |
|---|---|---|---|---|---|
| Craig 1&2 | 10153 | 10196 | 10165 | 10232 | 9370 |
| Craig 3 | 10157 | 10219 | 10121 | 10472 | 9526 |
| LRS 2 & 3 | 9345 | 9965 | 9080 | 9800 | 9082 |
| SPV3 | 10115 | 10404 | 10211 | 9236 | 10700 |
| Burlington 1&2 | * | * | * | * | 13444 |
| Knutson 1&2 | * | 12803 | 12761 | 9070 | 12399 |
| Limon 1&2 | 12860 | 12434 | 12525 | 12381 | 12048 |
| Pyramid 1,2,3,&4 | 10415 | 10319 | 10444 | 10421 | 8163 |
| Rifle | 10272 | 9677 | 10135 | * | 9663 |
| JM Shafer | 8820 | 8368 | 8642 | 7840 | 8930 |

*** insufficient data**

*Table 32: Annual Historical $CO_2$ Emissions Rate by Resource*

| Unit | $CO_2$ (lbs/net MWh) | | | | |
|---|---|---|---|---|---|
| | 2015 | 2016 | 2017 | 2018 | 2019 |
| LRS 2 | 2350 | 2265 | 2225 | 2203 | 2379 |
| LRS 3 | 2510 | 2530 | 2556 | 2407 | 2671 |
| Craig 1 | 2282 | 2244 | 2299 | 2319 | 2395 |
| Craig 2 | 2312 | 2252 | 2315 | 2350 | 2406 |
| Craig 3 | 2110 | 2076 | 2084 | 2090 | 2171 |
| Springerville 3 | 2250 | 2278 | 2160 | 2139 | 2392 |
| Burlington 1 | 2174 | 2444 | 2452 | 2212 | 2248 |
| Burlington 2 | 2145 | 2122 | 2261 | 2086 | 2259 |
| Pyramid 1 | 1271 | 1203 | 1167 | 1240 | 1179 |
| Pyramid 2 | 1196 | 1211 | 1252 | 1232 | 1203 |
| Pyramid 3 | 1215 | 1372 | 1289 | 1250 | 1187 |
| Pyramid 4 | 1275 | 1218 | 1237 | 1238 | 1206 |
| Rifle | 1197 | 1109 | 1195 | 1206 | 1154 |
| Limon 1 | 1560 | 1525 | 1453 | 1498 | 1480 |
| Limon 2 | 1528 | 1566 | 1546 | 1492 | 1479 |
| Knutson 1 | 1469 | 1489 | 1479 | 1504 | 1481 |
| Knutson 2 | 1507 | 1992 | 1533 | 1500 | 1517 |
| JM Shafer | 1050 | 986 | 981 | 981 | 944 |

*Table 33: Annual Historical $SO_2$ Emissions Rate by Resource*

| Unit | $SO_2$ (lbs/net MWh) | | | | |
|---|---|---|---|---|---|
| | 2015 | 2016 | 2017 | 2018 | 2019 |
| **LRS 2** | 1.209 | 0.819 | 1.073 | 1.101 | 1.164 |
| **LRS 3** | 1.972 | 1.545 | 1.598 | 1.823 | 1.525 |
| **Craig 1** | 0.525 | 0.470 | 0.489 | 0.378 | 0.511 |
| **Craig 2** | 0.555 | 0.497 | 0.501 | 0.345 | 0.460 |
| **Craig 3** | 1.266 | 1.384 | 1.251 | 1.308 | 1.248 |
| **Springerville 3** | 0.708 | 0.816 | 0.932 | 0.838 | 0.810 |
| **Burlington 1** | 0.000 | 0.000 | 0.222 | 0.206 | 0.113 |
| **Burlington 2** | 0.000 | 0.000 | 0.174 | 0.182 | 0.113 |
| **Pyramid 1** | 0.017 | 0.011 | 0.011 | 0.013 | 0.006 |
| **Pyramid 2** | 0.014 | 0.020 | 0.027 | 0.017 | 0.006 |
| **Pyramid 3** | 0.011 | 0.063 | 0.024 | 0.012 | 0.006 |
| **Pyramid 4** | 0.011 | 0.012 | 0.015 | 0.006 | 0.006 |
| **Rifle** | 0.000 | 0.000 | 0.000 | 0.001 | 0.000 |
| **Limon 1** | 0.011 | 0.008 | 0.009 | 0.008 | 0.010 |
| **Limon 2** | 0.008 | 0.008 | 0.008 | 0.008 | 0.008 |
| **Knutson 1** | 0.008 | 0.007 | 0.009 | 0.009 | 0.008 |
| **Knutson 2** | 0.008 | 0.011 | 0.009 | 0.010 | 0.008 |
| **JM Shafer** | 0.005 | 0.005 | 0.005 | 0.008 | 0.005 |

*Table 34: Annual Historical NOx Emissions Rate by Resource*

| Unit | NOx (lbs/net MWh) | | | | |
|---|---|---|---|---|---|
| | 2015 | 2016 | 2017 | 2018 | 2019 |
| **LRS 2** | 1.682 | 1.650 | 1.648 | 2.331 | 1.600 |
| **LRS 3** | 1.774 | 1.786 | 1.906 | 2.410 | 1.824 |
| **Craig 1** | 2.735 | 2.622 | 2.748 | 2.771 | 2.878 |
| **Craig 2** | 2.790 | 2.681 | 2.482 | 0.672 | 0.721 |
| **Craig 3** | 2.972 | 2.937 | 2.815 | 2.248 | 2.404 |
| **Springerville 3** | 0.827 | 0.817 | 0.900 | 0.787 | 0.963 |
| **Burlington 1** | 11.573 | 12.661 | 13.210 | 12.482 | 12.132 |
| **Burlington 2** | 11.657 | 11.502 | 12.123 | 12.283 | 12.193 |
| **Pyramid 1** | 1.358 | 1.087 | 1.208 | 1.253 | 1.189 |
| **Pyramid 2** | 1.306 | 1.190 | 1.122 | 1.169 | 1.218 |
| **Pyramid 3** | 1.176 | 1.287 | 1.299 | 1.253 | 1.178 |
| **Pyramid 4** | 1.607 | 1.186 | 1.127 | 1.218 | 1.157 |
| **Rifle** | 1.974 | 3.771 | 1.827 | 2.611 | 2.016 |
| **Limon 1** | 0.445 | 0.321 | 0.359 | 0.432 | 0.375 |
| **Limon 2** | 0.342 | 0.337 | 0.405 | 0.324 | 0.383 |
| **Knutson 1** | 0.368 | 0.349 | 0.363 | 0.345 | 0.341 |
| **Knutson 2** | 0.373 | 0.488 | 0.392 | 0.337 | 0.358 |
| **JM Shafer** | 0.773 | 0.735 | 0.749 | 0.747 | 0.703 |

*Table 35: Annual Historical Hg Emissions Rate by Resource*

| Unit | Hg (lbs/gross MWh) | | | | |
|---|---|---|---|---|---|
| | 2015 | 2016 | 2017 | 2018 | 2019 |
| **LRS 2** | 0.0000053 | 0.0000064 | 0.0000061 | 0.0000411 | 0.0000086 |
| **LRS 3** | 0.0000042 | 0.0000091 | 0.0000097 | 0.0000468 | 0.0000111 |
| **Craig 1** | 0.0000014 | 0.0000017 | 0.0000030 | 0.0000170 | 0.0000044 |
| **Craig 2** | 0.0000027 | 0.0000036 | 0.0000025 | 0.0000140 | 0.0000036 |
| **Craig 3** | 0.0000089 | 0.0000092 | 0.0000091 | 0.0000780 | 0.0000070 |
| **Springerville 3** | 0.0000038 | 0.0000024 | 0.0000053 | 0.0000160 | 0.0000045 |
| **Burlington 1** | N/A | N/A | N/A | N/A | N/A |
| **Burlington 2** | N/A | N/A | N/A | N/A | N/A |
| **Pyramid 1** | N/A | N/A | N/A | N/A | N/A |
| **Pyramid 2** | N/A | N/A | N/A | N/A | N/A |
| **Pyramid 3** | N/A | N/A | N/A | N/A | N/A |
| **Pyramid 4** | N/A | N/A | N/A | N/A | N/A |
| **Rifle** | N/A | N/A | N/A | N/A | N/A |
| **Limon 1** | N/A | N/A | N/A | N/A | N/A |
| **Limon 2** | N/A | N/A | N/A | N/A | N/A |
| **Knutson 1** | N/A | N/A | N/A | N/A | N/A |
| **Knutson 2** | N/A | N/A | N/A | N/A | N/A |
| **JM Shafer** | N/A | N/A | N/A | N/A | N/A |

*Table 36: Annual Historical PM Emissions Rate by Resource*

| Unit | PM (lbs/gross MWh) | | | | |
|---|---|---|---|---|---|
| | 2015 | 2016 | 2017 | 2018 | 2019 |
| **LRS 2** | 0.1410 | 0.0702 | 0.0544 | 0.0953 | 0.1052 |
| **LRS 3** | 0.1767 | 0.2115 | 0.0758 | 0.1770 | 0.1778 |
| **Craig 1** | 0.0845 | 0.0980 | 0.0649 | 0.0421 | 0.0379 |
| **Craig 2** | 0.0893 | 0.0552 | 0.0462 | 0.0469 | 0.0467 |
| **Craig 3** | 0.0522 | 0.0478 | 0.0399 | 0.0614 | 0.0124 |
| **Springerville 3** | 0.0378 | 0.0287 | 0.0748 | 0.0306 | 0.2478 |
| **Burlington 1** | 0.1601 | 0.1799 | 0.1803 | 0.1620 | 0.1654 |
| **Burlington 2** | 0.1580 | 0.1562 | 0.1653 | 0.1530 | 0.1663 |
| **Pyramid 1** | 0.0707 | 0.0661 | 0.0641 | 0.0710 | 0.0643 |
| **Pyramid 2** | 0.0666 | 0.0682 | 0.0709 | 0.0720 | 0.0658 |
| **Pyramid 3** | 0.0670 | 0.0835 | 0.0723 | 0.0720 | 0.0645 |
| **Pyramid 4** | 0.0699 | 0.0673 | 0.0686 | 0.0650 | 0.0660 |
| **Rifle** | 0.2829 | 0.1699 | 0.1881 | 0.2390 | 0.2370 |
| **Limon 1** | 0.0735 | 0.0598 | 0.0606 | 0.0616 | 0.0614 |
| **Limon 2** | 0.0604 | 0.0620 | 0.0618 | 0.0625 | 0.0593 |
| **Knutson 1** | 0.1170 | 0.1158 | 0.1142 | 0.1237 | 0.1156 |
| **Knutson 2** | 0.1221 | 0.1205 | 0.1186 | 0.1237 | 0.1174 |
| **J M Shafer** | 0.0570 | 0.0545 | 0.0551 | 0.0804 | 0.0514 |

*Table 37: Annual Historical Water Usage Rate by Resource*

| Unit | Water Usage (gal/MWh) | | | | |
|---|---|---|---|---|---|
| | 2015 | 2016 | 2017 | 2018 | 2019 |
| **LRS 2** | 543 | 541 | 509 | 528 | 492 |
| **LRS 3** | 514 | 507 | 543 | 528 | 475 |
| **Craig 1** | 488 | 496 | 494 | 492 | 498 |
| **Craig 2** | 488 | 496 | 494 | 492 | 498 |
| **Craig 3** | 488 | 496 | 494 | 492 | 498 |
| **Springerville 3** | 555 | 571 | 584 | 546 | 625 |
| **Burlington 1** | 16 | 12 | 4 | 8.82 | 1 |
| **Burlington 2** | 16 | 12 | 4 | 8.82 | 1 |
| **Pyramid 1** | 107 | 129 | 132 | 120 | 93 |
| **Pyramid 2** | 107 | 129 | 132 | 120 | 93 |
| **Pyramid 3** | 107 | 129 | 132 | 120 | 93 |
| **Pyramid 4** | 107 | 129 | 132 | 120 | 93 |
| **Rifle** | 1350 | 1372 | 1951 | 1273 | 495 |
| **Limon 1** | 31 | 17 | 59 | 57 | 47 |
| **Limon 2** | 31 | 17 | 59 | 57 | 47 |
| **Knutson 1** | 46 | 10 | 32 | 21 | 18 |
| **Knutson 2** | 46 | 10 | 32 | 21 | 18 |
| **J M Shafer** | 255 | 472 | 451 | 348 | 460 |

## Overview of Purchases

The following list provides summary information regarding current firm purchase power agreements in regards to capacity, energy and demand side resources. Tri-State does not have any wheeling or coordination agreements that provide capacity and energy.

Contract Purchases and Renewable PPAs differ from thermal resources in regards to applicable characteristics and costs. The format used below is intended to present the applicable data for these agreements as required in Rule 3605(c).

Summer capacities are representative of contract demand available to serve July peak.

Net Dependable Capacities (Capacity Credit) for renewable resources are identified in Section 5 Phase I Modeling Details under the Modeling Assumptions subsection of this report.

### Contract Purchases:

Basin CROD Western Interconnection BEPC: Colorado & Wyoming: 268 MW summer capacity, ~1580 GWh/year[18]. Effective Date 1/16/1975; Restructured Date 10/1/2017; Contract Expires 12/31/2050.

- If either party wishes to terminate this agreement on its expiration date of 12/31/2050, notice must be given to the other party by January 1, 2045 in writing. Otherwise, this contract will remain in effect beyond its expiration date of 12/31/2050 until such time that either party gives to the other party not less than five years written notice of intent to terminate.

[18] Profile detail is shown in the Contract Profile Information subsection.

Basin Electrically East BEPC: All Requirements Purchase Contract for Electrically East Loads[19], Effective Date 1/16/1975; Restructured Date 10/1/2017; Contract Expires 12/31/2050.

- If either party wishes to terminate this agreement on its expiration date of 12/31/2050, notice must be given to the other party by January 1, 2045 in writing. Otherwise, this contract will remain in effect beyond its expiration date of 12/31/2050 until such time that either party gives to the other party not less than five years written notice of intent to terminate.

CRSP WAPA: 231 MW summer capacity ~1424 GWh/year. Seasonal Contract Rate of Delivery, specified monthly capacity and energy, and multiple delivery points apply to this contract. Effective Date 10/1/1989; Renewed Date 10/1/2017; Contract Expires 9/30/2057.

- Contracts TS-89-0005 and PL-89-0002 expire end of day, 9/30/2024. Contract TS-17-0128 is currently effective and commences delivery of Firm Electric Service beginning of day, 10/1/2024 through end of day 9/30/2057.

LAP WAPA: 353 MW summer capacity, ~900 GWh/year. Seasonal Contract Rate of Delivery, specified monthly capacity and energy, and multiple delivery points apply to this contract, Effective Date 10/1/1989; Contract Expiration 9/30/2054.

- Contract TS-89-0002 expires end of day, 9/30/2024. Contract TS-14-0238 is currently effective and commences delivery of Firm Electric Service beginning of day, 10/01/2024 through end of day, 9/30/2054.
- LAP contract includes rights to Mt. Elbert pump back storage 176 MW summer capacity with a 68% efficiency and prescribed generating and pumping hours. The Mt. Elbert contract capacity shares transmission with the LAP contract and the combination of usage cannot exceed the LAP contract max capacity in any hour.

Native American WAPA Allocations: Monthly (fixed schedule peaking) at 5 MW annually, ~28 GWh/year. Effective Date 10/1/2004; Expires 10/1/2024.

Central Valley Electric: ~1 MW capacity, ~5 GWh/year. Effective Date 12/05/1996; Contract Expires Evergreen

Public Service Company of New Mexico Unit Contingent Purchase: 100MW unit contingent purchase from PNM at SJ345. 100 MW (Maximum Capacity) ~876 GWh/year. Effective Date 06/01/2017; Contract Expires 05/31/2022. This is the purchase side of a swap that reduces spinning reserve obligations.

Additionally, Tri-State has several contracts under WSPP agreements that serve Utility Member system load associated with wind and solar facility station service for generators that are under contract and deliver energy to third party utilities but are located in a Tri-State Utility Member's service territory. These contracts are de minimis in nature (i.e., under 1 GWh in annual energy; 2 MW maximum demand).

- PRPA – Rawhide Solar Station Service (SS): Contract commenced 9/1/2016; contract expires 9/1/2021 – Expected to renew making the new contract expiration 9/1/2026
- PRPA – Prairie Solar SS: Contract commenced 5/1/2020; contract expires 5/1/2025

[19] Profile detail is shown in the Contract Profile Information subsection.

- PRPA – Roundhouse Wind SS: Contract commenced 6/3/2020; contract expires 6/1/2025
- CSU – Palmer Solar SS: Contract commenced 4/1/2020; contract expires 4/1/2025

## Contract Profile Information:

*Projected Basin Contract Energy & Demand*

Basin CROD Western Interconnection contract energy profile is a set hourly profile identified by point of delivery. Stegall West 230KV Bus is located in Nebraska. AU 230KV and Story 230KV busses are located in Colorado. Figures 12 and 13 show the hourly profiles by point of delivery for each month:

POINT OF DELIVERY: STEGALL WEST 230KV BUS

| Month\HE | 1 | 2 | 3 | 4 | 5 | 6 | 7 | 8 | 9 | 10 | 11 | 12 | 13 | 14 | 15 | 16 | 17 | 18 | 19 | 20 | 21 | 22 | 23 | 24 | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| JAN | 73 | 71 | 72 | 71 | 74 | 75 | 84 | 92 | 91 | 88 | 86 | 85 | 82 | 81 | 79 | 80 | 86 | 94 | 97 | 95 | 94 | 90 | 85 | 75 | 2,000 |
| FEB | 73 | 72 | 72 | 72 | 74 | 81 | 85 | 91 | 90 | 89 | 88 | 86 | 83 | 82 | 81 | 81 | 85 | 89 | 97 | 96 | 94 | 91 | 85 | 74 | 2,011 |
| MAR | 69 | 67 | 68 | 68 | 72 | 76 | 83 | 82 | 82 | 81 | 80 | 77 | 75 | 75 | 74 | 74 | 75 | 79 | 84 | 84 | 84 | 80 | 74 | 69 | 1,832 |
| APR | 48 | 46 | 46 | 46 | 47 | 51 | 56 | 57 | 58 | 58 | 58 | 55 | 55 | 54 | 54 | 54 | 55 | 56 | 58 | 59 | 60 | 58 | 53 | 49 | 1,291 |
| MAY | 54 | 52 | 51 | 51 | 52 | 55 | 61 | 63 | 65 | 65 | 65 | 65 | 65 | 65 | 65 | 65 | 67 | 67 | 67 | 68 | 68 | 67 | 63 | 58 | 1,484 |
| JUN | 80 | 75 | 73 | 72 | 73 | 76 | 81 | 93 | 98 | 100 | 102 | 105 | 105 | 106 | 106 | 107 | 107 | 108 | 107 | 108 | 107 | 107 | 100 | 88 | 2,284 |
| JUL | 89 | 85 | 84 | 83 | 83 | 84 | 88 | 99 | 104 | 108 | 112 | 114 | 115 | 117 | 118 | 119 | 119 | 119 | 118 | 118 | 115 | 115 | 107 | 94 | 2,507 |
| AUG | 88 | 85 | 84 | 83 | 83 | 85 | 90 | 99 | 104 | 107 | 110 | 112 | 113 | 114 | 115 | 117 | 117 | 117 | 117 | 117 | 117 | 113 | 104 | 92 | 2,483 |
| SEP | 54 | 53 | 52 | 51 | 52 | 55 | 61 | 70 | 71 | 73 | 73 | 74 | 74 | 74 | 76 | 76 | 76 | 78 | 79 | 81 | 81 | 76 | 69 | 56 | 1,635 |
| OCT | 55 | 52 | 51 | 51 | 52 | 55 | 60 | 69 | 71 | 72 | 72 | 70 | 68 | 68 | 69 | 70 | 72 | 73 | 73 | 73 | 73 | 70 | 67 | 55 | 1,561 |
| NOV | 67 | 67 | 67 | 67 | 70 | 74 | 78 | 81 | 81 | 82 | 80 | 77 | 76 | 75 | 74 | 76 | 80 | 85 | 86 | 85 | 84 | 80 | 75 | 70 | 1,837 |
| DEC | 72 | 72 | 72 | 72 | 73 | 76 | 84 | 90 | 90 | 89 | 87 | 85 | 83 | 81 | 80 | 87 | 93 | 99 | 100 | 99 | 97 | 94 | 87 | 76 | 2,038 |

Amounts shown in MW, hours shown are Hour-Ending and in Mountain Standard Time

*Figure 12: Basin CROD Western Interconnection Stegall West 230KV Bus Hourly Profile*

POINT OF DELIVERY: AULT 230KV and STORY 230KV BUSSES

| Month\HE | 1 | 2 | 3 | 4 | 5 | 6 | 7 | 8 | 9 | 10 | 11 | 12 | 13 | 14 | 15 | 16 | 17 | 18 | 19 | 20 | 21 | 22 | 23 | 24 | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| JAN | 92 | 90 | 90 | 90 | 93 | 95 | 105 | 115 | 114 | 111 | 109 | 107 | 103 | 102 | 99 | 100 | 108 | 118 | 122 | 119 | 118 | 114 | 106 | 95 | 2,515 |
| FEB | 91 | 90 | 90 | 90 | 93 | 102 | 107 | 114 | 114 | 112 | 110 | 108 | 104 | 103 | 102 | 102 | 106 | 112 | 122 | 121 | 119 | 114 | 107 | 93 | 2,526 |
| MAR | 86 | 85 | 85 | 86 | 90 | 96 | 104 | 104 | 104 | 102 | 100 | 96 | 94 | 94 | 94 | 94 | 94 | 100 | 105 | 106 | 105 | 100 | 93 | 87 | 2,304 |
| APR | 60 | 58 | 57 | 57 | 59 | 64 | 70 | 72 | 72 | 72 | 72 | 70 | 69 | 68 | 67 | 67 | 69 | 71 | 72 | 73 | 75 | 73 | 66 | 61 | 1,614 |
| MAY | 67 | 65 | 64 | 64 | 65 | 70 | 76 | 80 | 81 | 82 | 82 | 82 | 82 | 82 | 82 | 82 | 85 | 85 | 85 | 85 | 85 | 84 | 80 | 72 | 1,867 |
| JUN | 100 | 95 | 92 | 92 | 92 | 96 | 102 | 118 | 123 | 126 | 130 | 131 | 132 | 133 | 133 | 135 | 136 | 136 | 136 | 136 | 136 | 134 | 126 | 110 | 2,880 |
| JUL | 111 | 107 | 106 | 104 | 104 | 106 | 110 | 123 | 130 | 135 | 140 | 143 | 145 | 146 | 148 | 149 | 149 | 149 | 148 | 148 | 145 | 144 | 135 | 117 | 3,142 |
| AUG | 110 | 107 | 106 | 104 | 105 | 107 | 111 | 124 | 129 | 135 | 137 | 140 | 142 | 143 | 145 | 146 | 146 | 146 | 146 | 146 | 146 | 146 | 140 | 130 | 115 | 3,106 |
| SEP | 68 | 66 | 64 | 64 | 65 | 69 | 76 | 88 | 90 | 91 | 92 | 93 | 93 | 93 | 95 | 95 | 96 | 98 | 98 | 102 | 102 | 95 | 85 | 70 | 2,048 |
| OCT | 68 | 65 | 64 | 64 | 65 | 69 | 76 | 86 | 89 | 90 | 90 | 88 | 85 | 85 | 86 | 88 | 90 | 92 | 92 | 92 | 91 | 88 | 84 | 69 | 1,956 |
| NOV | 84 | 83 | 83 | 83 | 87 | 93 | 98 | 102 | 102 | 102 | 100 | 97 | 95 | 93 | 93 | 96 | 99 | 106 | 108 | 106 | 104 | 100 | 94 | 87 | 2,295 |
| DEC | 90 | 90 | 89 | 89 | 91 | 96 | 105 | 113 | 113 | 111 | 108 | 106 | 103 | 102 | 100 | 108 | 117 | 123 | 125 | 124 | 122 | 118 | 109 | 95 | 2,547 |

Amounts shown in MW, hours shown are Hour-Ending and in Mountain Standard Time

*Figure 13: Basin CROD Western Interconnection AU 230KV and STORY 230KV Busses Hourly Profile*

Basin Electrically East contract has an energy and demand profile based on forecast Electrically East (Nebraska and Colorado) load, as this is a full requirements contract. The load served by this full requirements contract is located in the Eastern Interconnection primarily in the state of Nebraska with a small amount of Colorado load in the far northeastern portion of Colorado. On an average annual basis, ~15% of this purchase serves Colorado. The balance of this purchase serves load in Nebraska.

Hourly Profiles for the Basin Electrically East contract vary by season and are heavily impacted by irrigation. Figure 14 shows a typical hourly profile in a given day for the Irrigation and Non-Irrigation seasons. As shown by the orange line in the graph the hourly load during non-irrigation season barely exceeds 50 MW with a sharp morning peak, while the hourly load during irrigation season (yellow line) has a sustained daytime peak closer to ~280MW.

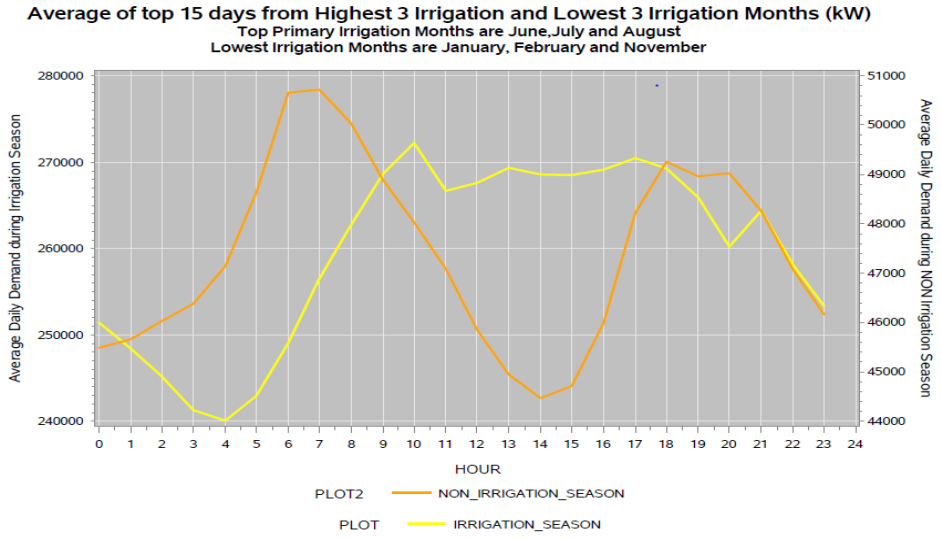


*Figure 14: Basin Electrically East Irrigation and Non-Irrigation Seasons Demand Profiles*

Below is a snapshot of historical energy and demand for the Basin Electrically East contract by month:

*Table 38: Historical Energy and Demand for Basin Electrically East*

| Year | Data/UOM | Jan | Feb | Mar | Apr | May | Jun | Jul | Aug | Sep | Oct | Nov | Dec |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 2018 | Energy *(GWh)* | 38 | 35 | 36 | 37 | 38 | 72 | 129 | 138 | 59 | 28 | 28 | 30 |
| 2018 | Demand *(MW-Mo)* | 76 | 76 | 62 | 64 | 88 | 191 | 335 | 269 | 126 | 55 | 49 | 53 |
| 2019 | Energy *(GWh)* | 29 | 29 | 27 | 23 | 35 | 45 | 137 | 117 | 60 | 24 | 29 | 29 |
| 2019 | Demand *(MW-Mo)* | 52 | 54 | 57 | 55 | 73 | 155 | 305 | 255 | 208 | 48 | 51 | 47 |

Below summarizes the annual projected energy and demand for each Basin contract.

*Table 39: Annual Projected Energy for Basin Contracts*

| **Energy** *(GWh)* | **2021** | **2022** | **2023** | **2024** | **2025** | **2026** | **2027** | **2028** | **2029** | **2030** |
|---|---|---|---|---|---|---|---|---|---|---|
| **Basin CROD Western Interconnection**[20] | 1575 | 1575 | 1575 | 1580 | 1575 | 1575 | 1575 | 1580 | 1575 | 1575 |
| **Basin Electrically East** [21] | 664 | 683 | 686 | 689 | 692 | 694 | 698 | 701 | 704 | 707 |

*Table 40: Annual Projected Demand for Basin Contracts*

| **Annual Demand** *(Sum of MW-Mo)* | **2021** | **2022** | **2023** | **2024** | **2025** | **2026** | **2027** | **2028** | **2029** | **2030** |
|---|---|---|---|---|---|---|---|---|---|---|
| **Basin CROD Western Interconnection** | 2458 | 2458 | 2458 | 2458 | 2458 | 2458 | 2458 | 2458 | 2458 | 2458 |
| **Basin Electrically East** | 1383 | 1553 | 1559 | 1566 | 1572 | 1579 | 1586 | 1594 | 1600 | 1608 |

*Projected WAPA Contracts – LAP & CRSP Energy & Demand*

LAP and CRSP contracts provide a set amount of energy delivered to each sub region by month. Additionally, an hourly minimum and maximum MW take is provided for each sub region by month. Tri-State is required to schedule on a two-day ahead basis the hydro in each sub region by "dispatching" the energy within the hourly minimum and maximum ranges.

Table 41 below summarizes the annual projected energy and demand for the WAPA CRSP and LAP contracts.

*Table 41: Annual Projected Energy by Contract*

| **Energy** *(GWh)* | **2021** | **2022** | **2023** | **2024** | **2025** | **2026** | **2027** | **2028** | **2029** | **2030** |
|---|---|---|---|---|---|---|---|---|---|---|
| **CRSP Total** | 1424 | 1424 | 1424 | 1424 | 1424 | 1424 | 1424 | 1424 | 1424 | 1424 |
| **Colorado Deliveries** | 930 | 930 | 930 | 930 | 930 | 930 | 930 | 930 | 930 | 930 |
| **New Mexico Deliveries** | 494 | 494 | 494 | 494 | 494 | 494 | 494 | 494 | 494 | 494 |
| **LAP Total** | 900 | 900 | 900 | 900 | 900 | 900 | 900 | 900 | 900 | 900 |
| **Colorado/Wyoming Deliveries** | 711 | 711 | 711 | 711 | 711 | 711 | 711 | 711 | 711 | 711 |
| **Nebraska Deliveries** | 189 | 189 | 189 | 189 | 189 | 189 | 189 | 189 | 189 | 189 |

[20] Energy is delivered to Colorado and Wyoming.
[21] ~15% of this purchase serves Colorado. Balance of purchase serves load in Nebraska. Energy and Demand data is per the 2020 annual load forecast.

*Table 42: Annual Projected Demand by Contract*

| **Annual Demand** [22] *(Sum of MW-Mo)* | **2021** | **2022** | **2023** | **2024** | **2025** | **2026** | **2027** | **2028** | **2029** | **2030** |
|---|---|---|---|---|---|---|---|---|---|---|
| **CRSP Total** | 4807 | 4807 | 4807 | 4807 | 4807 | 4807 | 4807 | 4807 | 4807 | 4807 |
| **Colorado Deliveries** | 3105 | 3105 | 3105 | 3105 | 3105 | 3105 | 3105 | 3105 | 3105 | 3105 |
| **New Mexico Deliveries** | 1702 | 1702 | 1702 | 1702 | 1702 | 1702 | 1702 | 1702 | 1702 | 1702 |
| **LAP Total** | 3823 | 3823 | 3823 | 3823 | 3823 | 3823 | 3823 | 3823 | 3823 | 3823 |
| **Colorado/Wyoming Deliveries** | 3029 | 3029 | 3029 | 3029 | 3029 | 3029 | 3029 | 3029 | 3029 | 3029 |
| **Nebraska Deliveries** | 794 | 794 | 794 | 794 | 794 | 794 | 794 | 794 | 794 | 794 |

## Energy and Capacity Payments for Contract Purchases:

The following rates are averaged over the RAP:

*Table 43: Average Energy and Demand Rates over the Resource Acquisition Period*

| **Resource** | **Energy Rate** *($/MWh)* | **Demand Rate** *($/KW-month)* |
|---|---|---|
| **Basin CROD Western Interconnection** | | |
| **Basin Electrically East** | | |
| **CRSP** | $12.19 | $5.18 |
| **LAP** | $15.72 | $4.12 |
| **Native American WAPA Allocations** | | |
| **Central Valley Electric** | | |

*Table 44: Historical Contract Pricing*

| **Contracts** | **Rate Type** | **2015** | **2016** | **2017** | **2018** | **2019** | **2020** |
|---|---|---|---|---|---|---|---|
| WAPA LAP | Demand Rate ($/kW) | $5.43 | $5.43 | $4.79 | $4.12 | $4.12 | $4.12 |
| | Energy Rate ($/MWh) | $20.71 | $20.71 | $18.28 | $15.72 | $15.72 | $15.72 |
| WAPA CRSP | Demand Rate ($/kW) | $5.18 | $5.18 | $5.18 | $5.18 | $5.18 | $5.18 |
| | Energy Rate ($/MWh) | $12.19 | $12.19 | $12.19 | $12.19 | $12.19 | $12.19 |
| Basin Nebraska | Demand Rate ($/kW) | | | | | | |
| | Energy Rate ($/MWh) | | | | | | |
| Basin CO/WY | Demand Rate ($/kW) | | | | | | |
| | Energy Rate ($/MWh) | | | | | | |
| WAPA Native American Allocations | Average Energy Rate ($/MWh) | | | | | | |
| WAPA Resource Balancing Purchase | Energy Rate ($/MWh) | | | | | | |
| Central Valley Electric | Average Energy Rate ($/MWh) | | | | | | |
| PNM UC | Energy Rate ($/MWh) | | | | | | |
| PRPA - Rawhide Solar SS | Energy Rate ($/MWh) | | | | | | |
| PRPA - Prairie Solar SS | Energy Rate ($/MWh) | | | | | | |
| PRPA - Roundhouse Wind SS | Energy Rate ($/MWh) | | | | | | |
| CSU - Palmer Solar SS | Energy Rate ($/MWh) | | | | | | |

[22] Representative of monthly billing demands per the contracts. Actual maximum available hourly capacity in any given month varies.
[23] Composite rate encompassing energy and demand components
[24] Composite rate encompassing energy and demand components

# 7 Phase II RFP

See Attachment Vol II 7-1 Phase II All-Source RFP.

See Attachment Vol II 7-2 Bidder Highly Confidential Non-Disclosure Agreement.

For model contracts, see the following attachments:

- Attachment Vol II 7-3 Dispatchable PPA
- Attachment Vol II 7-4 Semi-Dispatchable PPA
- Attachment Vol II 7-5 Renewable PPA

# List of Acronyms

| | |
|---|---|
| ACE | Affordable Clean Energy Rule |
| APR | Annual Progress Report |
| ARIMA | Auto Regressive Integrated Moving Average |
| BA | Balancing Authority |
| BE | Beneficial Electrification |
| BEPC | Basin Electric Power Cooperative |
| BHCE | Black Hills Colorado Electric, Inc. |
| BHCT | Black Hills Colorado Transmission |
| B&V | Black & Veatch |
| CAISO | California Independent System Operator |
| CE | Capacity Expansion |
| $CO_2$ | Carbon dioxide |
| CR | $CO_2$ Reduction |
| CRN | Cooperative Research Network |
| CRSP | Colorado River Storage Project |
| CSU | Colorado Springs Utility |
| DER | Distributed Energy Resources |
| DG | Distributed Generation |
| DOE | Department of Energy |
| DR | Demand Response |
| DSM | Demand Side Management |
| ECO | Eastern Colorado |
| EE | Energy Efficiency |
| EIA | Energy Information Administration |
| ELCC | Effective Load Carrying Capability |
| EPA | Environmental Protection Agency |
| ERPI | Electric Research Power Institute |
| ERP | Electric Resource Plan |
| EV | Electric Vehicle |
| FERC | Federal Energy Regulatory Commission |
| GHG | Greenhouse Gases |
| Hg | Mercury |
| IRP | Integrated Resource Plan |
| ISO | Independent System Operator |
| LAP | Loveland Area Projects |
| LAPT | WAPA Rocky Mountain Region Loveland Area Projects |
| LCoE | Levelized Cost of Energy |
| LGIP | Large Generation Interconnection Process |
| LOLP | Loss of Load Probability |
| LRS | Laramie River Station |

| | |
|---|---|
| MBPP | Missouri Basin Power Project |
| MCP | Member Coincident Peak |
| M-RETS | Midwest Renewable Energy Tracking System |
| NERC | North American Reliability Corporation |
| NREL | National Renewable Energy Laboratories |
| $NO_x$ | Nitrogen Oxides |
| NRECA | Nation Rural Electric Cooperative Association |
| OATT | Open Access Transmission Tariff |
| PAC | PacifiCorp |
| POI | Point of Interconnection |
| PM | Particulate Matter |
| PR | Partial Requirements |
| PPA | Power Purchase Agreement |
| PSCo | Public Service of Colorado |
| PNM | Public Service of New Mexico |
| PO | Portfolio Optimization |
| POD | Point of Delivery |
| PRPA | Platte River Power Authority |
| PVRR | Prevent Value Revenue Requirement |
| QRU | Qualifying Retail Utility |
| QWU | Qualifying Wholesale Utility |
| RAP | Resource Acquisition Period |
| REC | Renewable Energy Credit |
| REP | Responsible Energy Plan |
| RES | Renewable Energy Standard |
| RFP | Request for Proposal |
| RPP | Resource Planning Period |
| RPS | Renewable Portfolio Standard |
| RTO | Regional Transmission Organization |
| SCC | Social Cost of Carbon (Scenario) |
| SCoC | Social Cost of Carbon |
| SIP | Regional Haze State Implementation Plan |
| $SO_2$ | Sulfur Dioxide |
| SPP | Southwest Power Pool |
| SPV 3 | Springerville Unit 3 |
| SRP | Salt River Project |
| SRSG | Southwest Reserve Sharing Group |
| TA | Transmission Area |
| TEP | Tucson Electric Power |
| TP | Transmission Provider |
| WACM | Western Area Colorado Missouri |
| WAPA | Western Area Power Administration |
| WCO | Western Colorado |

| | |
|---|---|
| WEIM | Western Energy Imbalance Market |
| WEIS | Western Energy Imbalance Service |
| WMPA | Wyoming Municipal Power Agency |
| WREGIS | Western Renewable Energy General Information System |

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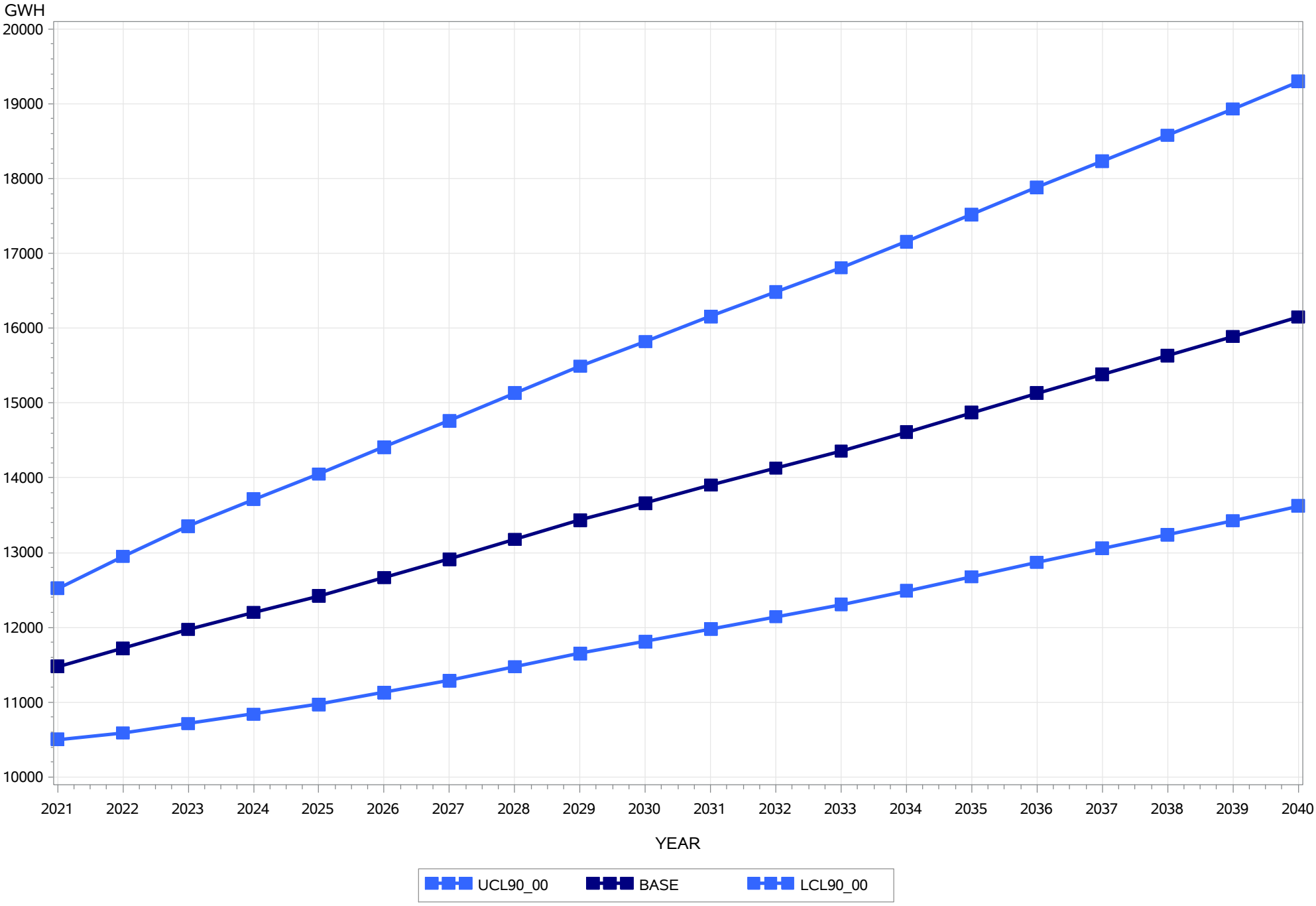
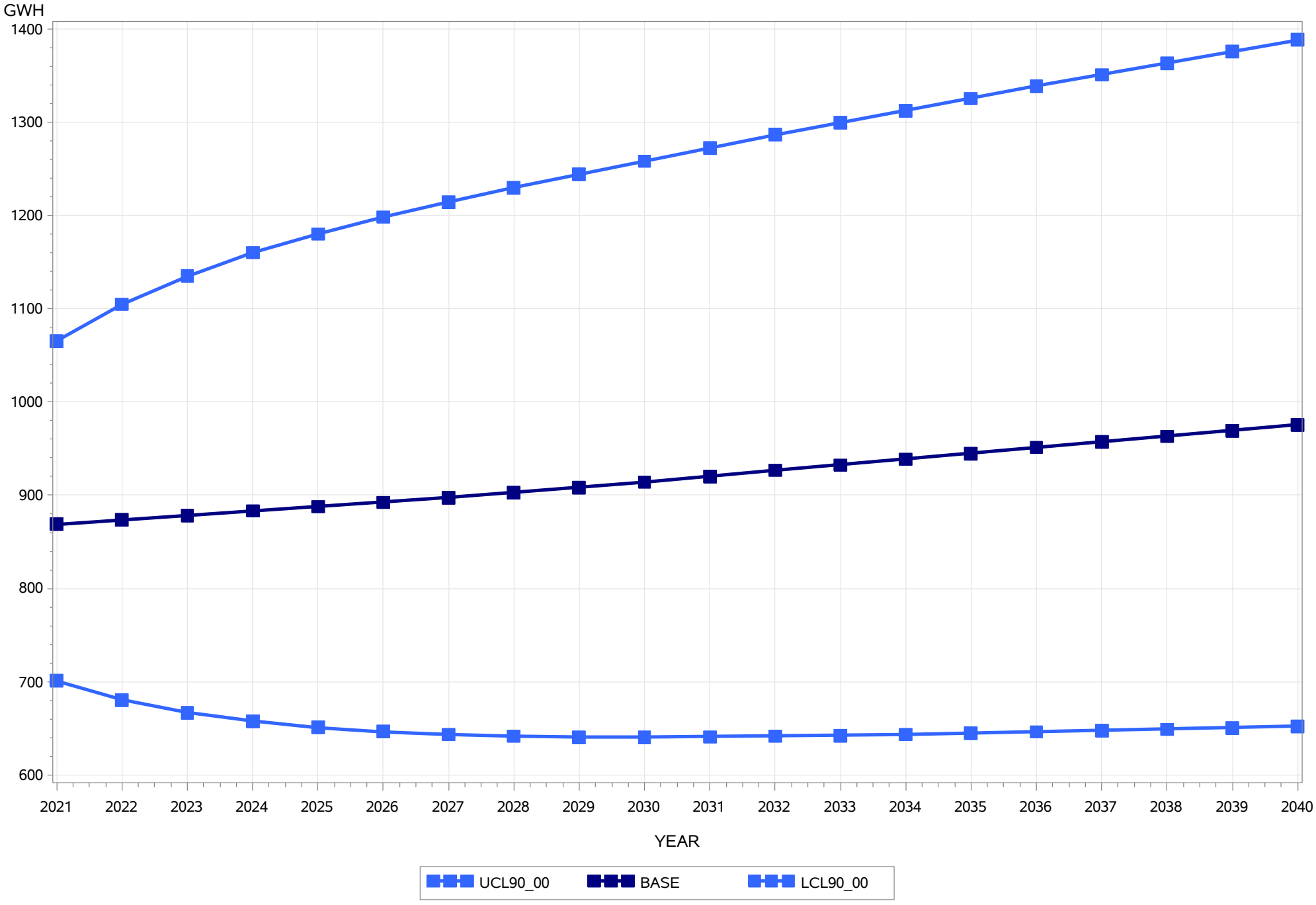
# Total Annual Energy Sales
## STATE OF COLORADO



# Total Annual Energy Sales
## STATE OF NEBRASKA



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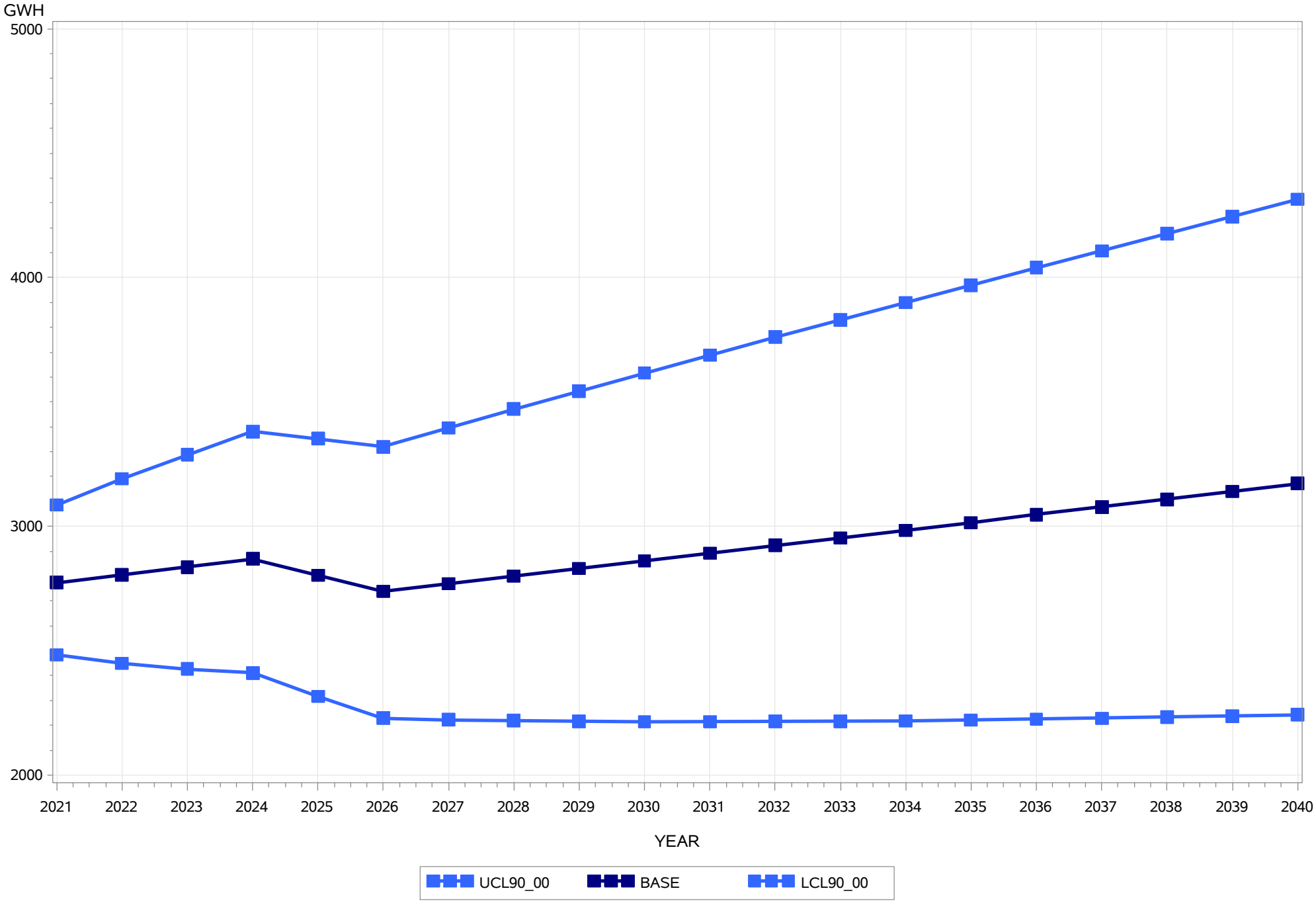
# Total Annual Energy Sales
## STATE OF NEW MEXICO



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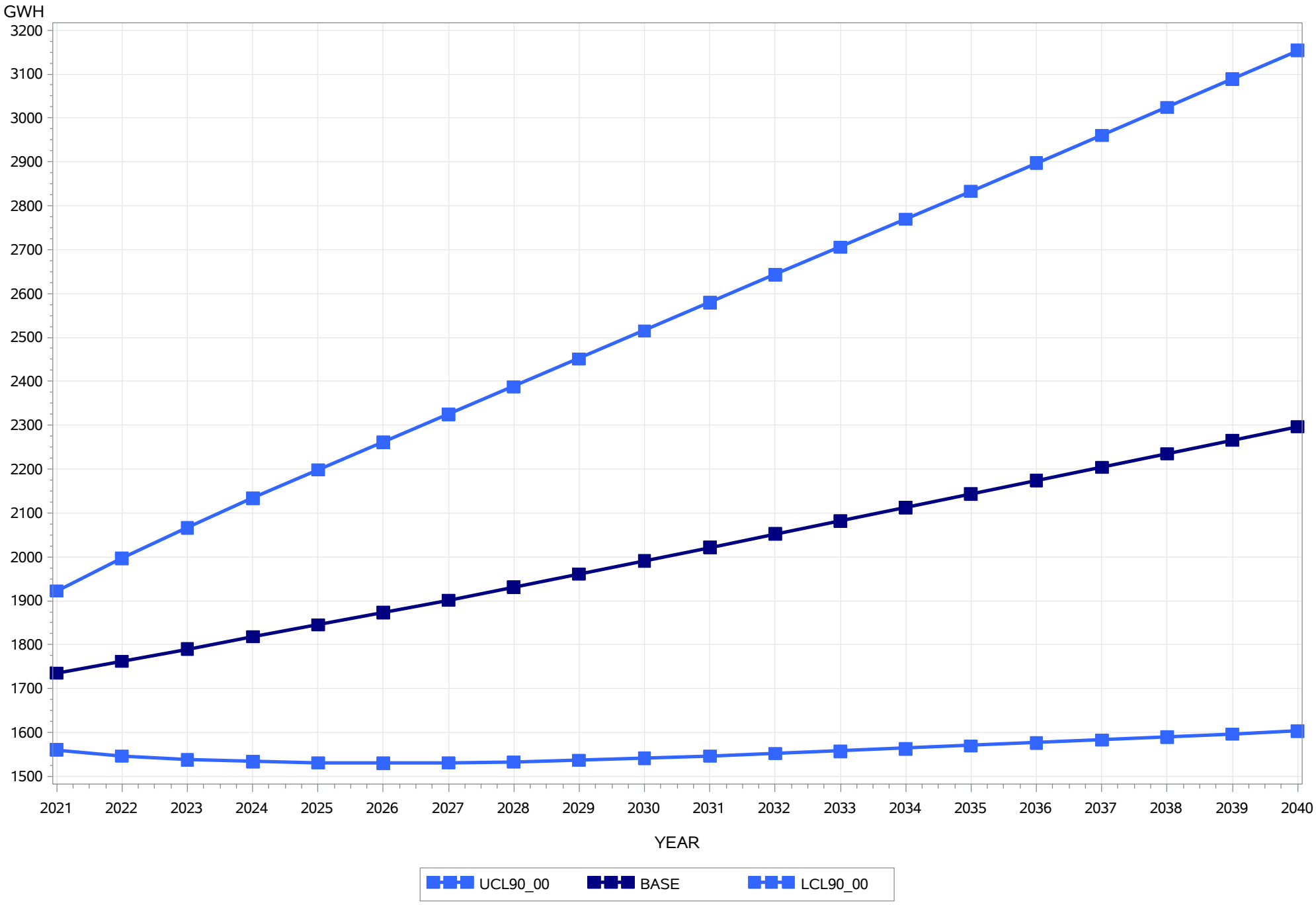
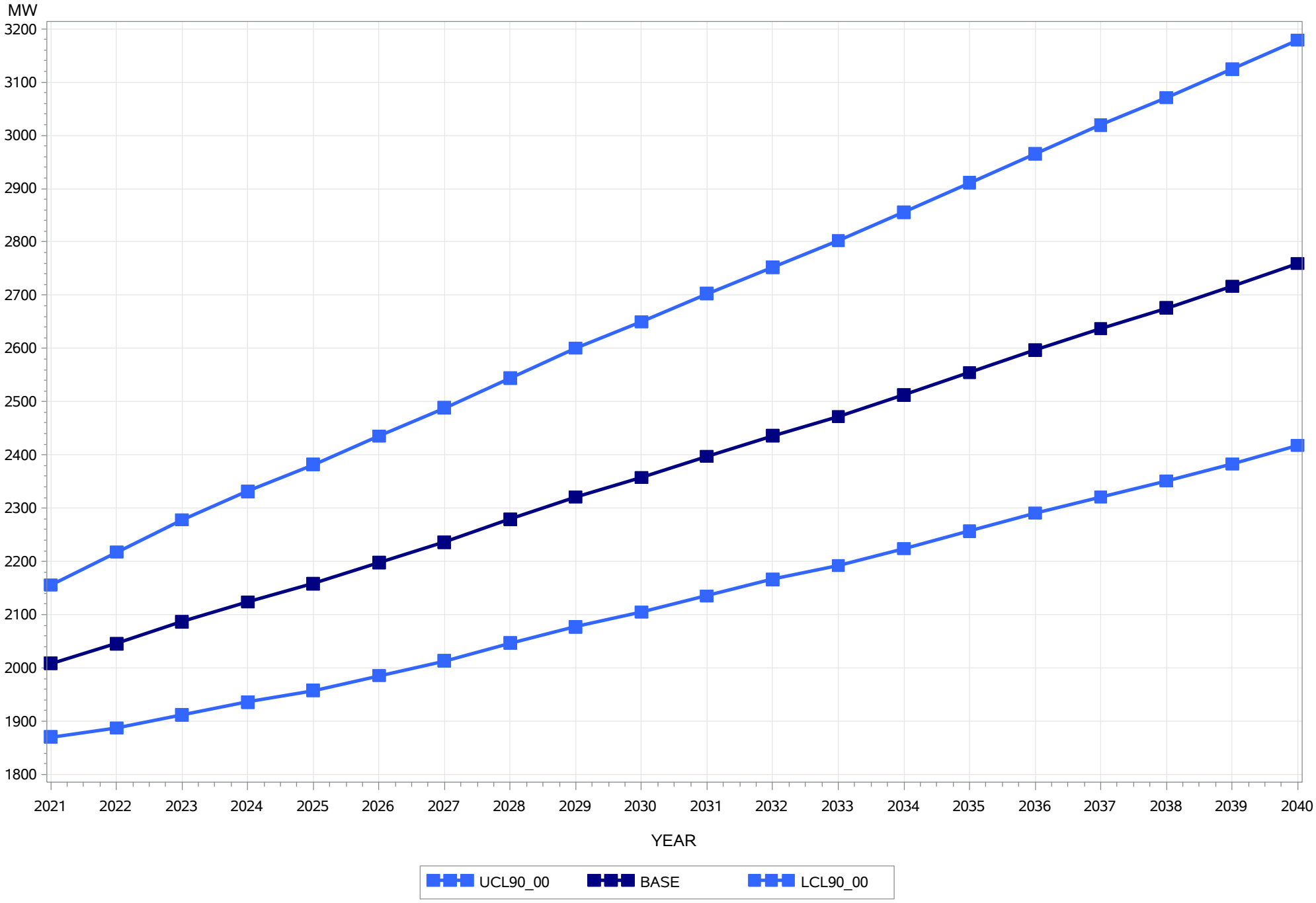
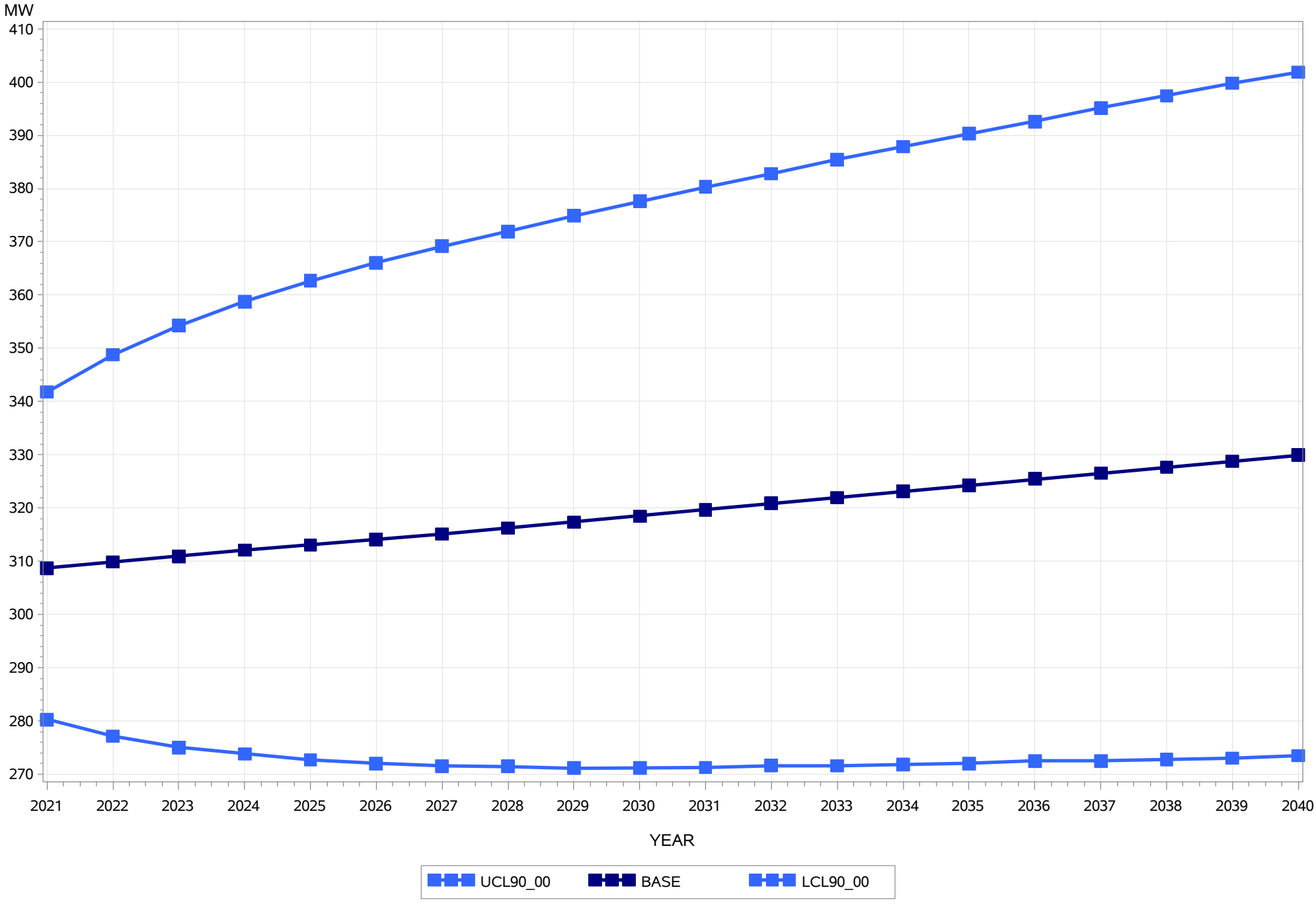
# Total Annual Energy Sales
## STATE OF WYOMING



# Annual Summer Coincident Peak
## STATE OF COLORADO



# Annual Summer Coincident Peak
## STATE OF NEBRASKA



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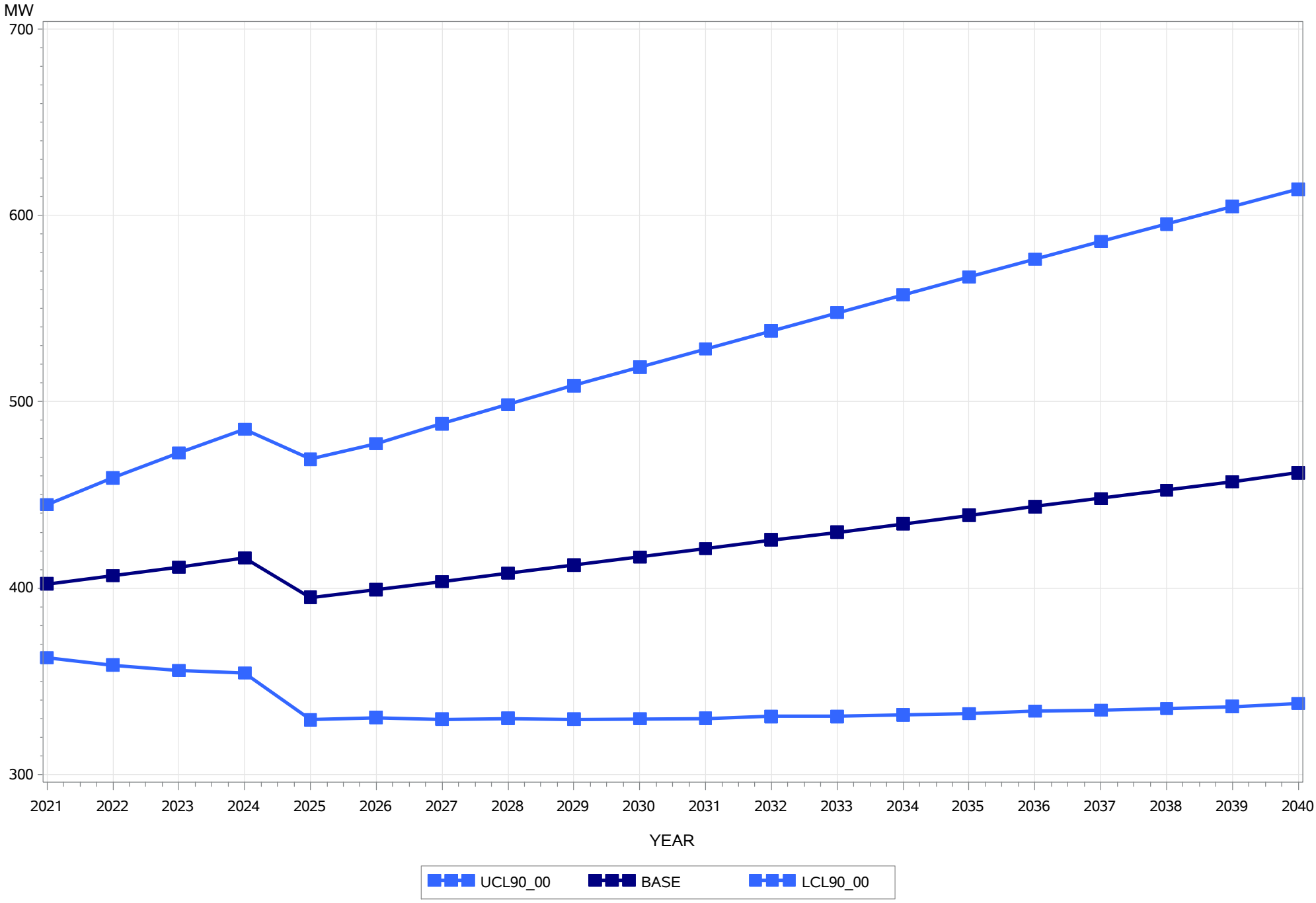
# Annual Summer Coincident Peak
## STATE OF NEW MEXICO



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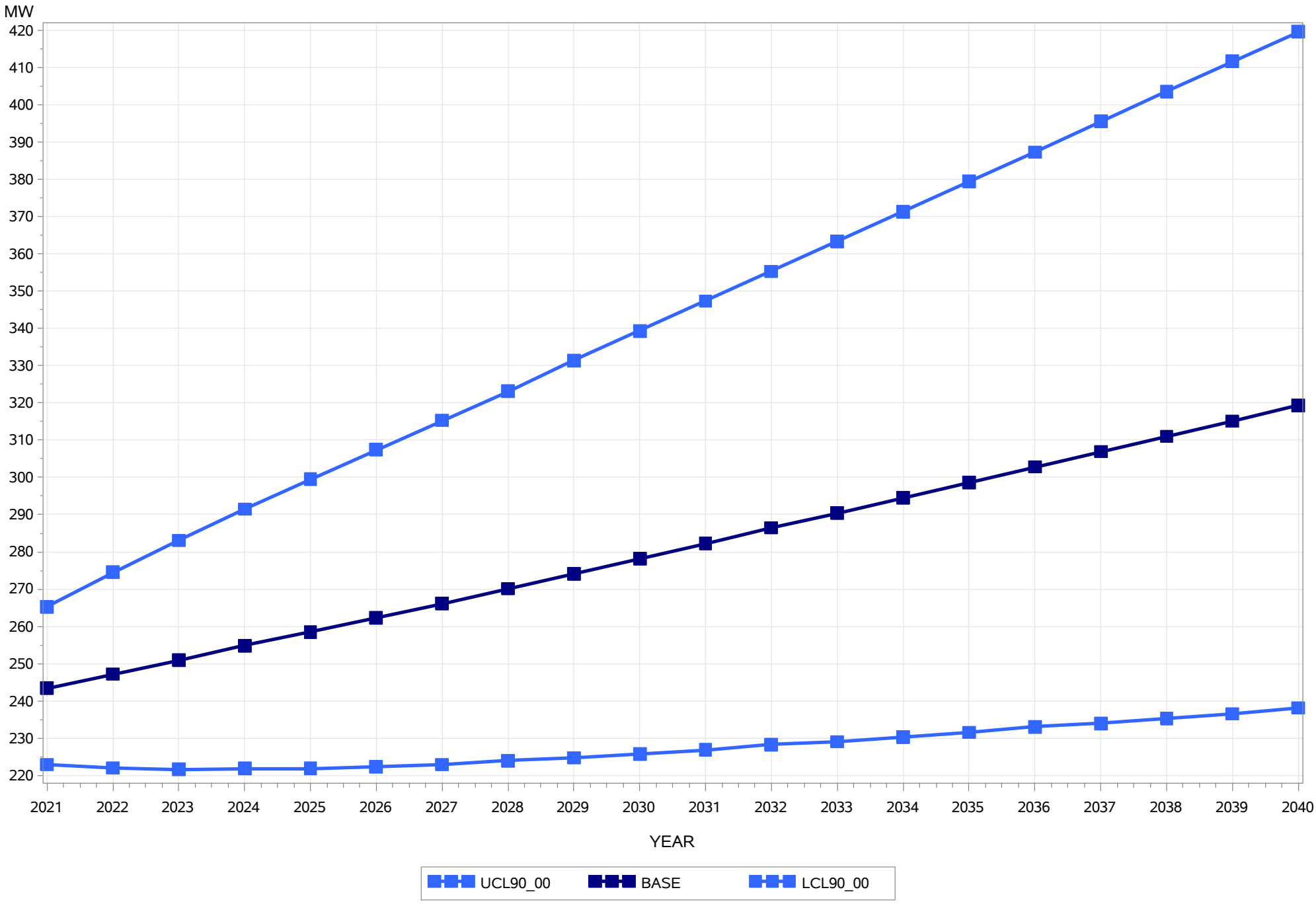

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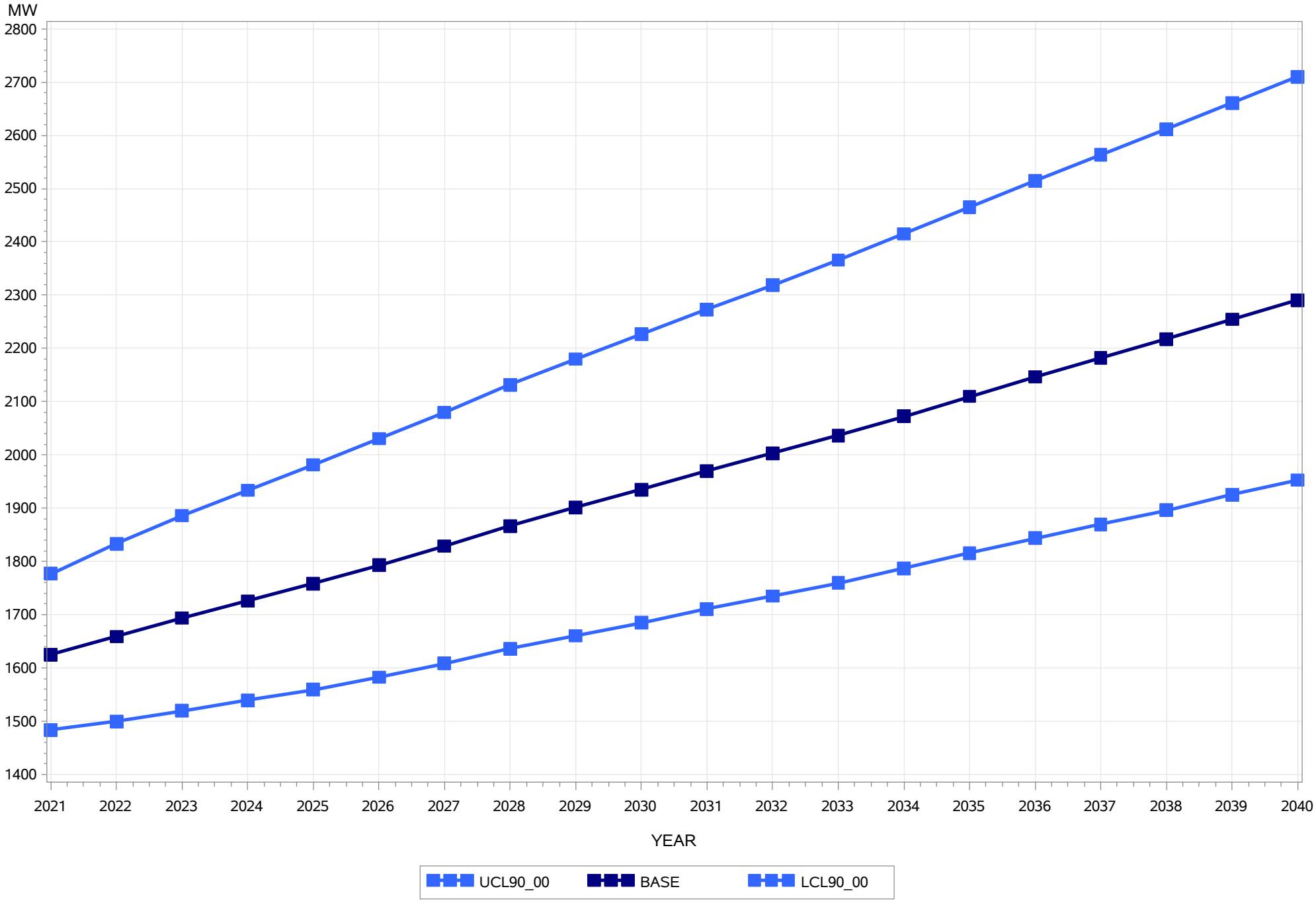
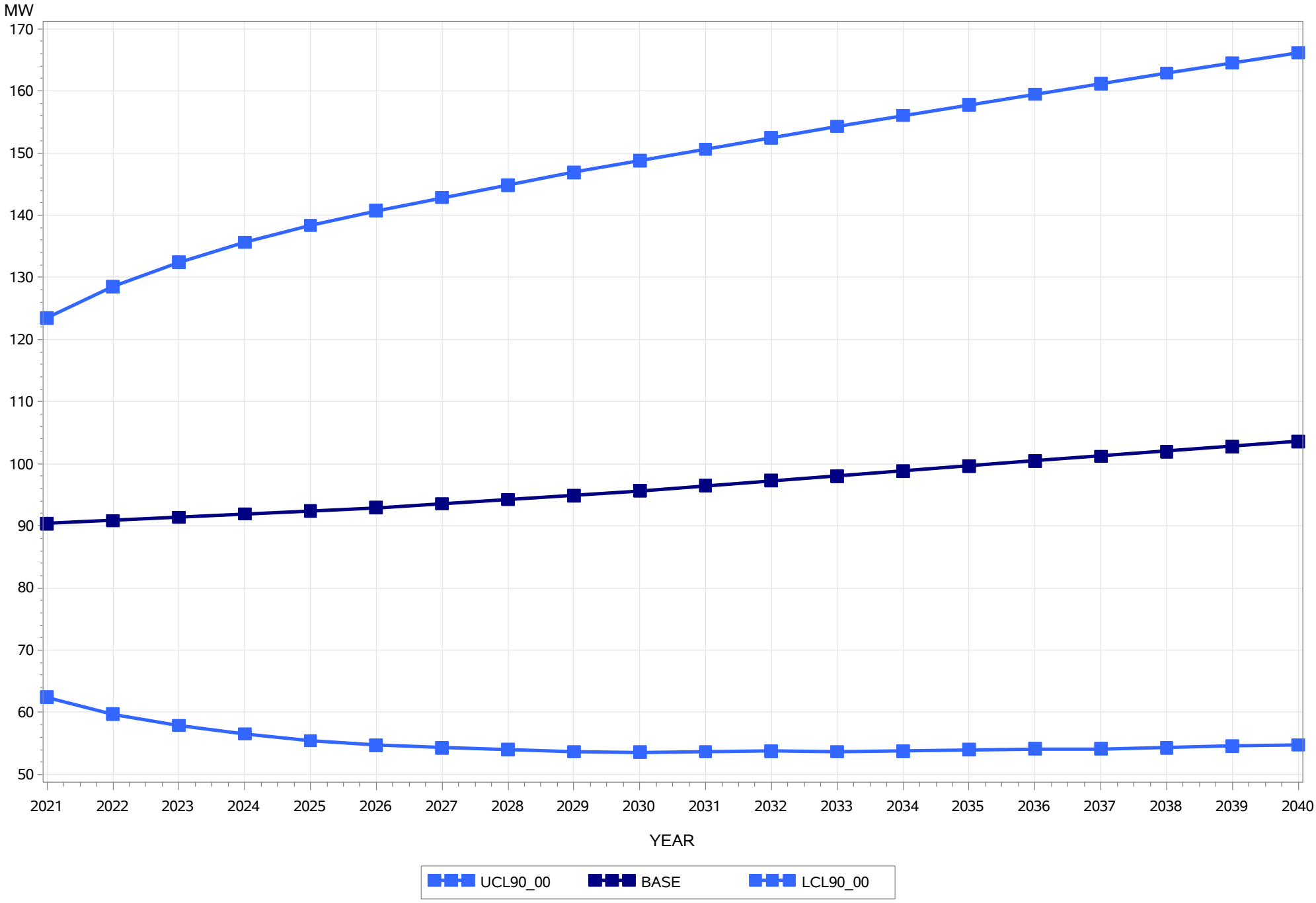
## STATE OF COLORADO



# Annual Winter Coincident Peak
## STATE OF NEBRASKA



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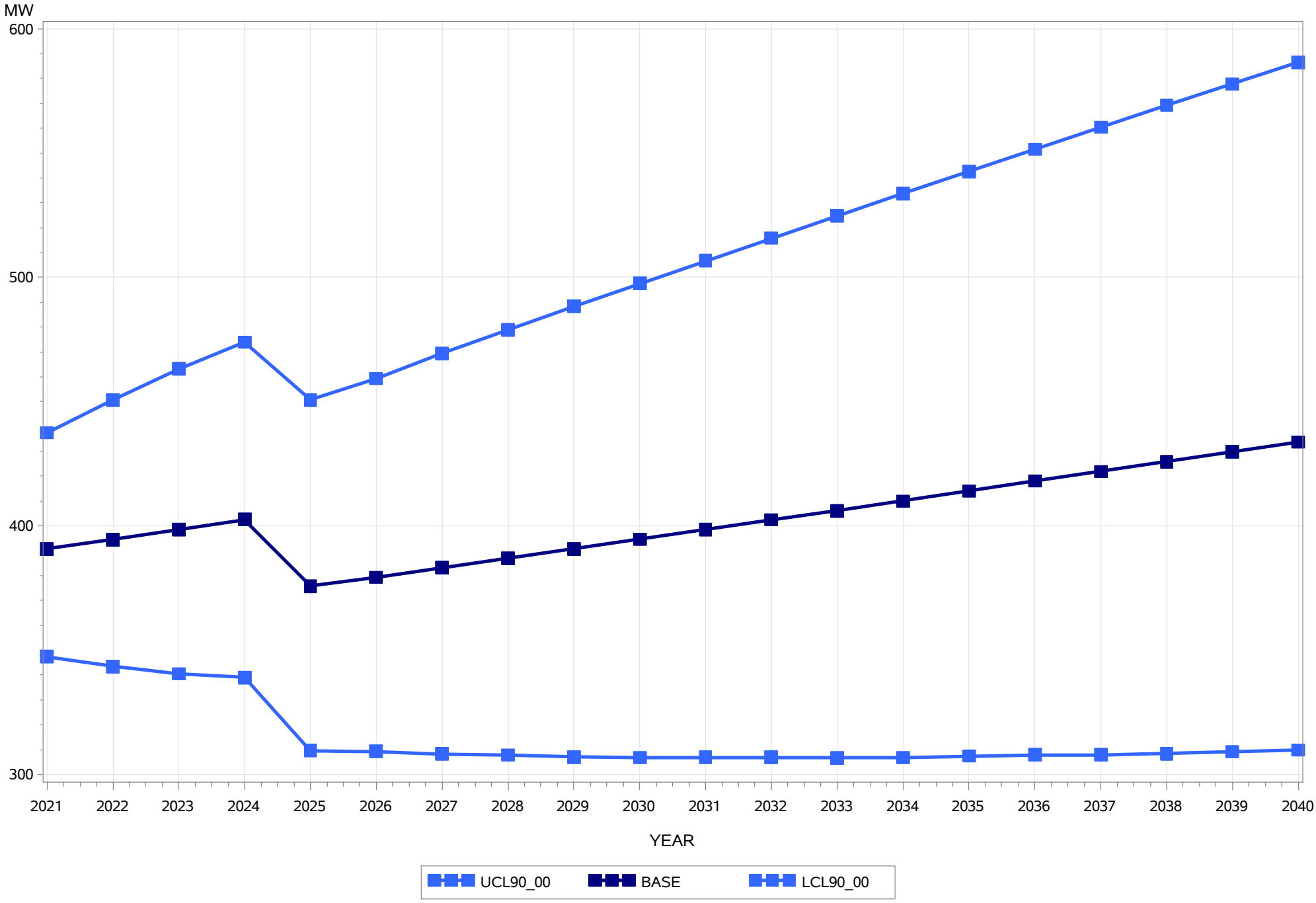
# Annual Winter Coincident Peak
## STATE OF NEW MEXICO



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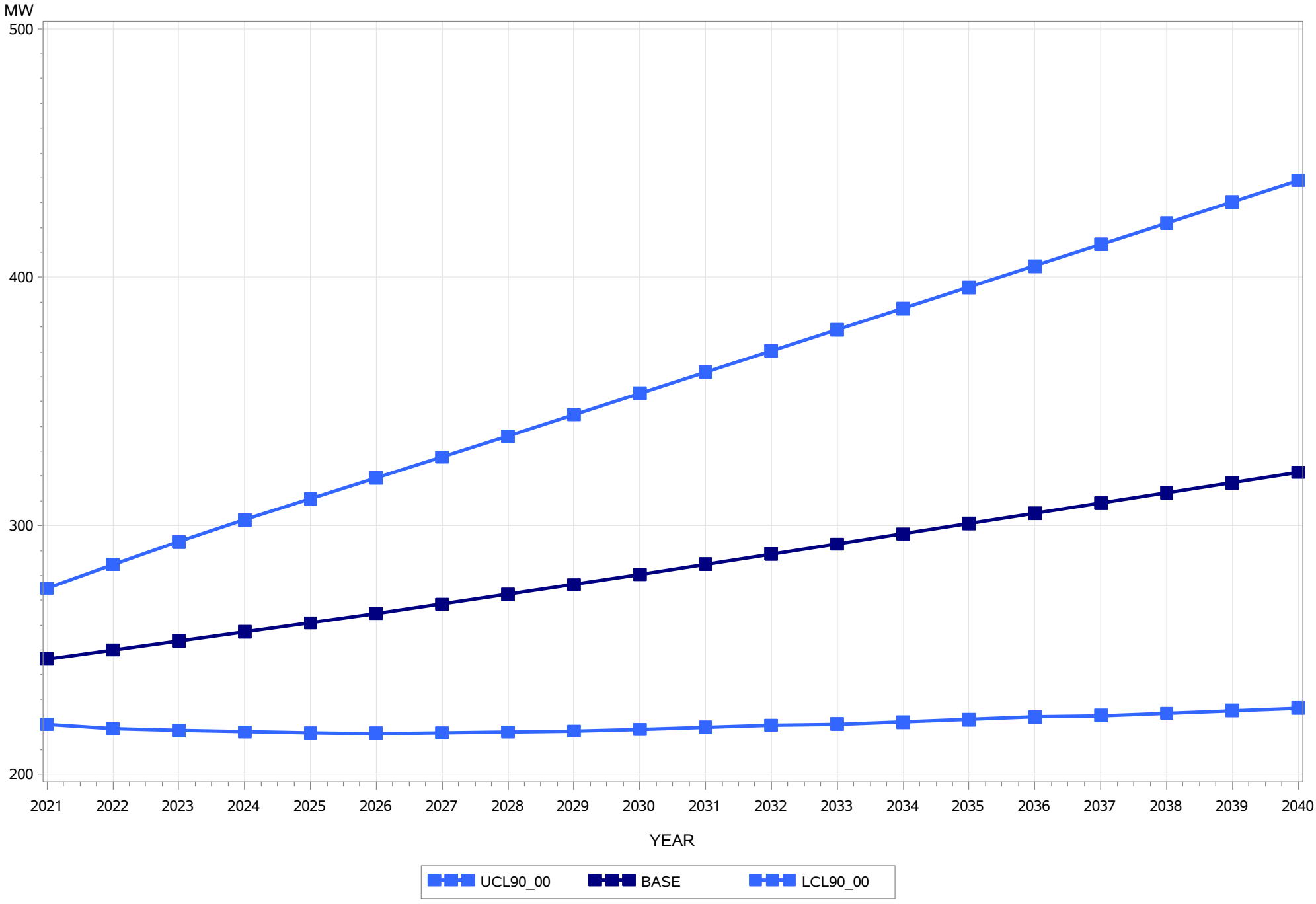
## STATE OF WYOMING



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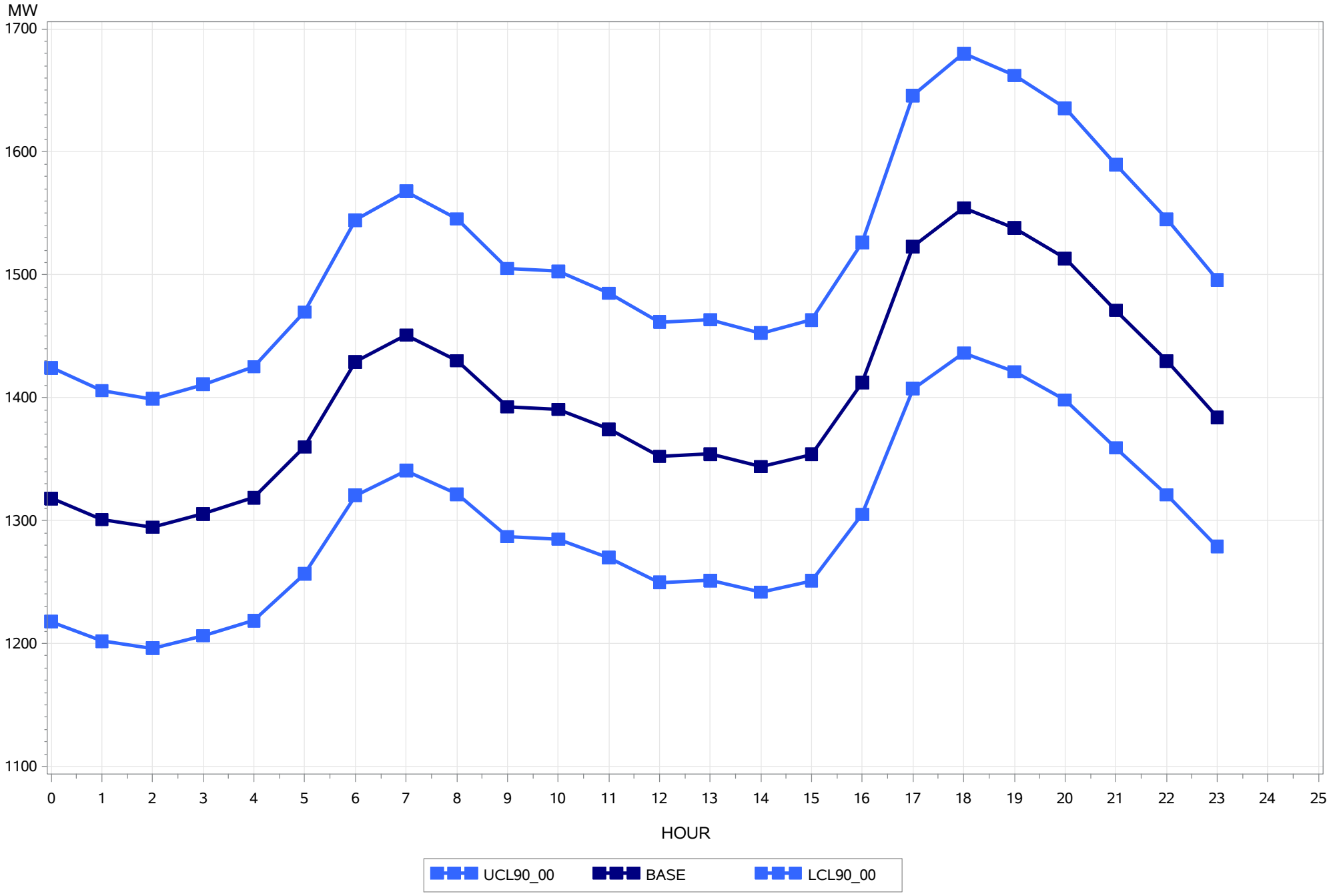
# Member Forecasted On Peak Demand Day for January 2021

**STATE OF COLORADO**

**Date of On Peak Day - 01/06/2021**



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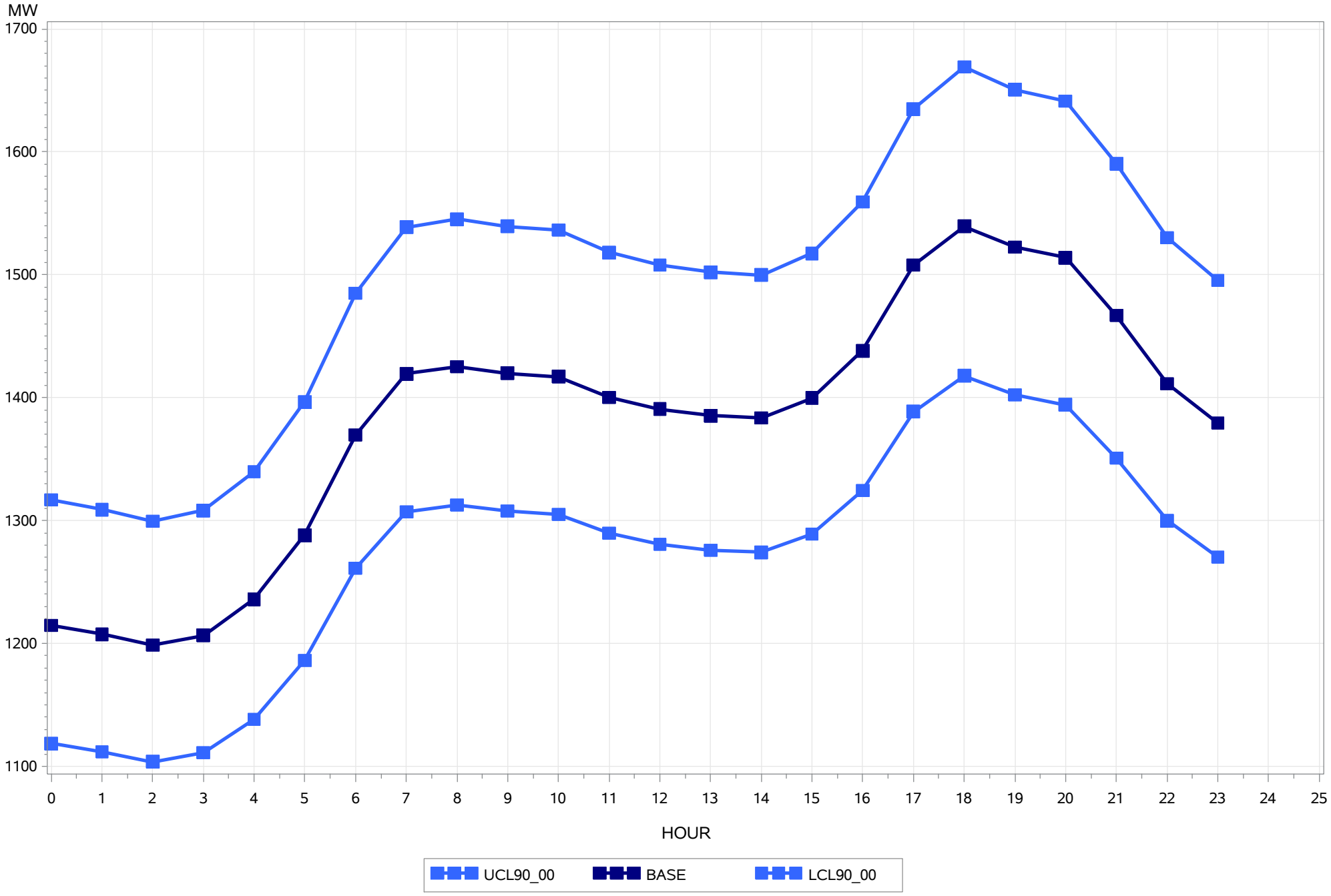
**STATE OF COLORADO**

**Date of On Peak Day - 02/01/2021**



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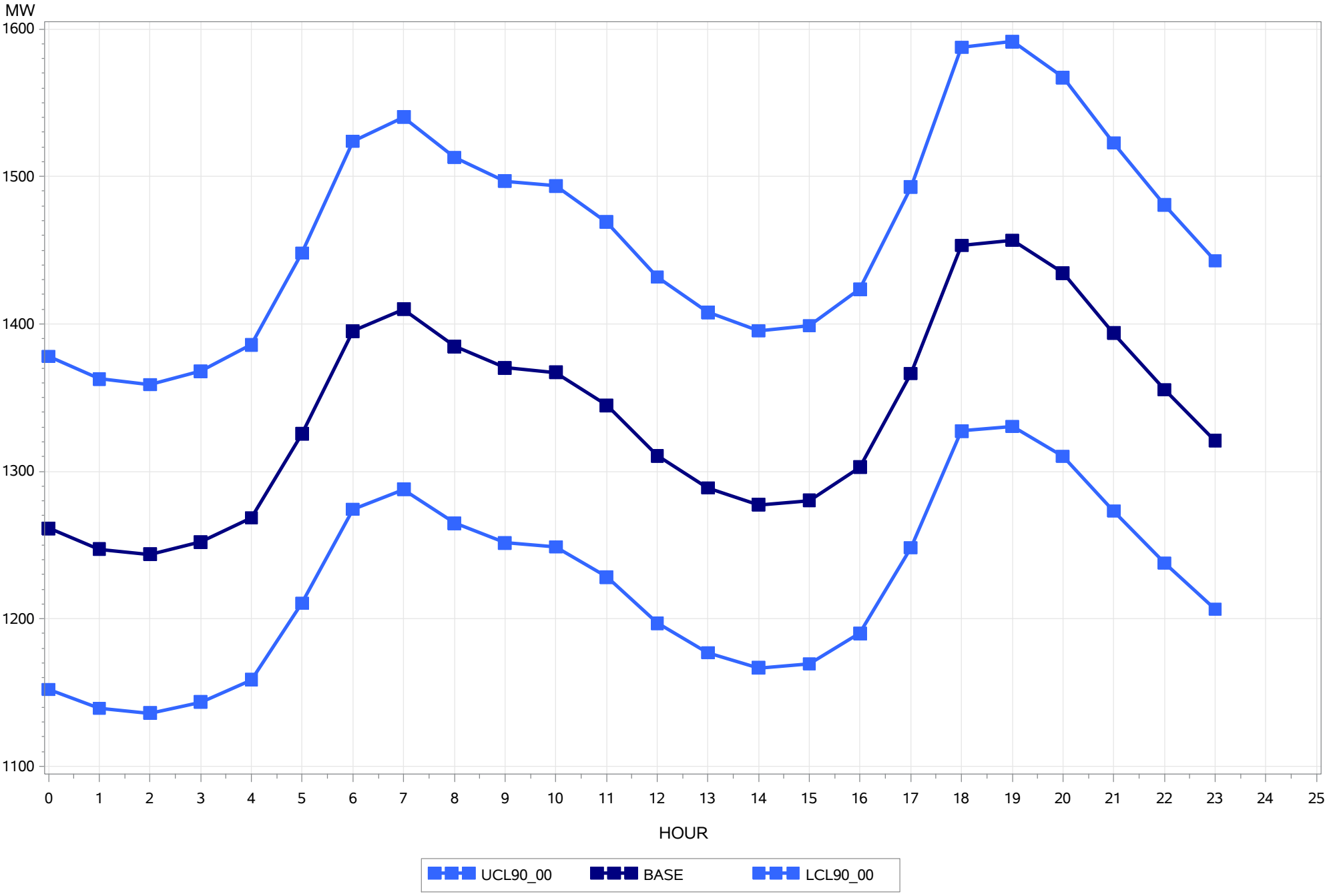
## STATE OF COLORADO

## Date of On Peak Day - 03/01/2021



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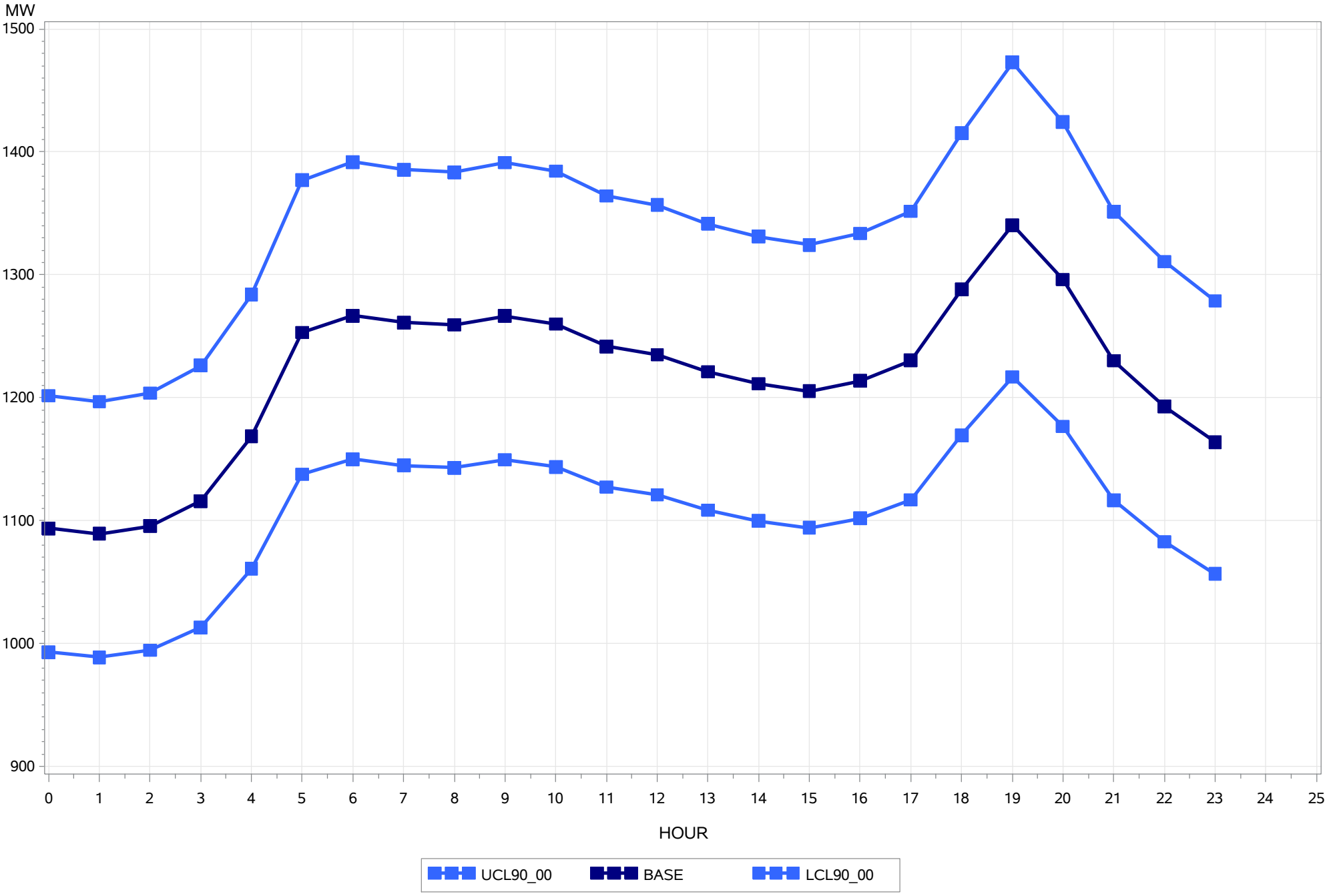
# Member Forecasted On Peak Demand Day for April 2021

**STATE OF COLORADO**

**Date of On Peak Day - 04/15/2021**



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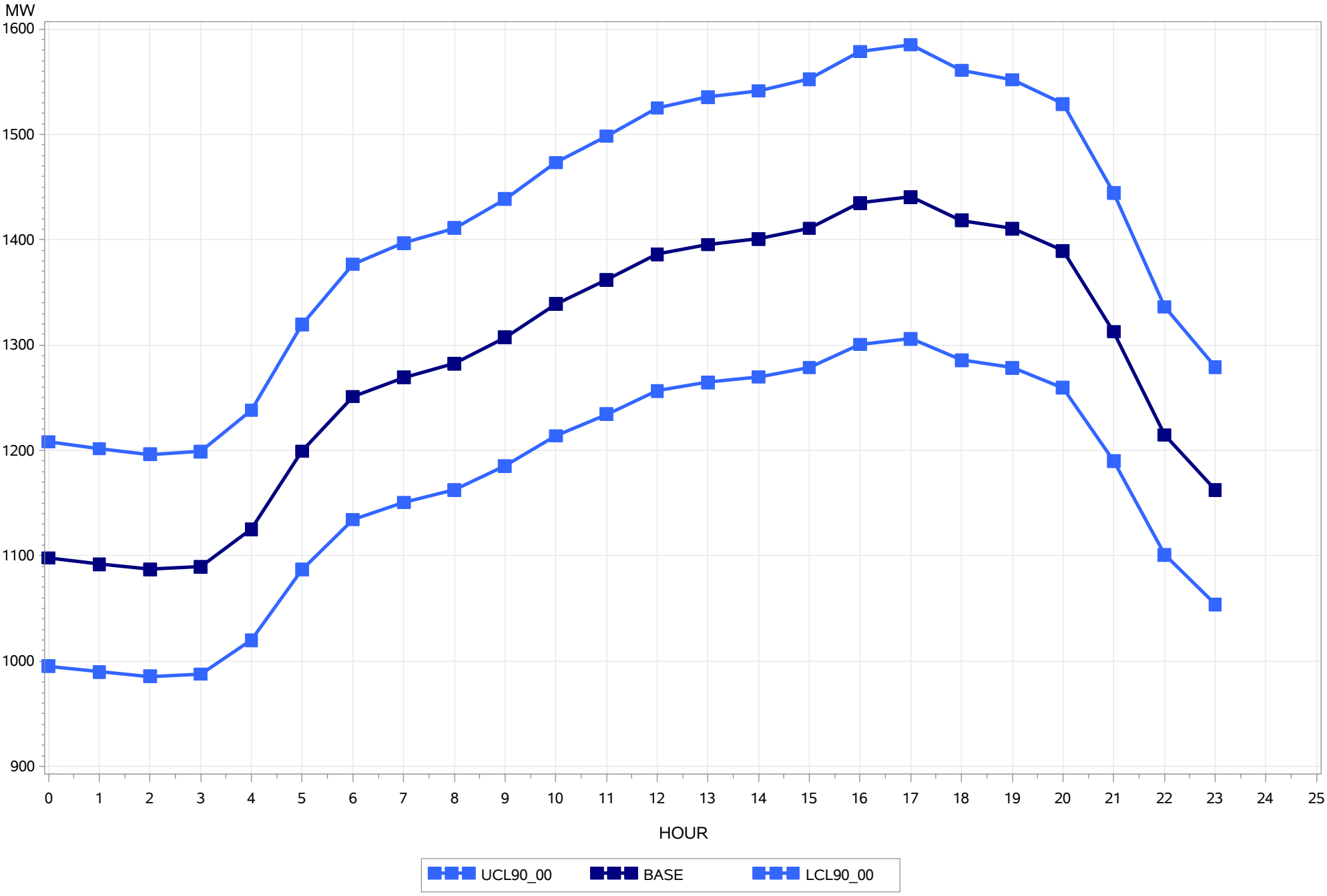
# Member Forecasted On Peak Demand Day for May 2021

## STATE OF COLORADO

## Date of On Peak Day - 05/31/2021



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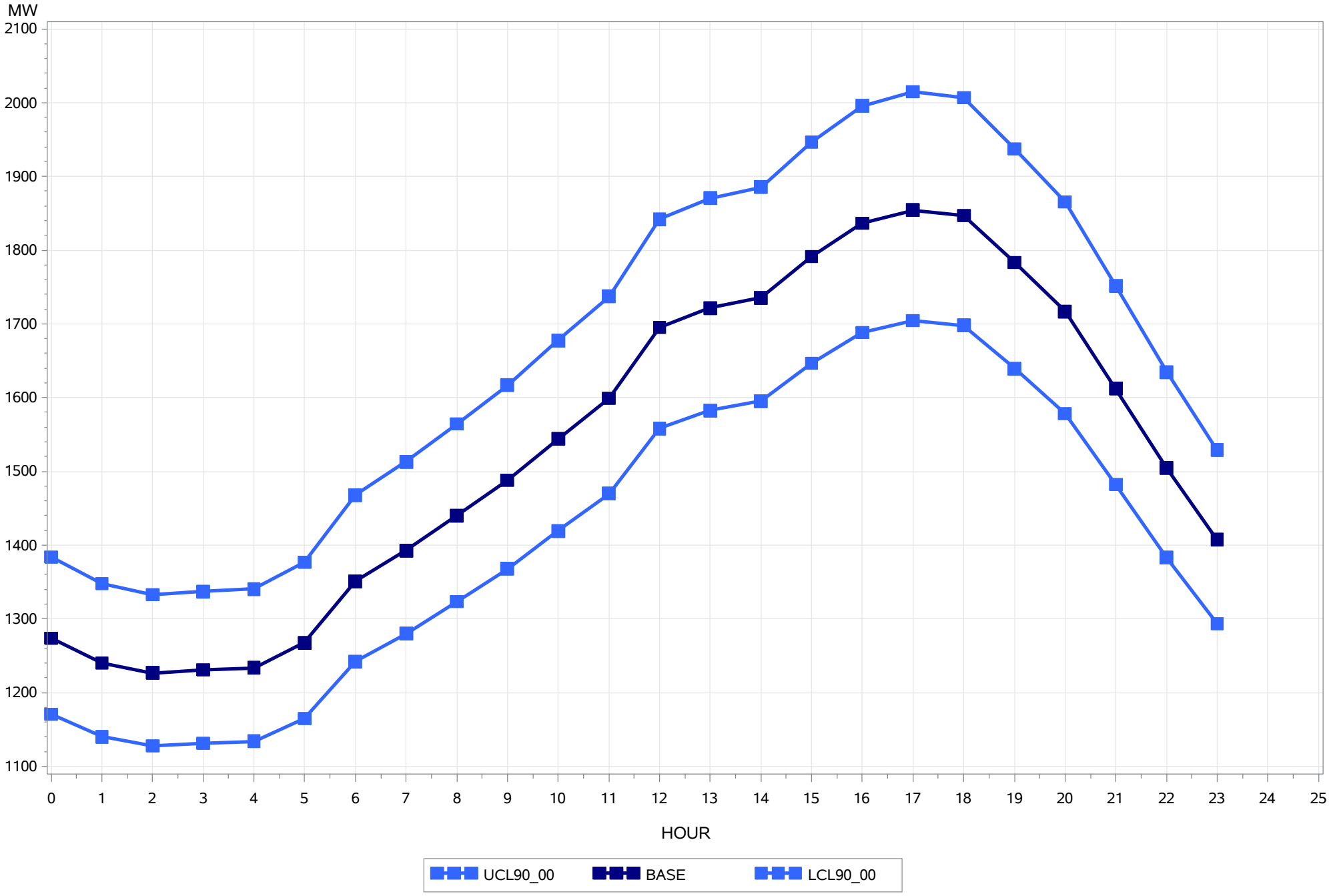
# Member Forecasted On Peak Demand Day for June 2021

## STATE OF COLORADO

## Date of On Peak Day - 06/28/2021



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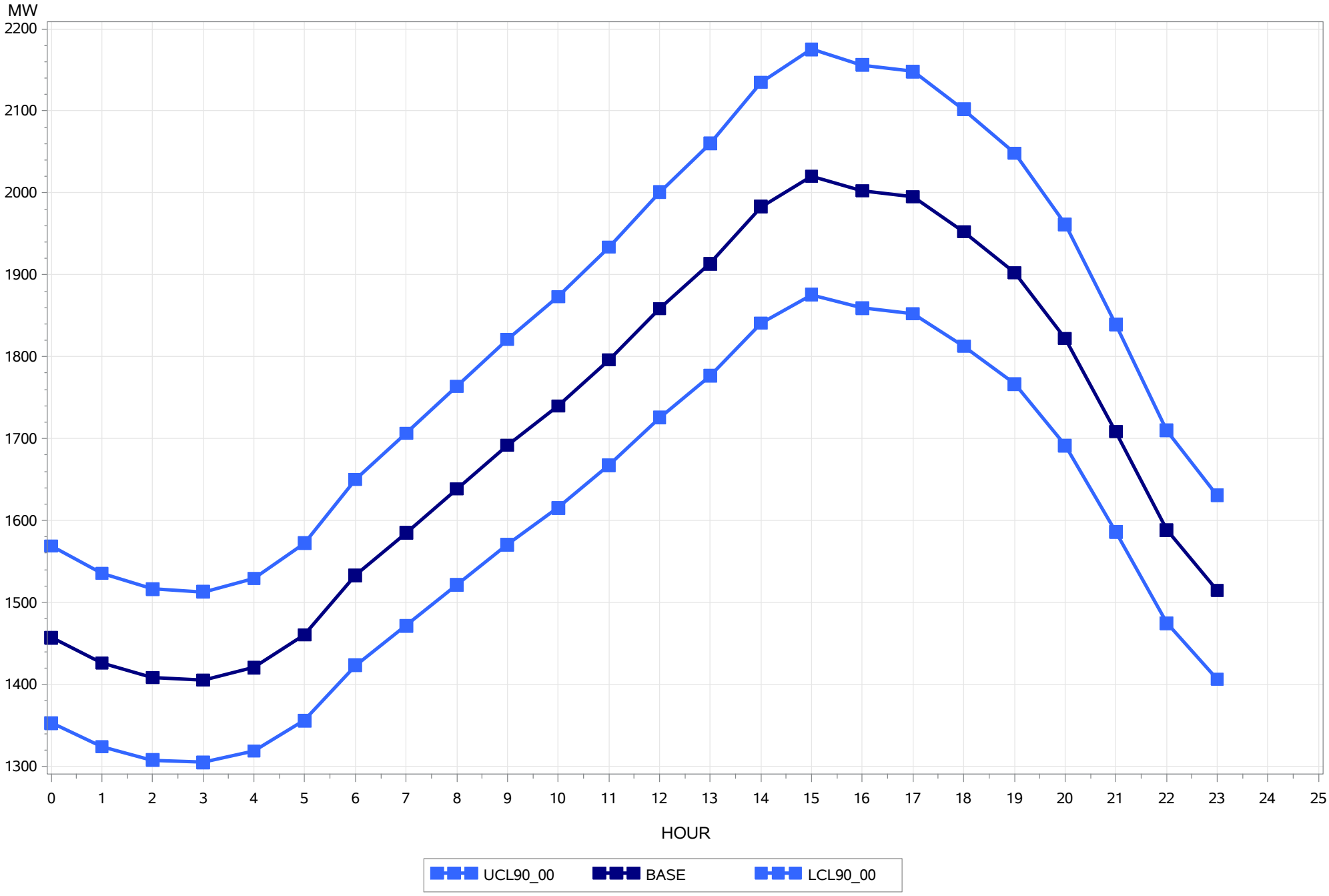
# Member Forecasted On Peak Demand Day for July 2021

## STATE OF COLORADO

## Date of On Peak Day - 07/22/2021



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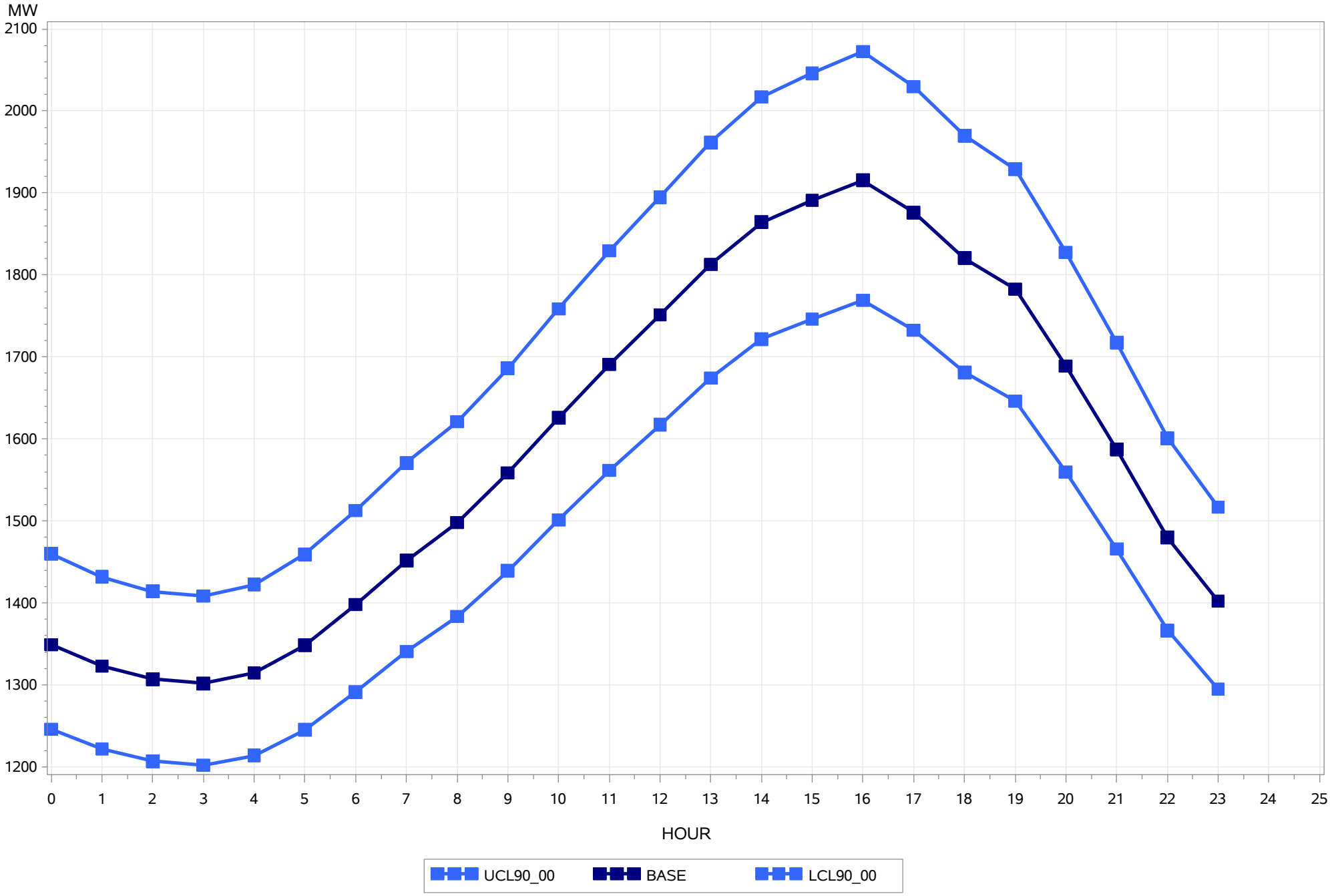
# Member Forecasted On Peak Demand Day for August 2021

## STATE OF COLORADO

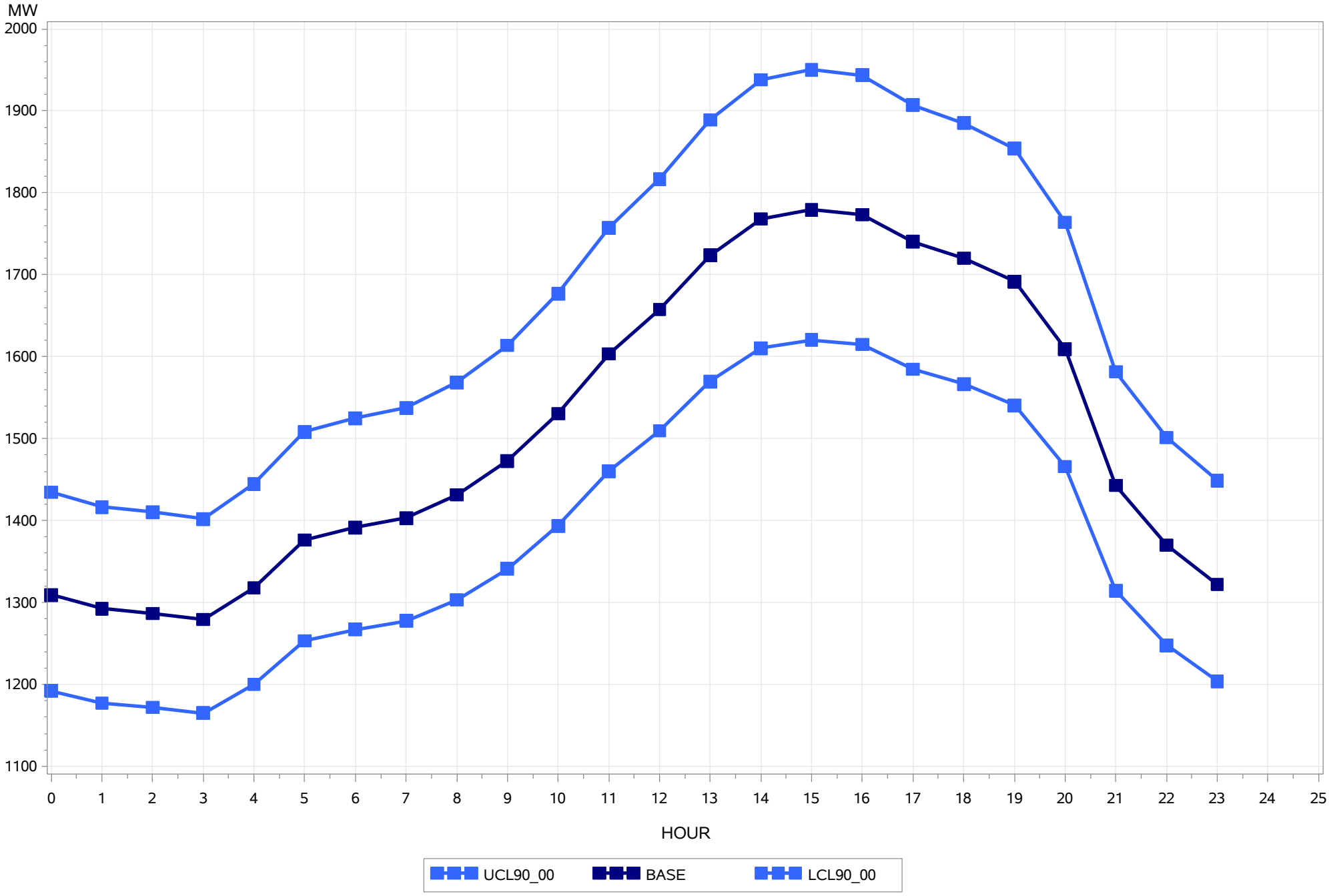
## Date of On Peak Day - 08/28/2021



# Member Forecasted On Peak Demand Day for September 2021

**STATE OF COLORADO**

**Date of On Peak Day - 09/01/2021**



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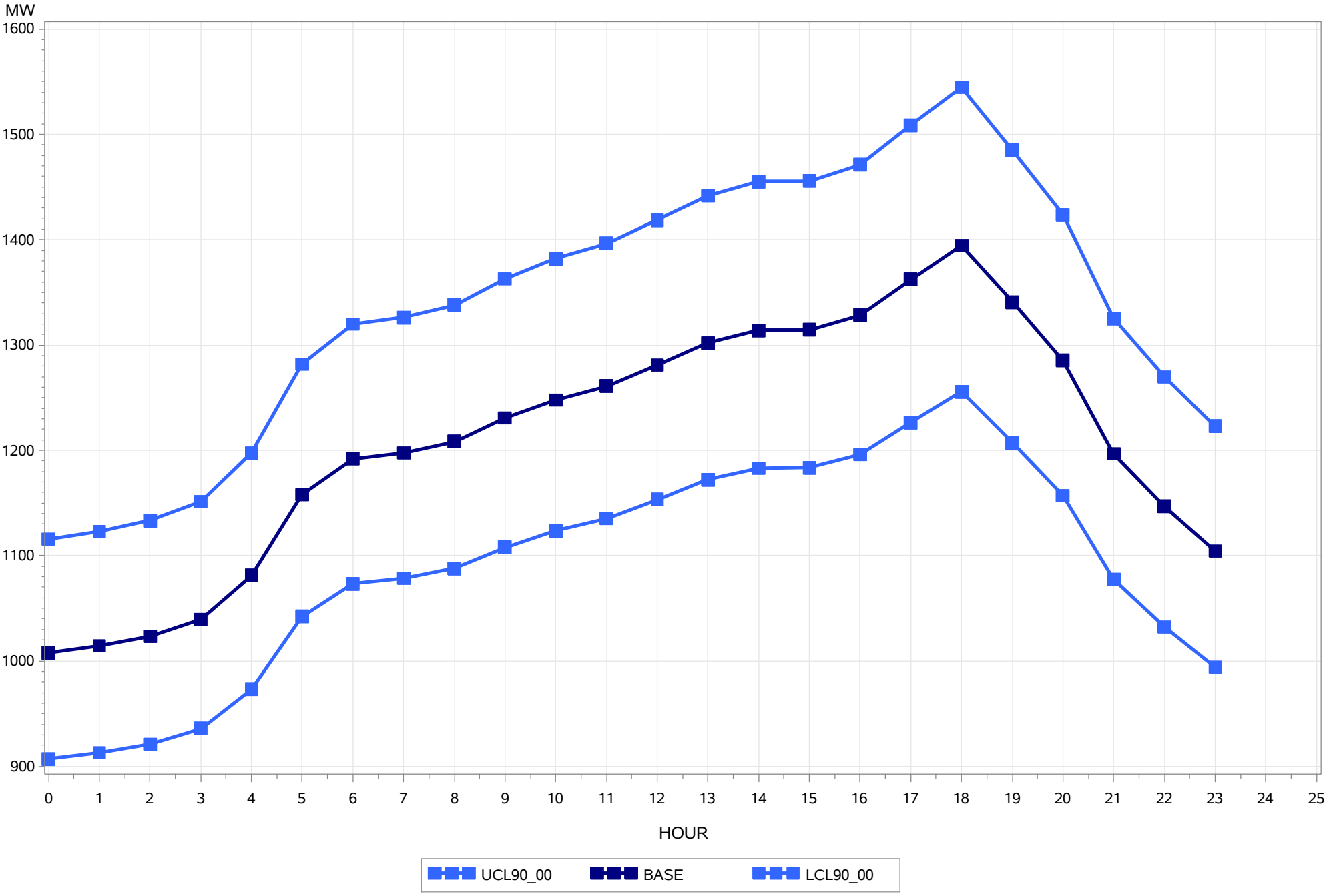
# Member Forecasted On Peak Demand Day for October 2021

**STATE OF COLORADO**

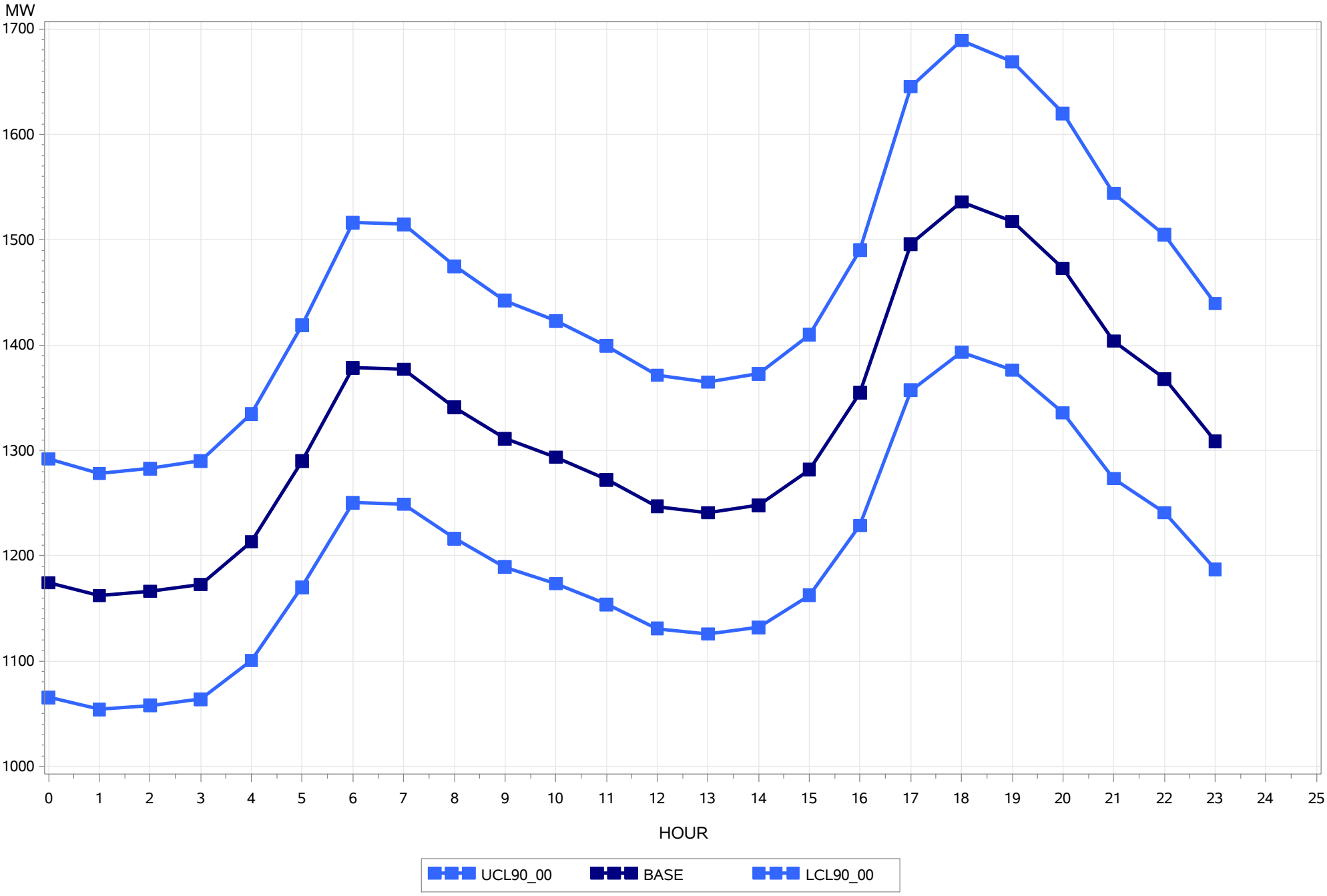
**Date of On Peak Day - 10/11/2021**



# Member Forecasted On Peak Demand Day for November 2021

**STATE OF COLORADO**

**Date of On Peak Day - 11/08/2021**



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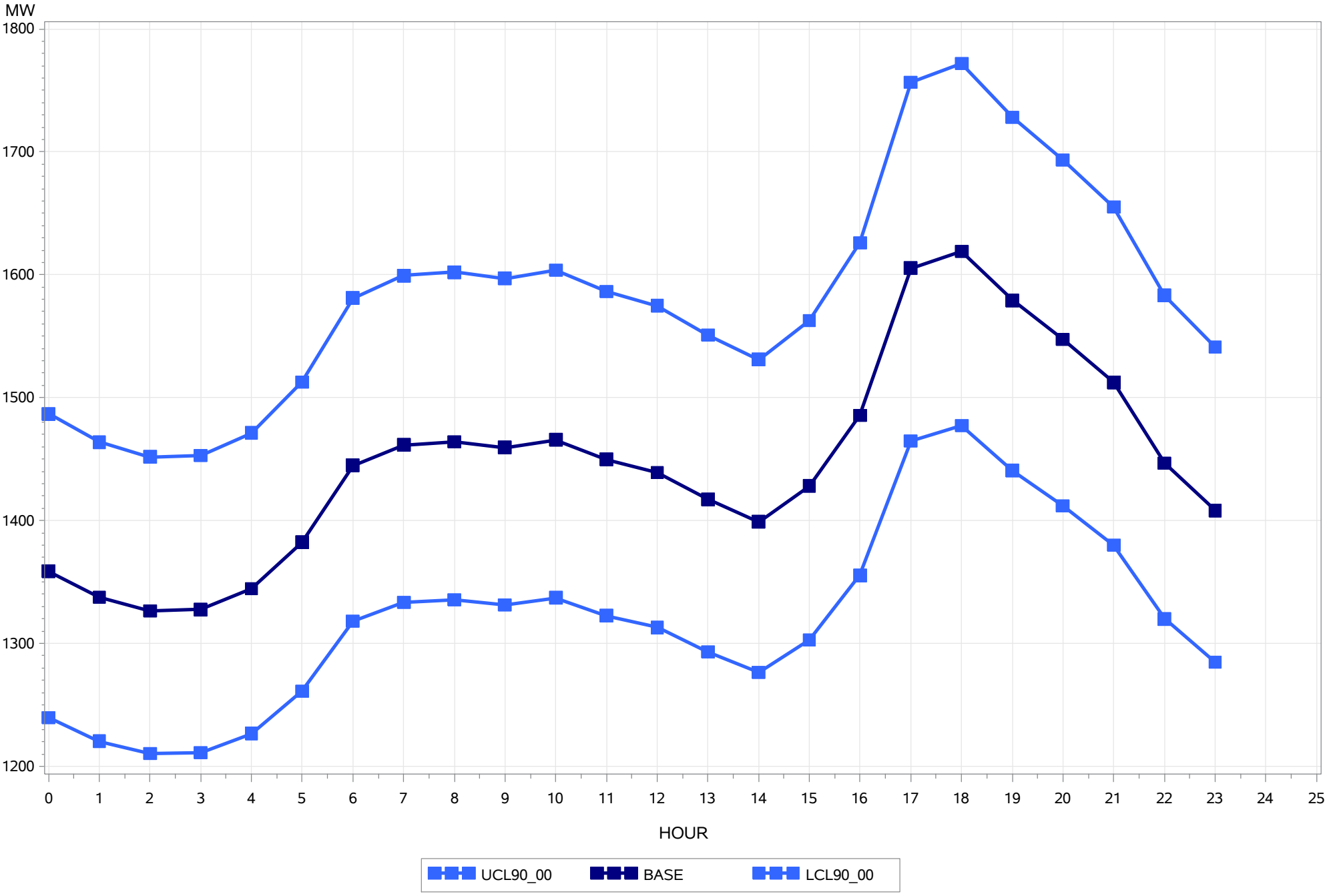
**STATE OF COLORADO**

**Date of On Peak Day - 12/28/2021**



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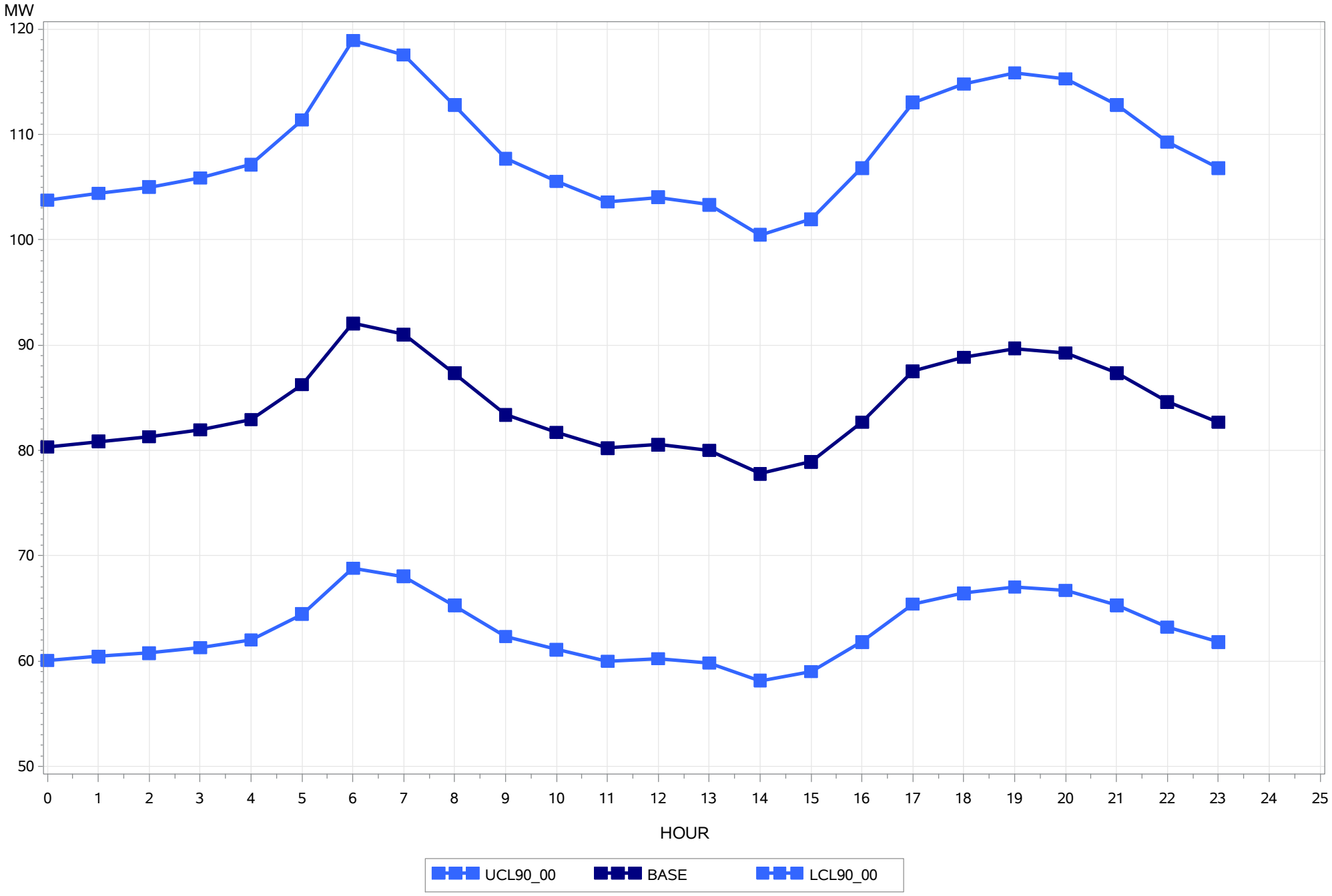
# Member Forecasted On Peak Demand Day for January 2021

**STATE OF NEBRASKA**

**Date of On Peak Day - 01/07/2021**



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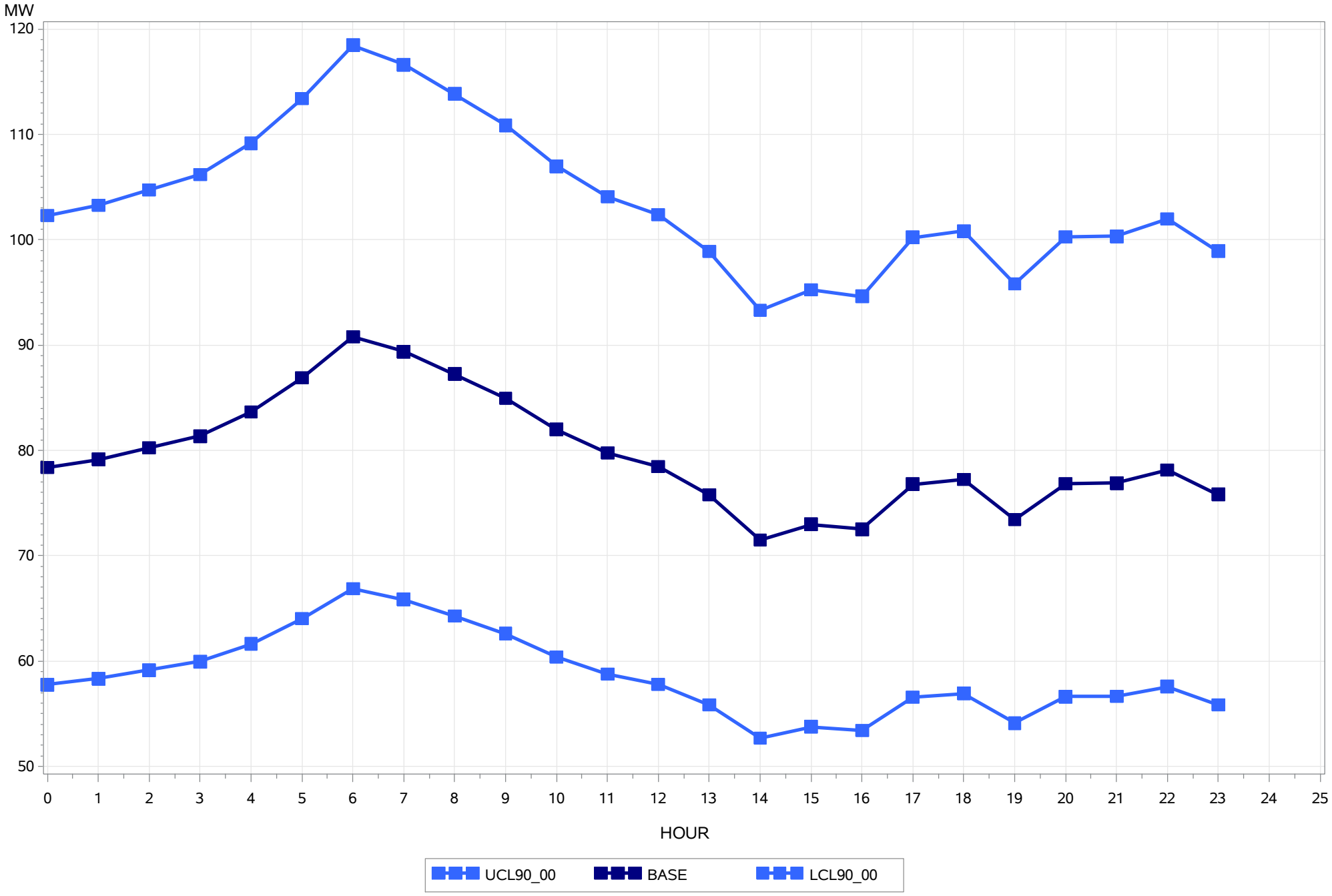
# Member Forecasted On Peak Demand Day for February 2021

**STATE OF NEBRASKA**

**Date of On Peak Day - 02/03/2021**



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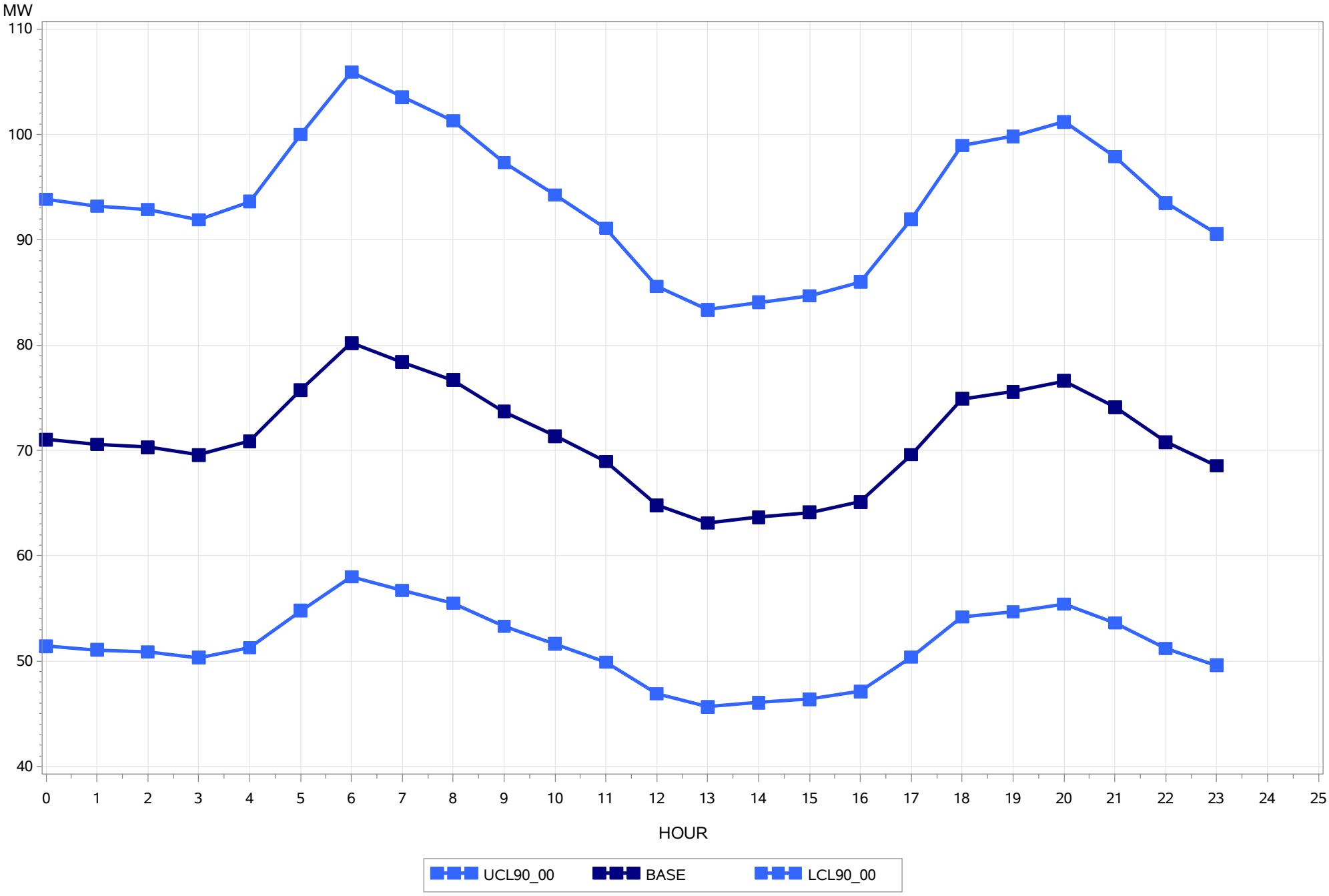
# Member Forecasted On Peak Demand Day for March 2021

## STATE OF NEBRASKA

## Date of On Peak Day - 03/02/2021



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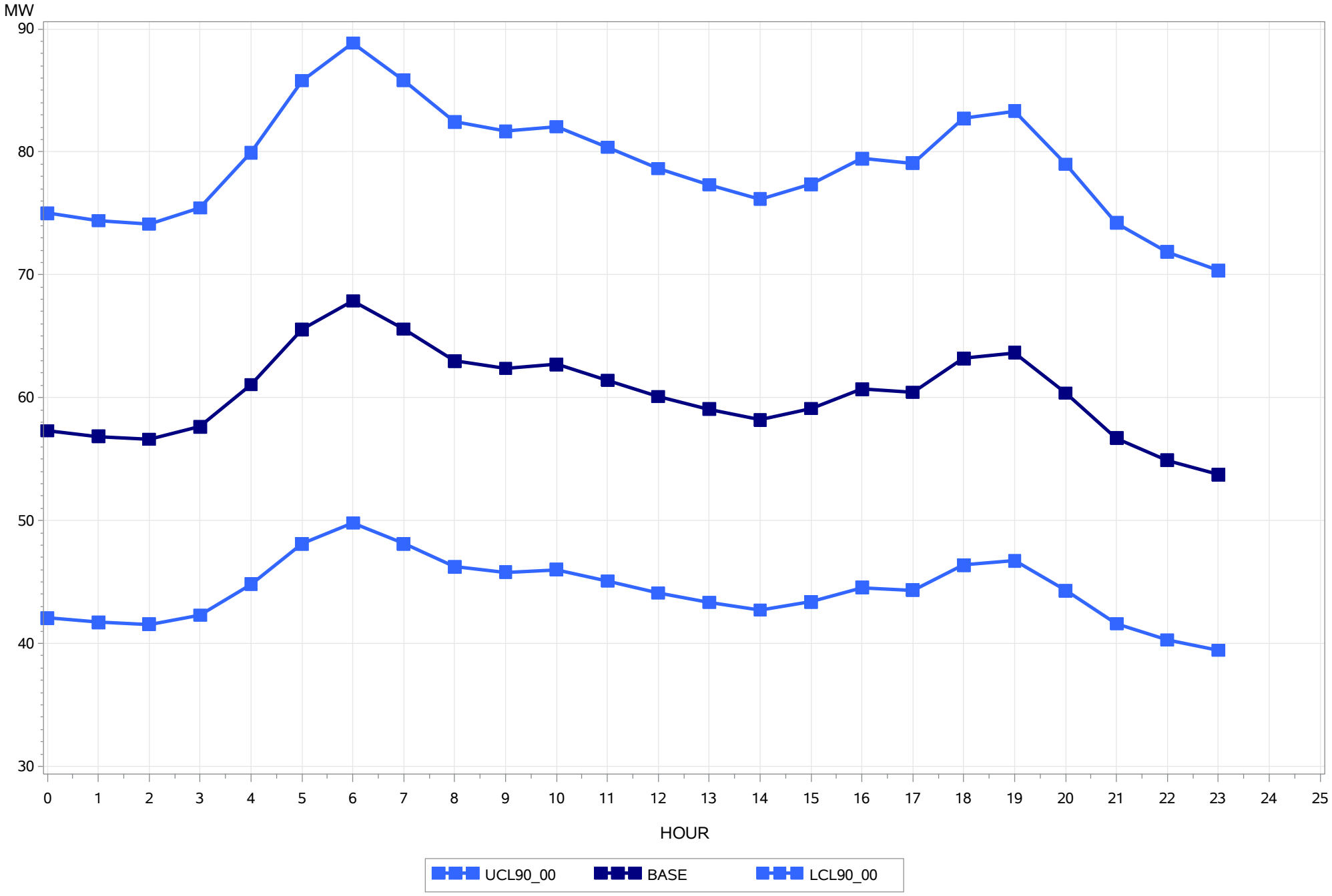
# Member Forecasted On Peak Demand Day for April 2021

**STATE OF NEBRASKA**

**Date of On Peak Day - 04/06/2021**



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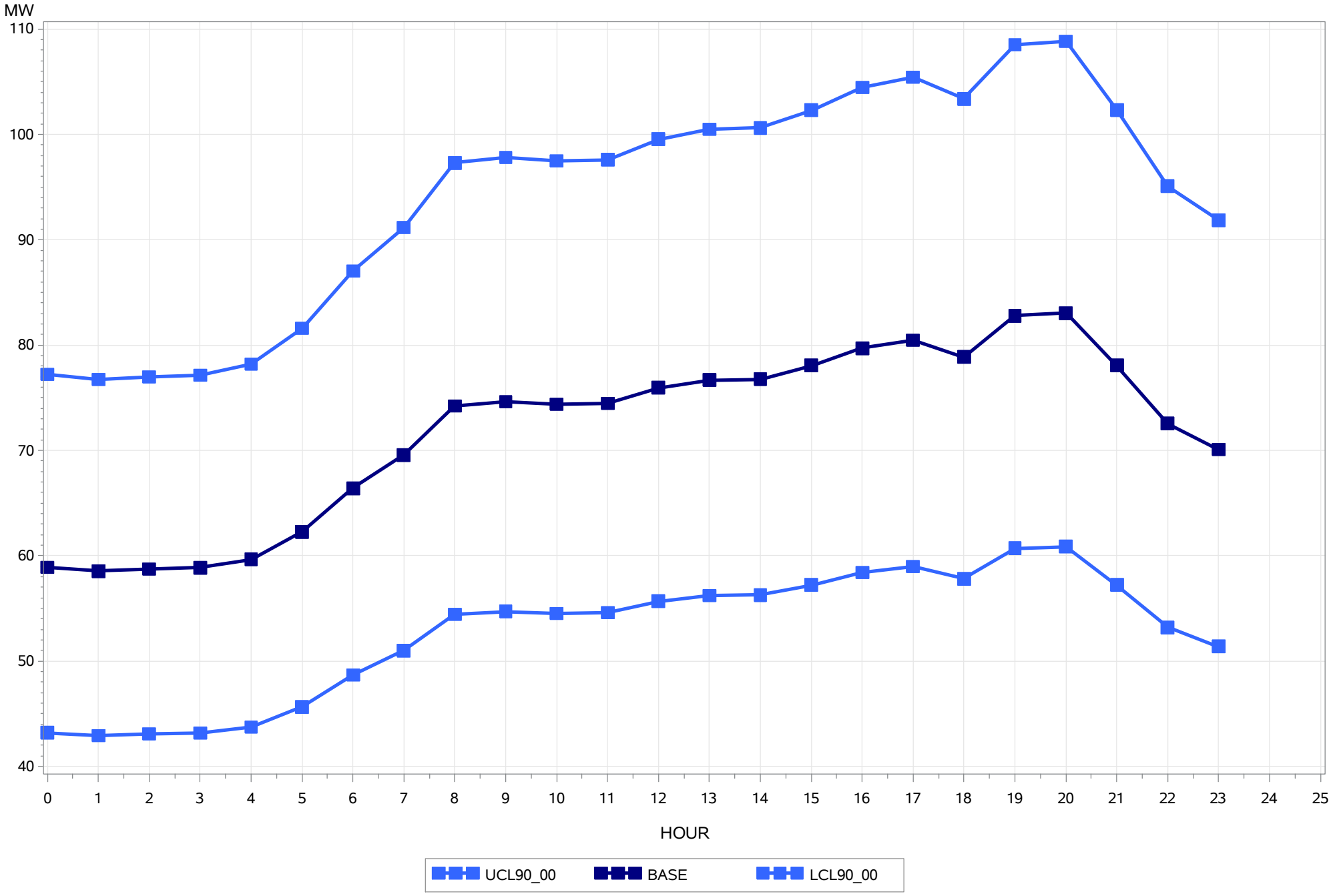
# Member Forecasted On Peak Demand Day for May 2021

**STATE OF NEBRASKA**

**Date of On Peak Day - 05/15/2021**



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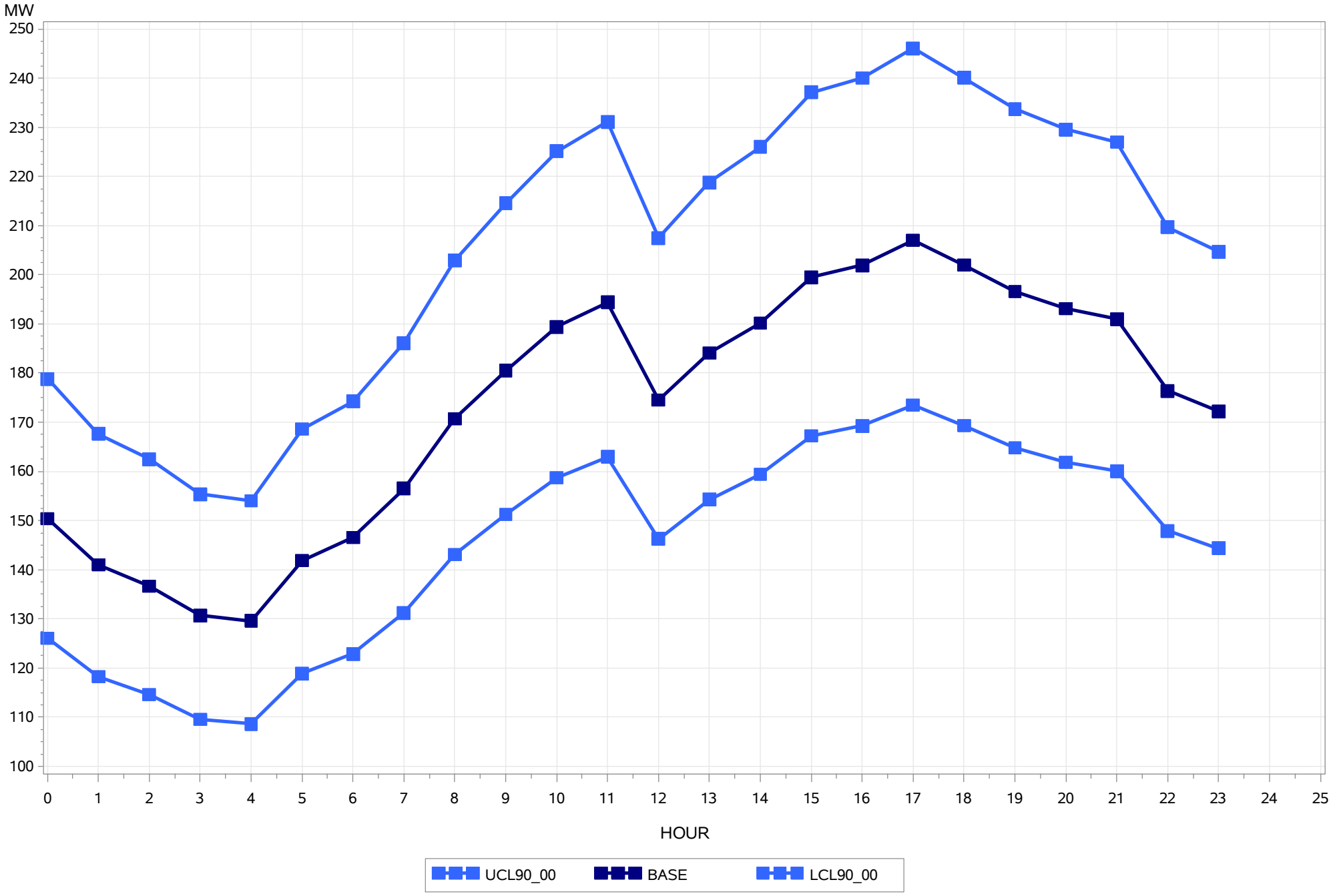
# Member Forecasted On Peak Demand Day for June 2021

**STATE OF NEBRASKA**

**Date of On Peak Day - 06/11/2021**



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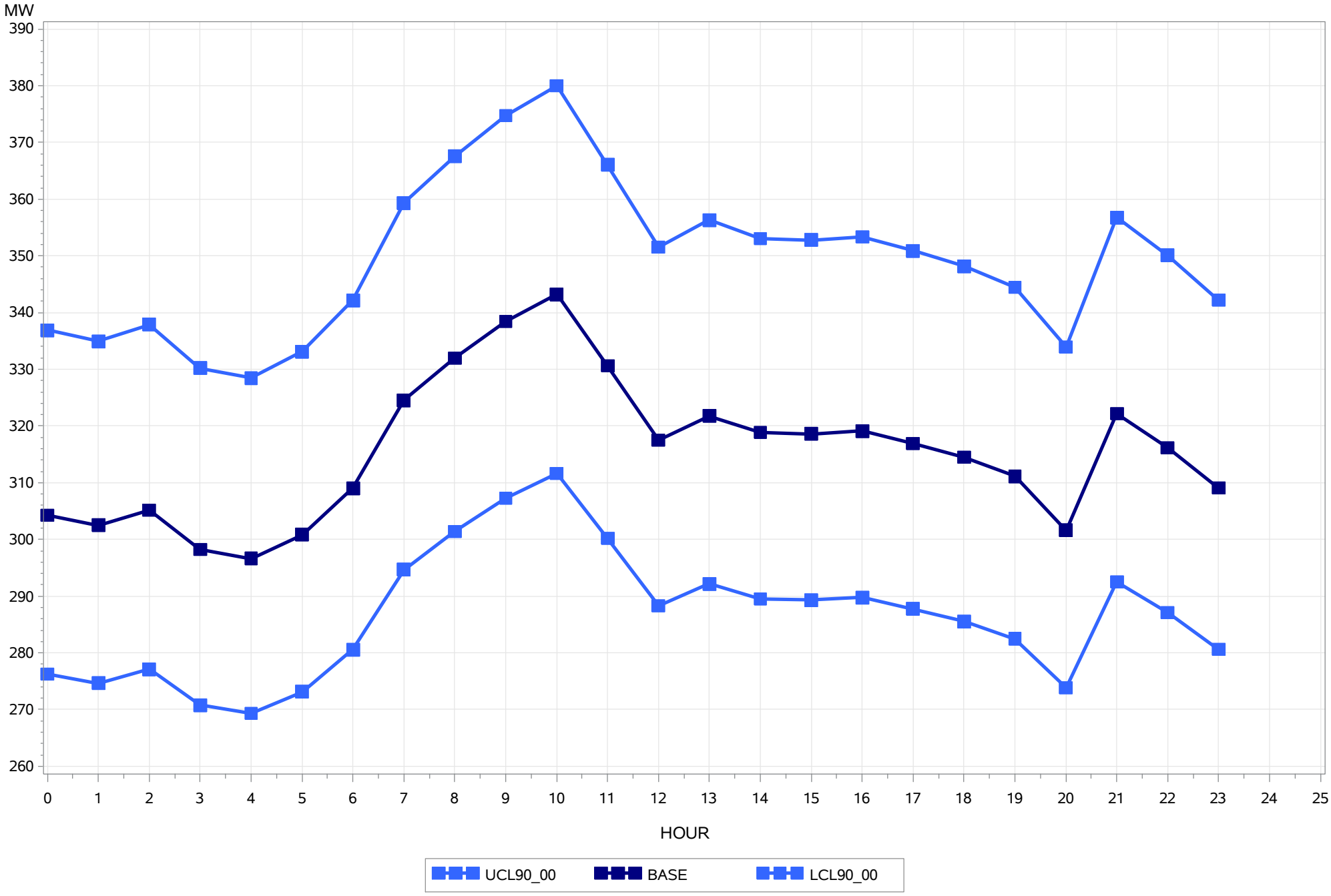
# Member Forecasted On Peak Demand Day for July 2021

**STATE OF NEBRASKA**

**Date of On Peak Day - 07/14/2021**



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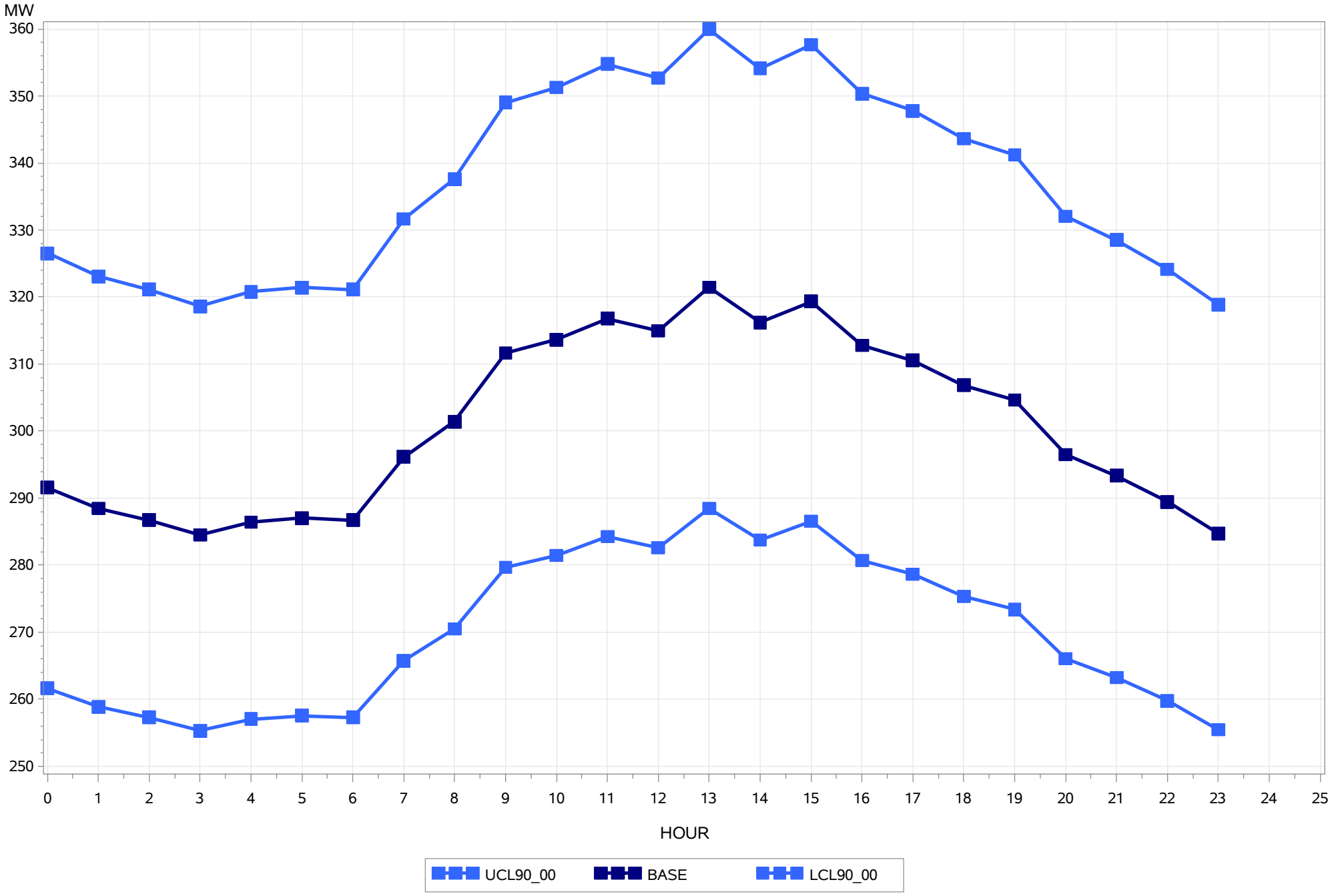
# Member Forecasted On Peak Demand Day for August 2021

**STATE OF NEBRASKA**

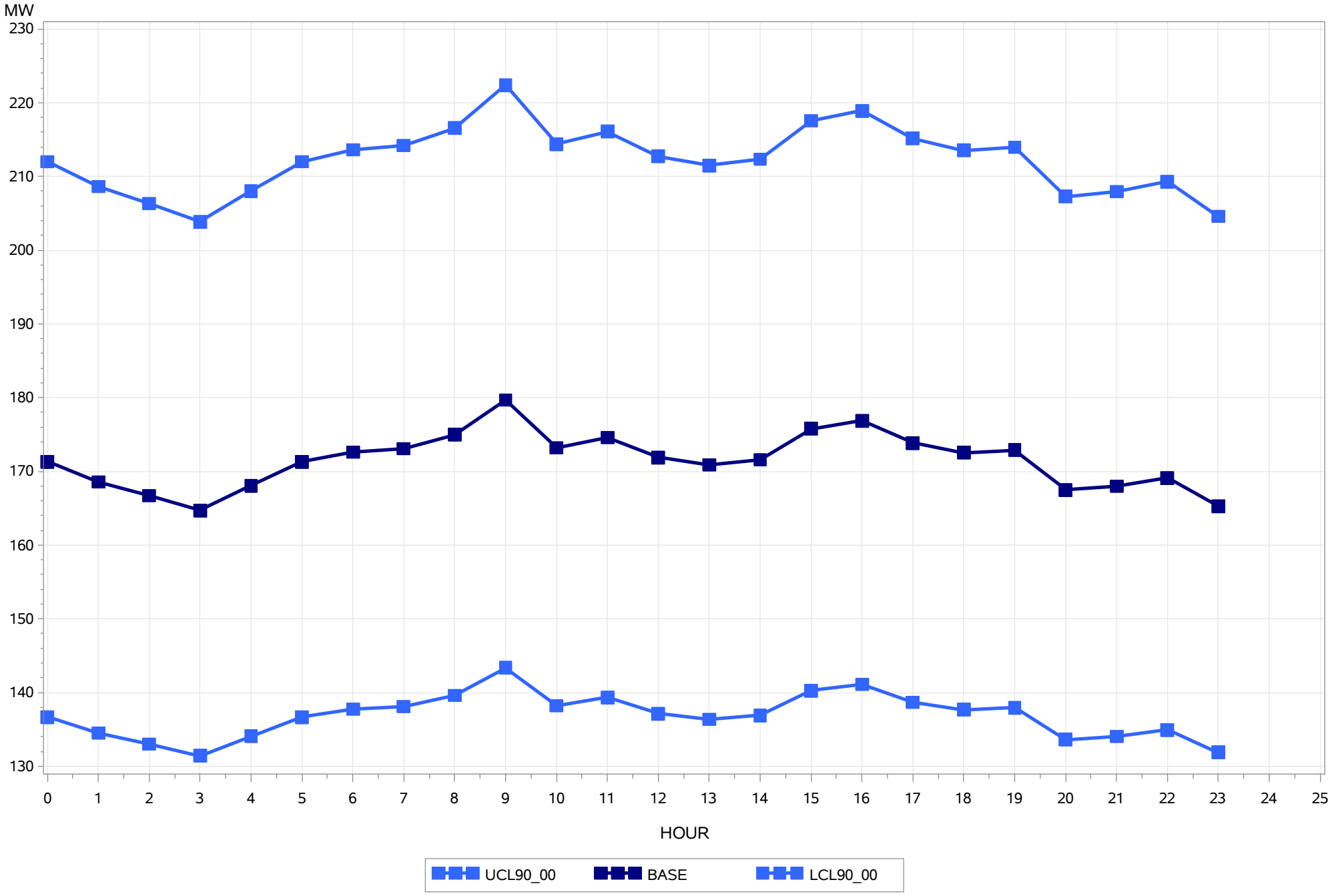
**Date of On Peak Day - 08/24/2021**



# Member Forecasted On Peak Demand Day for September 2021

**STATE OF NEBRASKA**

**Date of On Peak Day - 09/01/2021**



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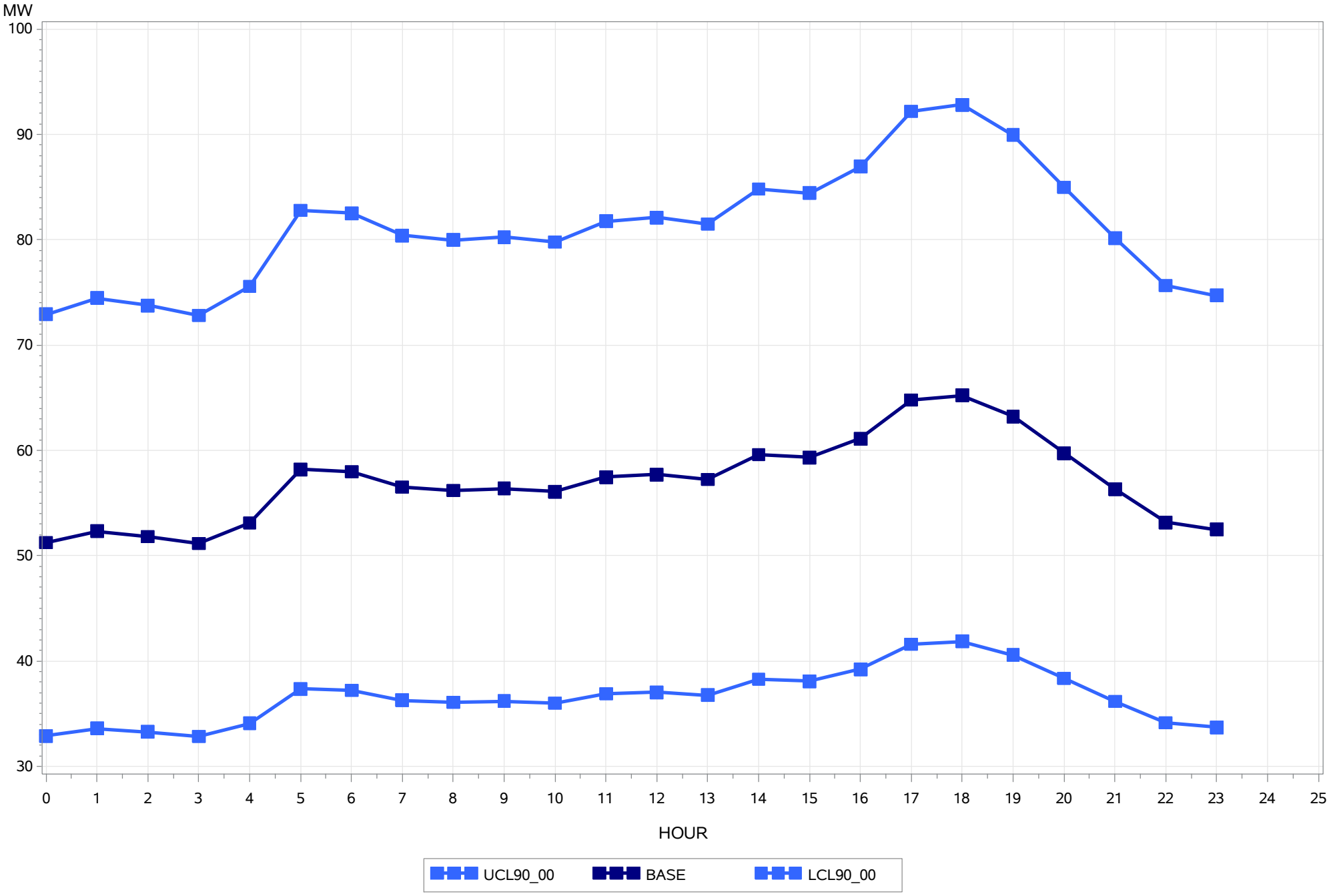
# Member Forecasted On Peak Demand Day for October 2021

**STATE OF NEBRASKA**

**Date of On Peak Day - 10/13/2021**



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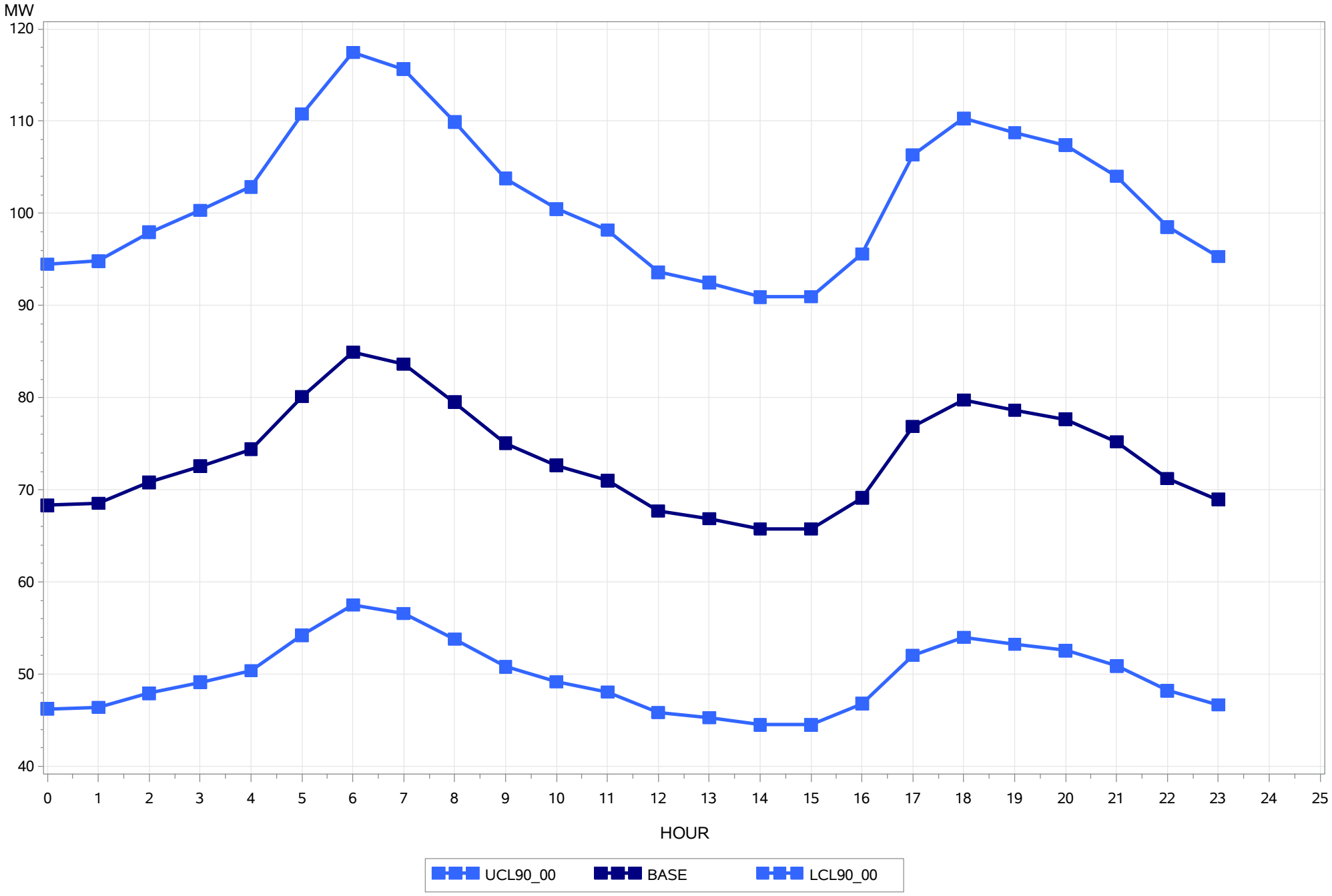
# Member Forecasted On Peak Demand Day for November 2021

**STATE OF NEBRASKA**

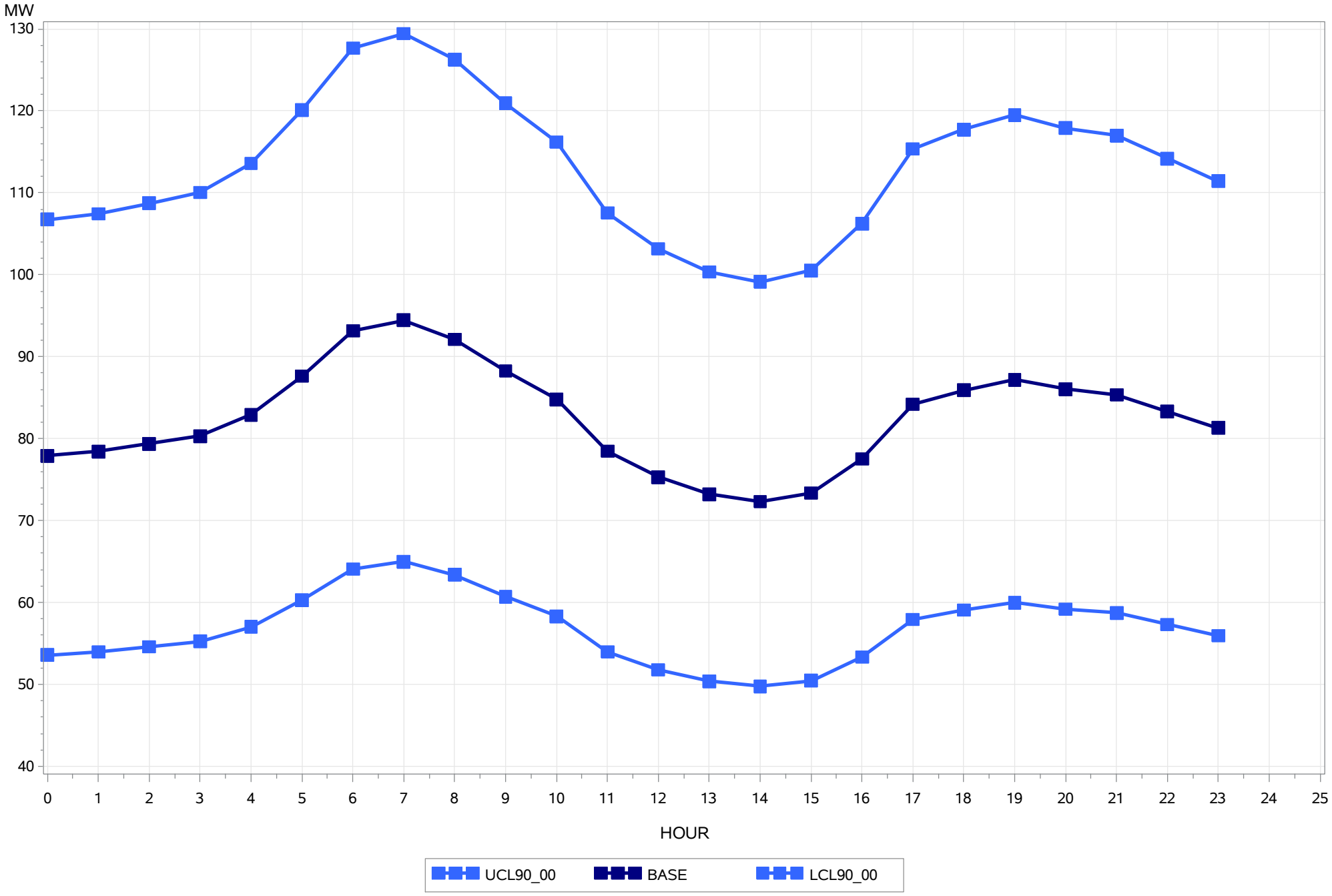
**Date of On Peak Day - 11/09/2021**



# Member Forecasted On Peak Demand Day for December 2021

**STATE OF NEBRASKA**

**Date of On Peak Day - 12/30/2021**



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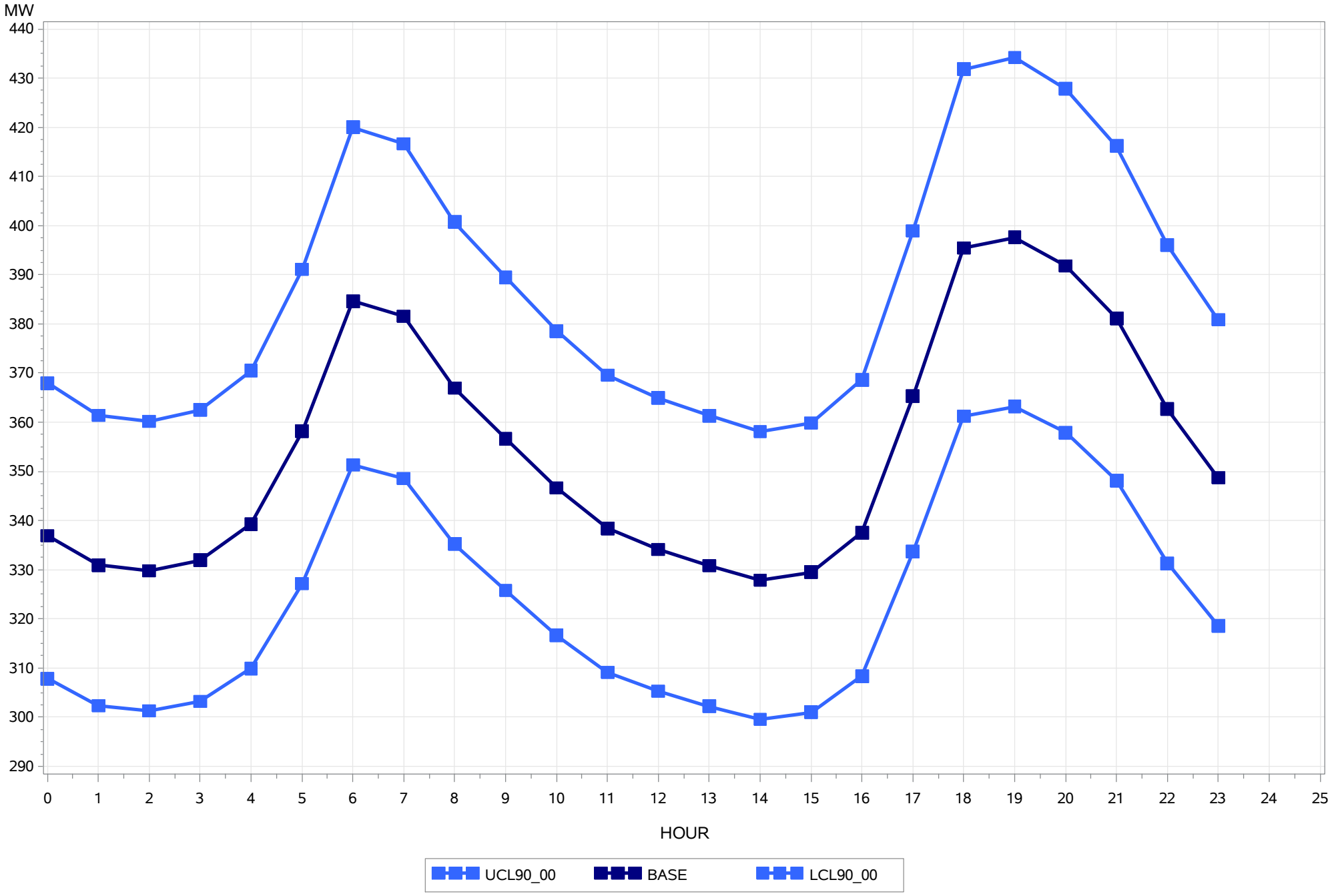
# Member Forecasted On Peak Demand Day for January 2021

**STATE OF NEW MEXICO**

**Date of On Peak Day - 01/26/2021**



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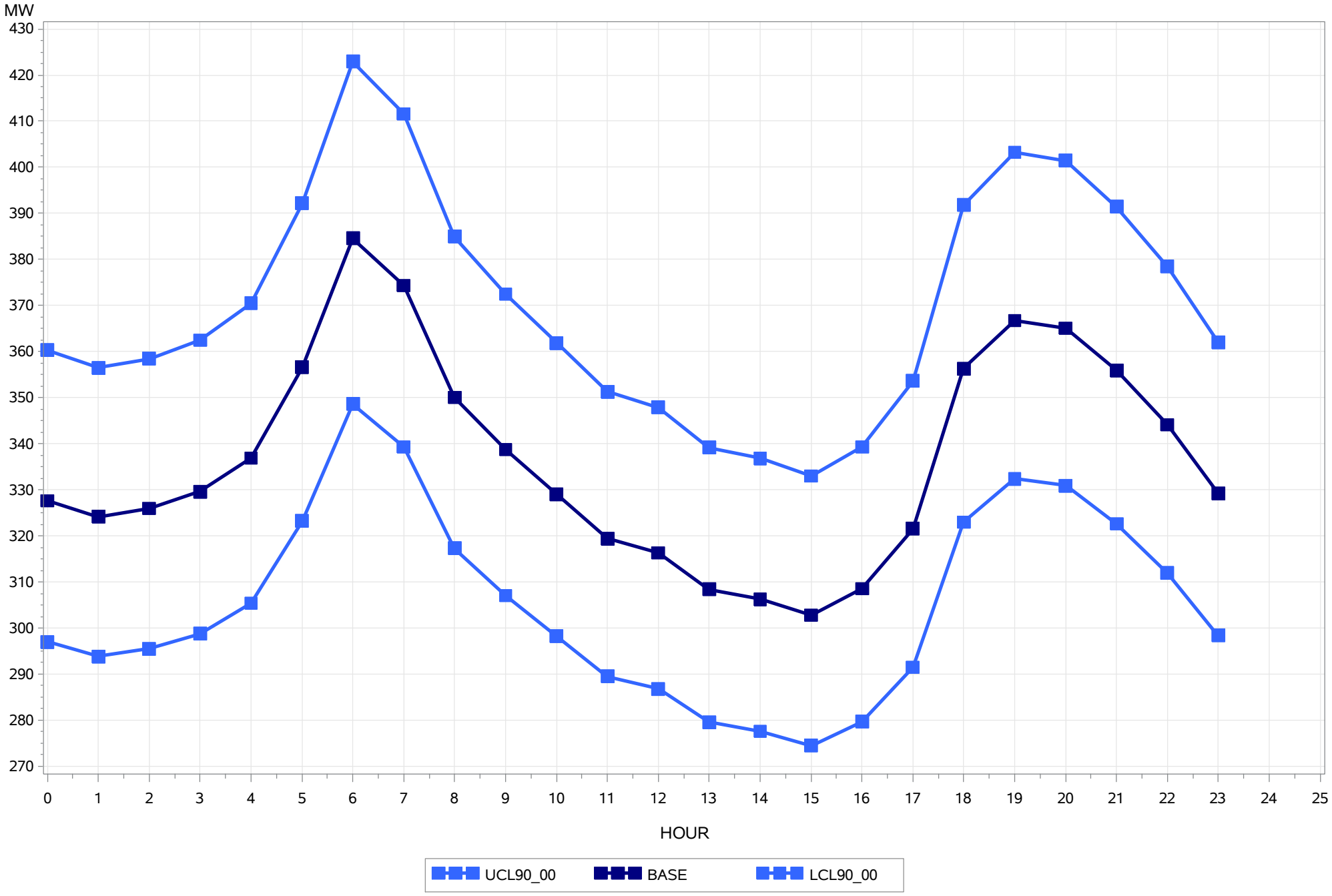
**STATE OF NEW MEXICO**

**Date of On Peak Day - 02/25/2021**



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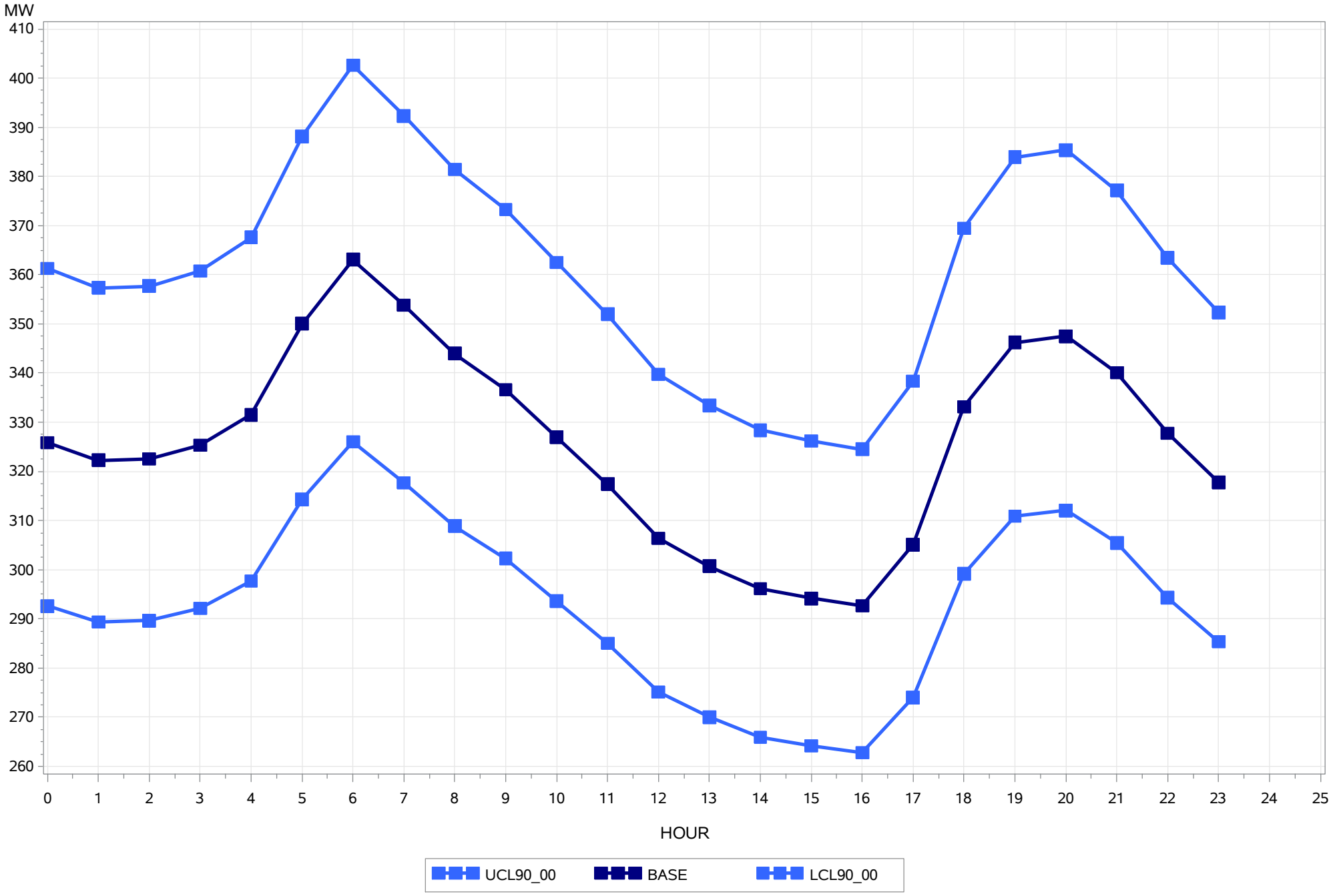
**STATE OF NEW MEXICO**

**Date of On Peak Day - 03/02/2021**



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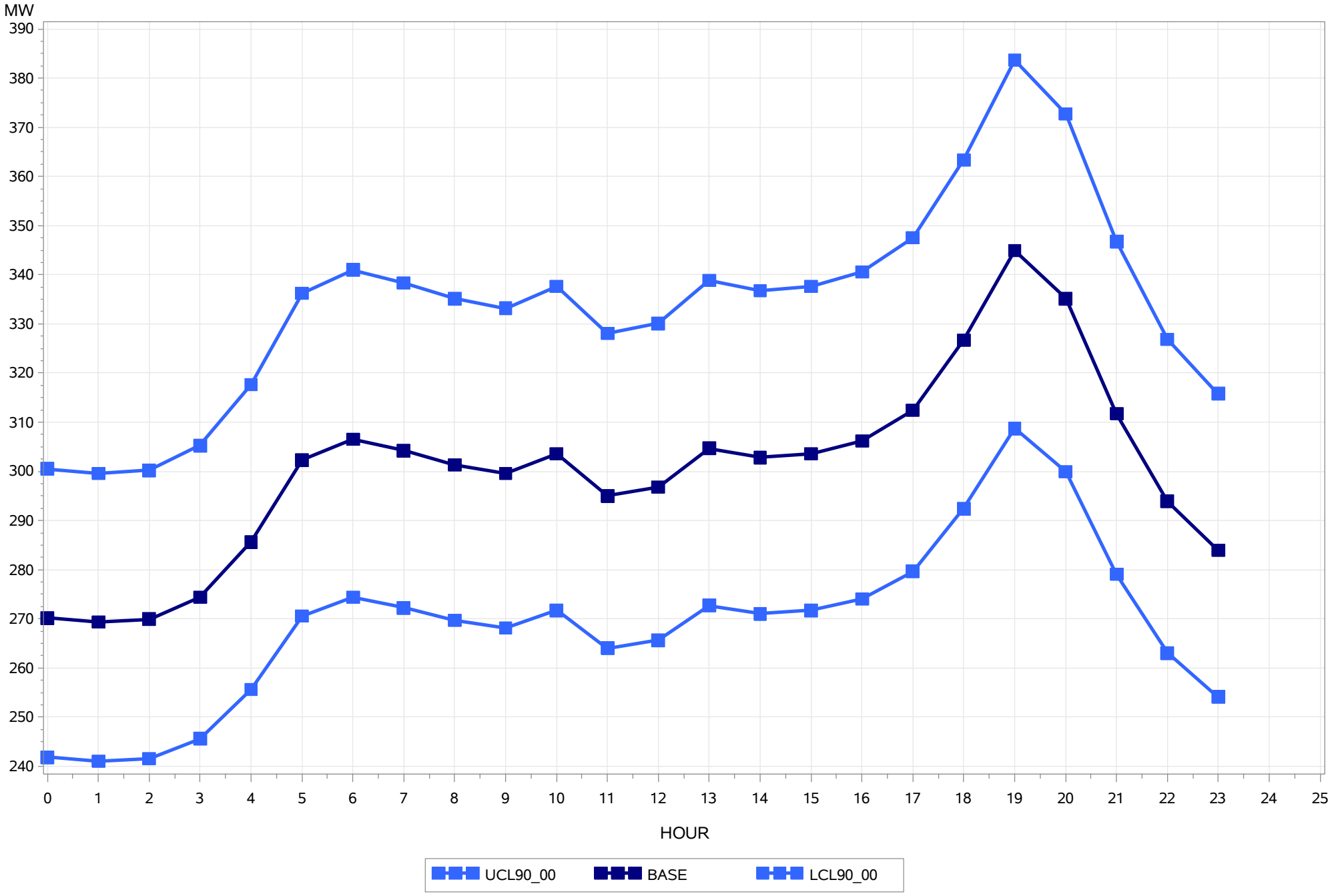
# Member Forecasted On Peak Demand Day for April 2021

**STATE OF NEW MEXICO**

**Date of On Peak Day - 04/12/2021**



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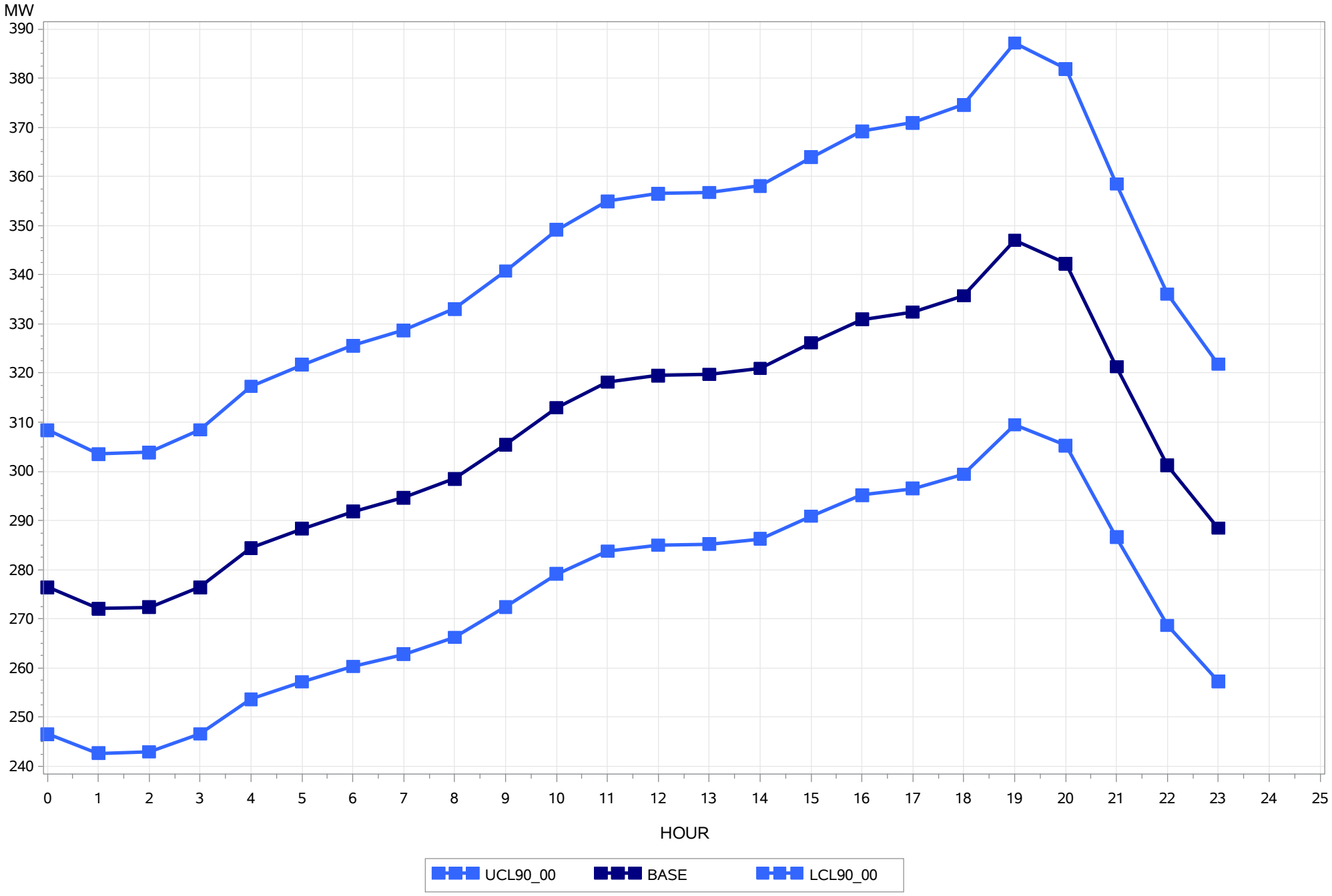
# Member Forecasted On Peak Demand Day for May 2021

**STATE OF NEW MEXICO**

**Date of On Peak Day - 05/26/2021**



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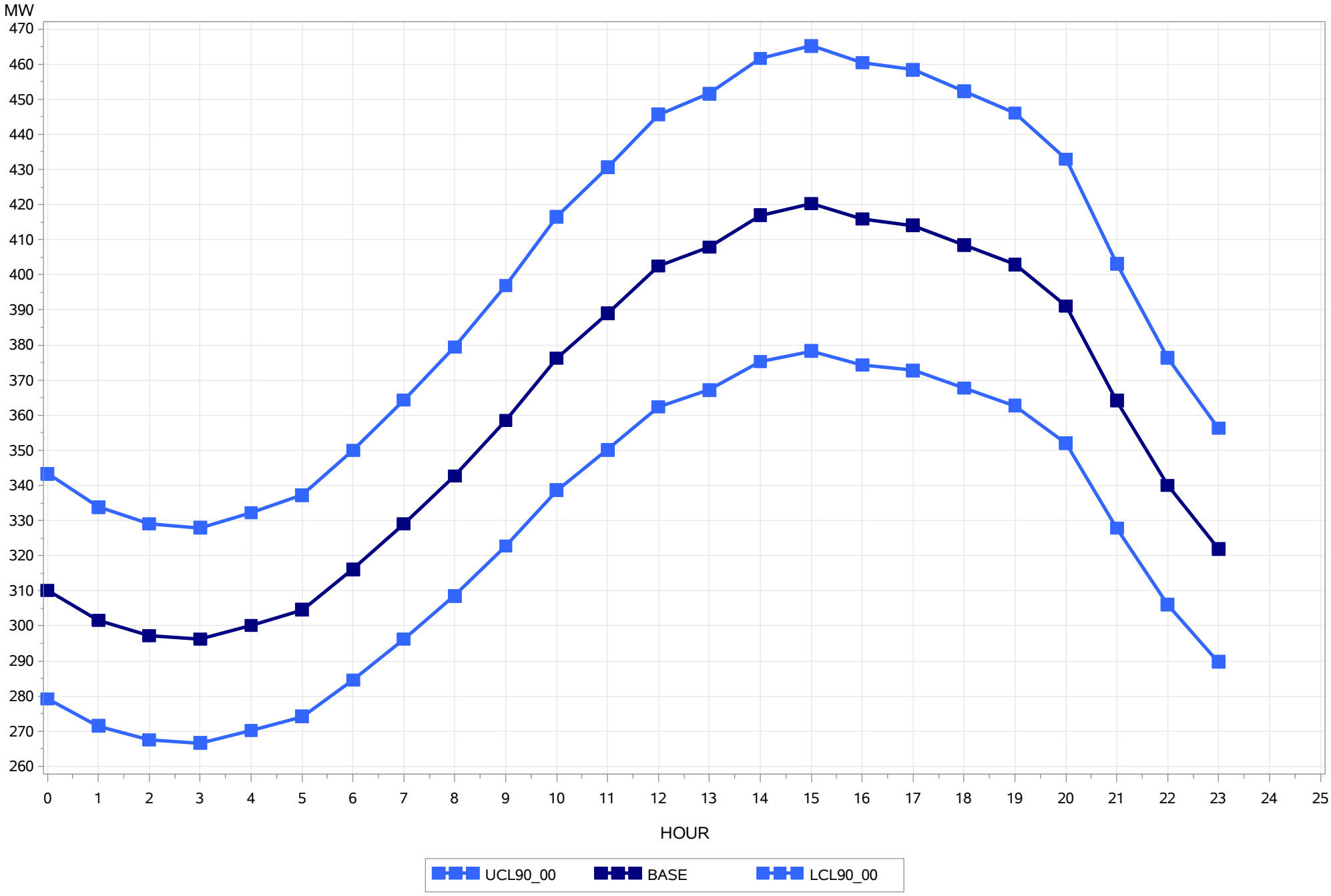
# Member Forecasted On Peak Demand Day for June 2021

**STATE OF NEW MEXICO**

**Date of On Peak Day - 06/24/2021**



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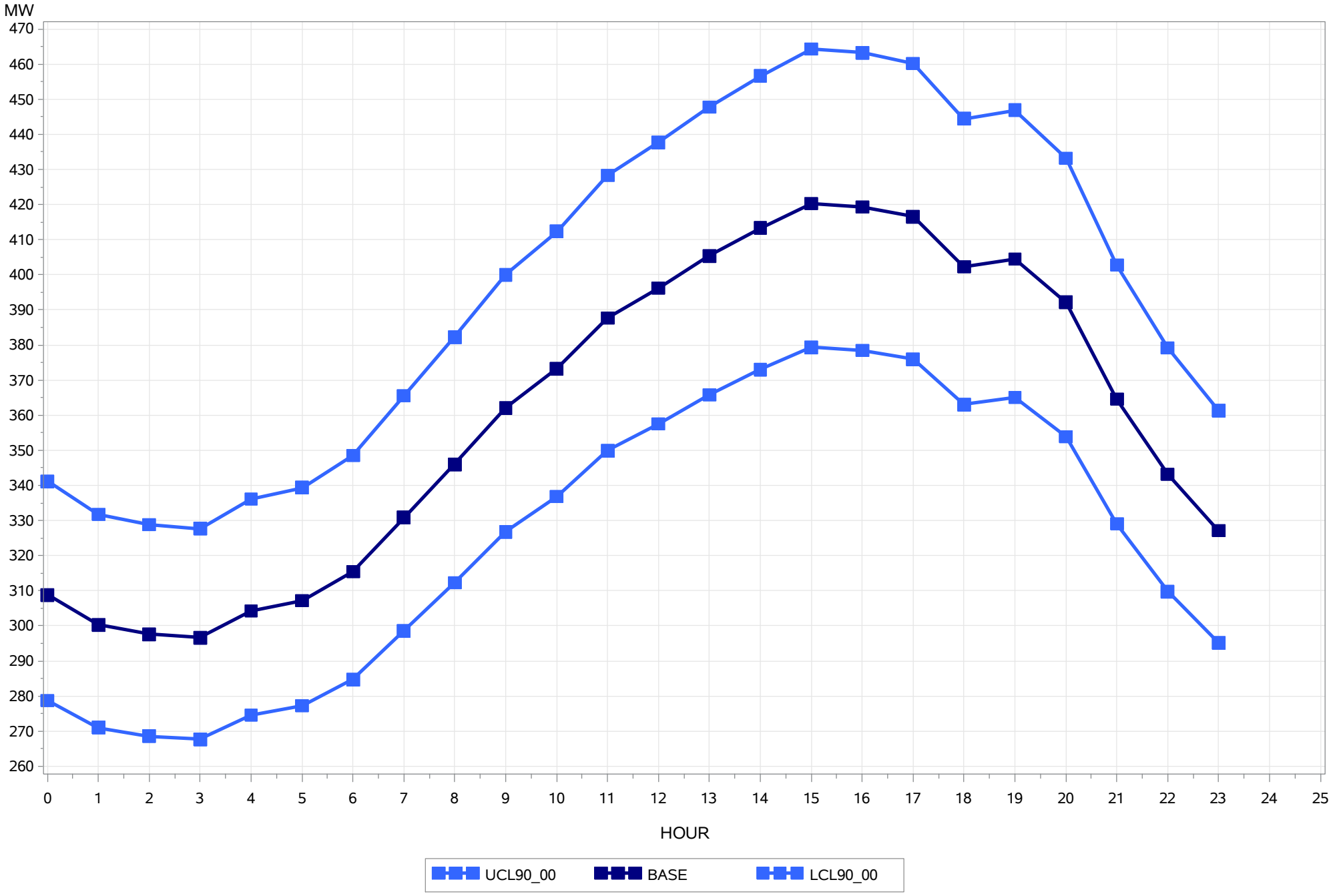
# Member Forecasted On Peak Demand Day for July 2021

**STATE OF NEW MEXICO**

**Date of On Peak Day - 07/22/2021**



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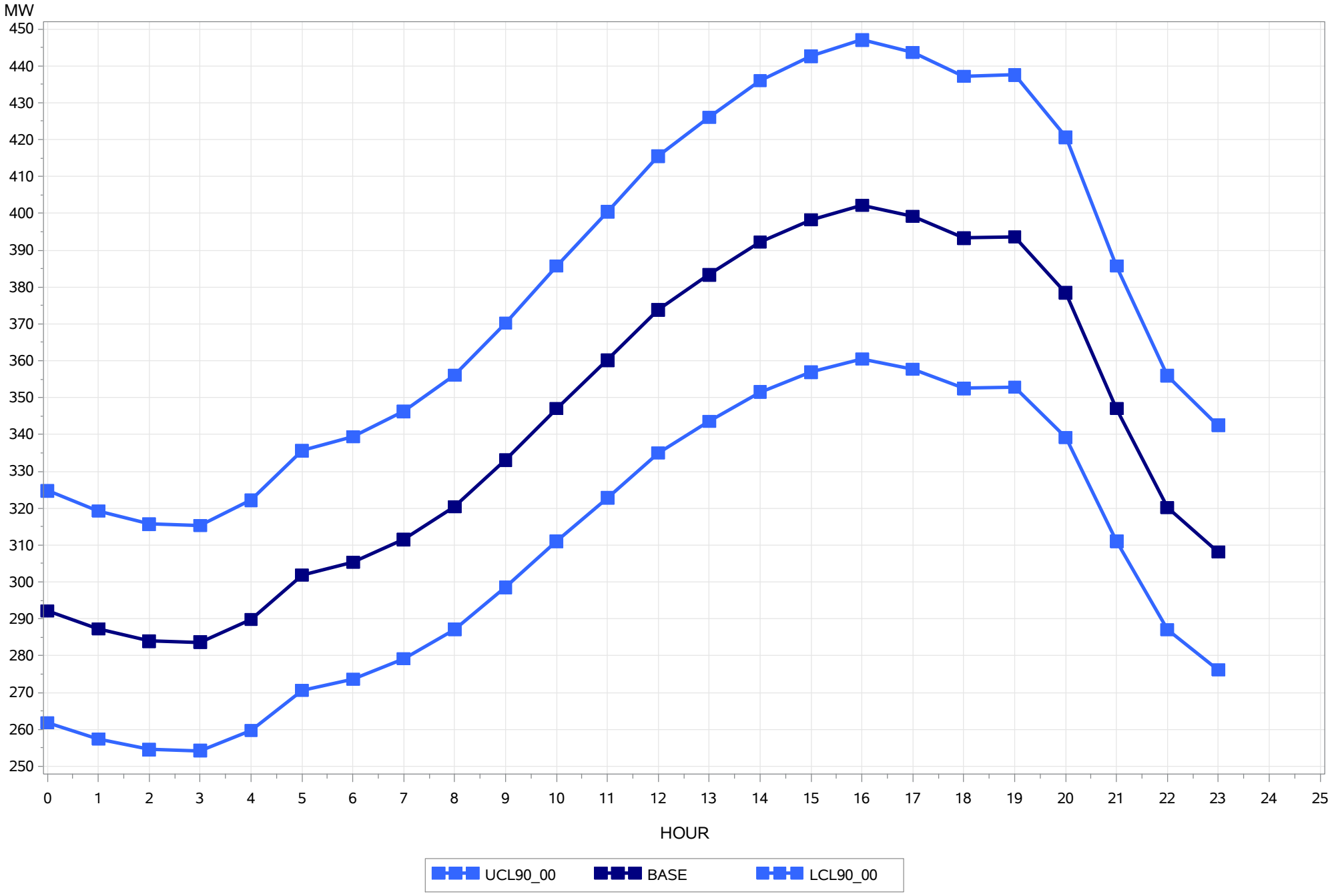
# Member Forecasted On Peak Demand Day for August 2021

**STATE OF NEW MEXICO**

**Date of On Peak Day - 08/18/2021**



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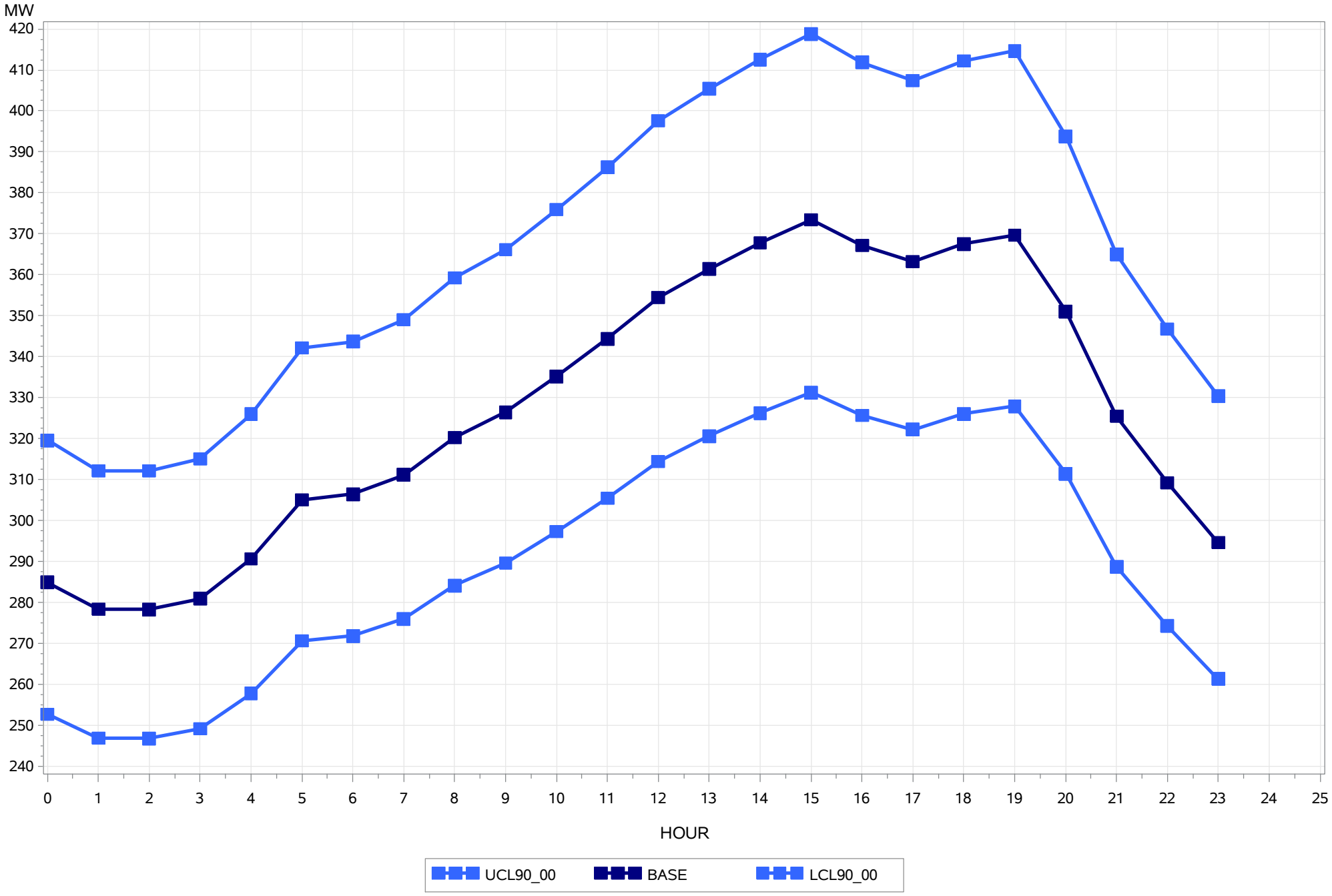

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# Member Forecasted On Peak Demand Day for October 2021

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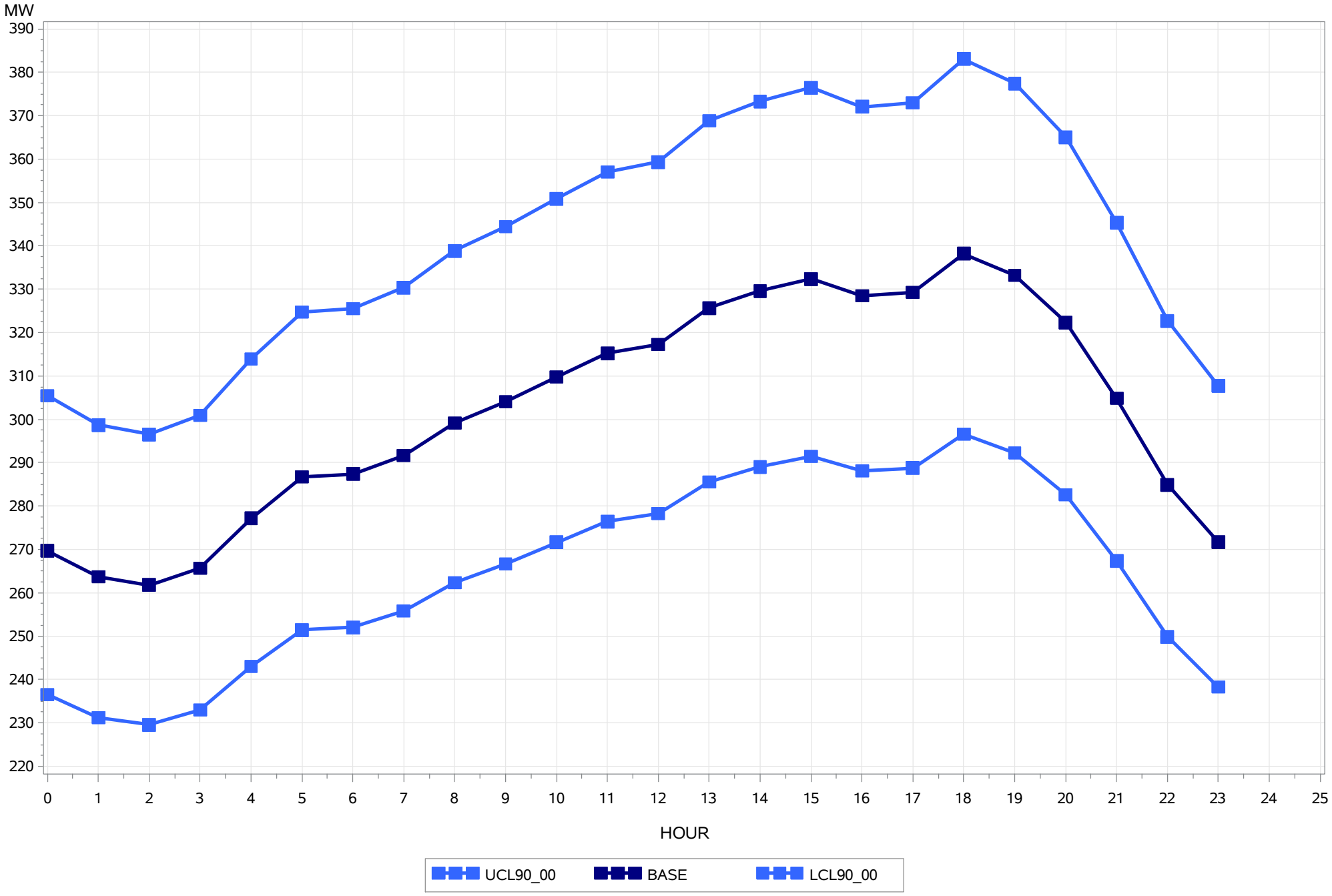
**Date of On Peak Day - 10/01/2021**



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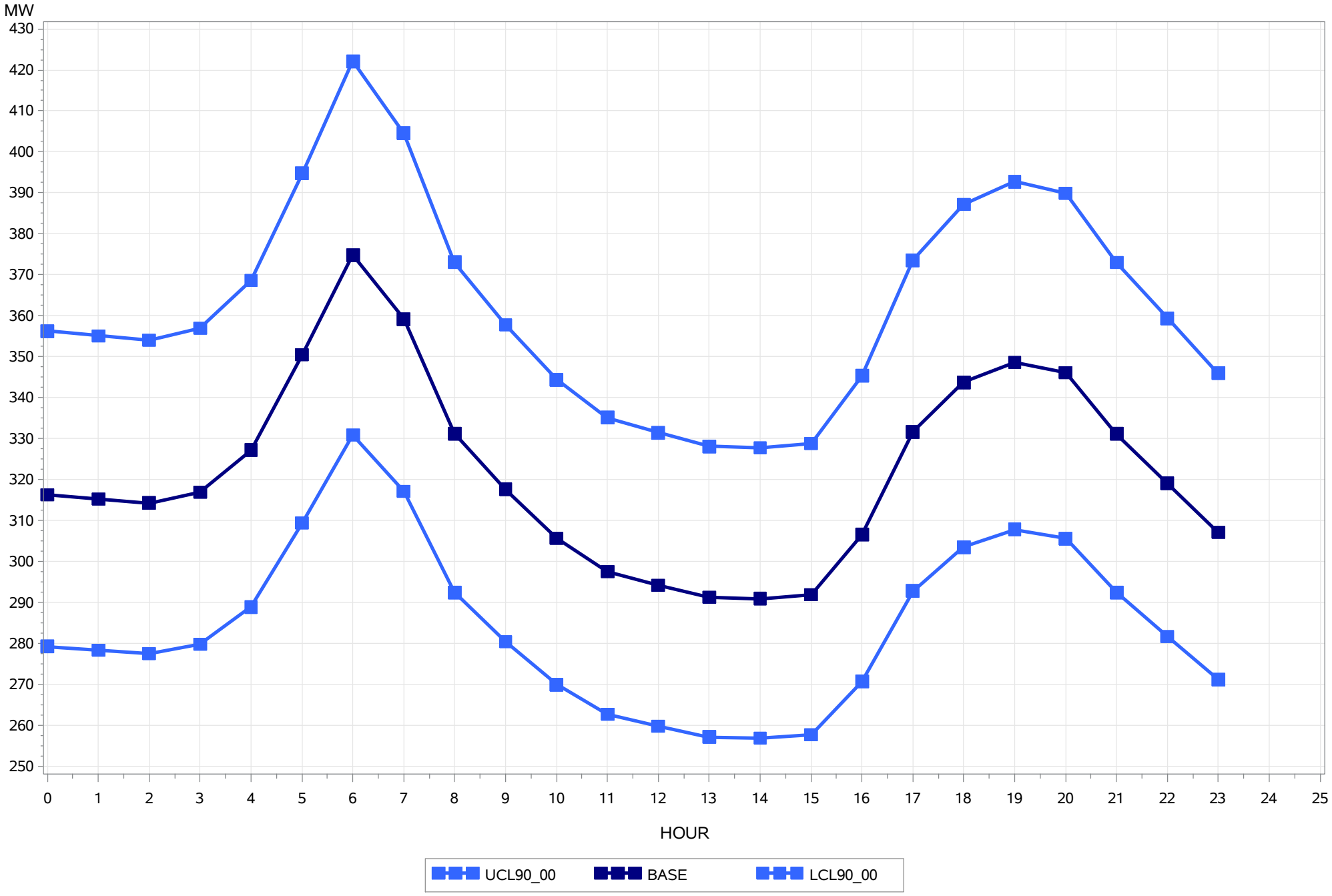
# Member Forecasted On Peak Demand Day for November 2021

**STATE OF NEW MEXICO**

**Date of On Peak Day - 11/16/2021**



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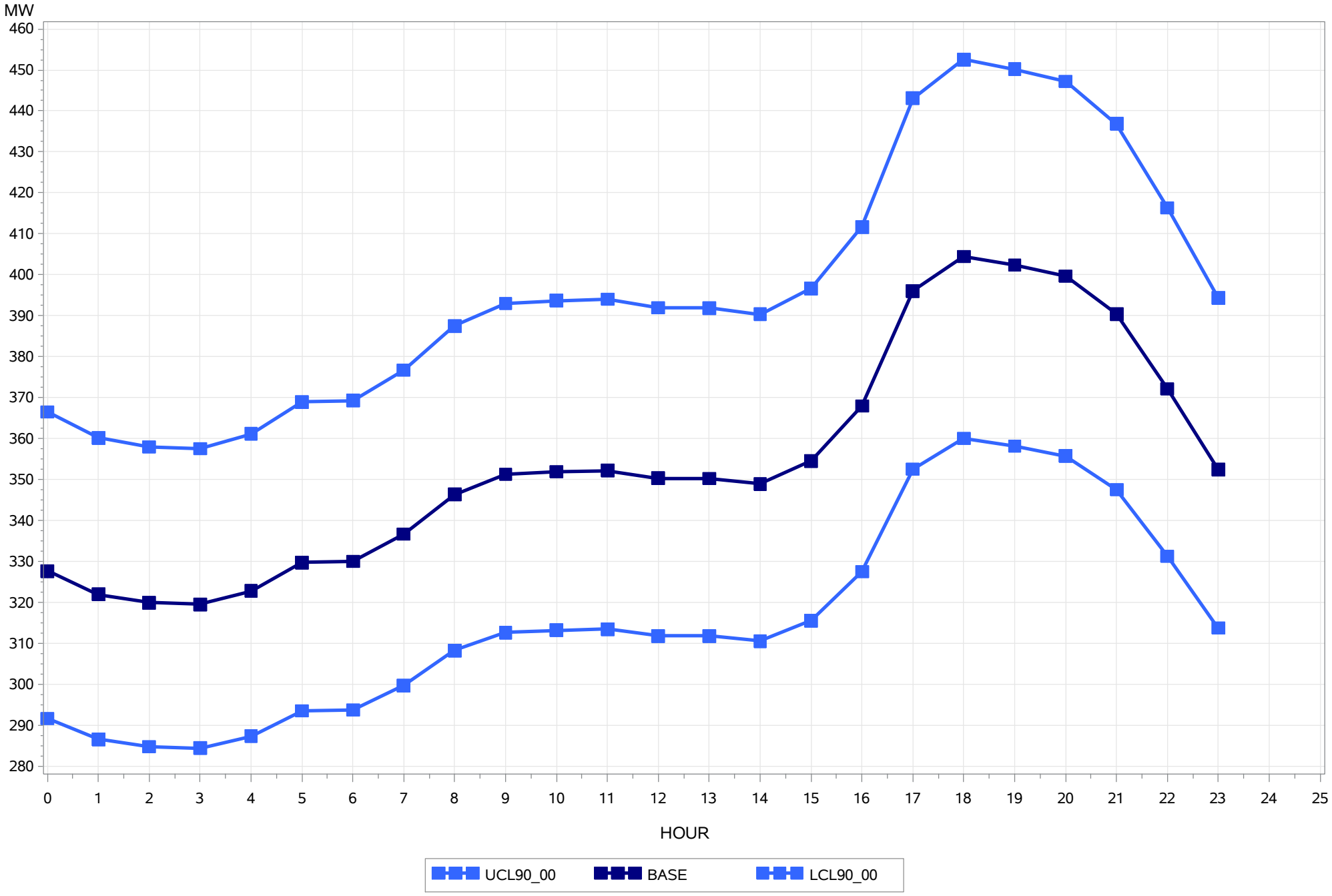
**STATE OF NEW MEXICO**

**Date of On Peak Day - 12/26/2021**



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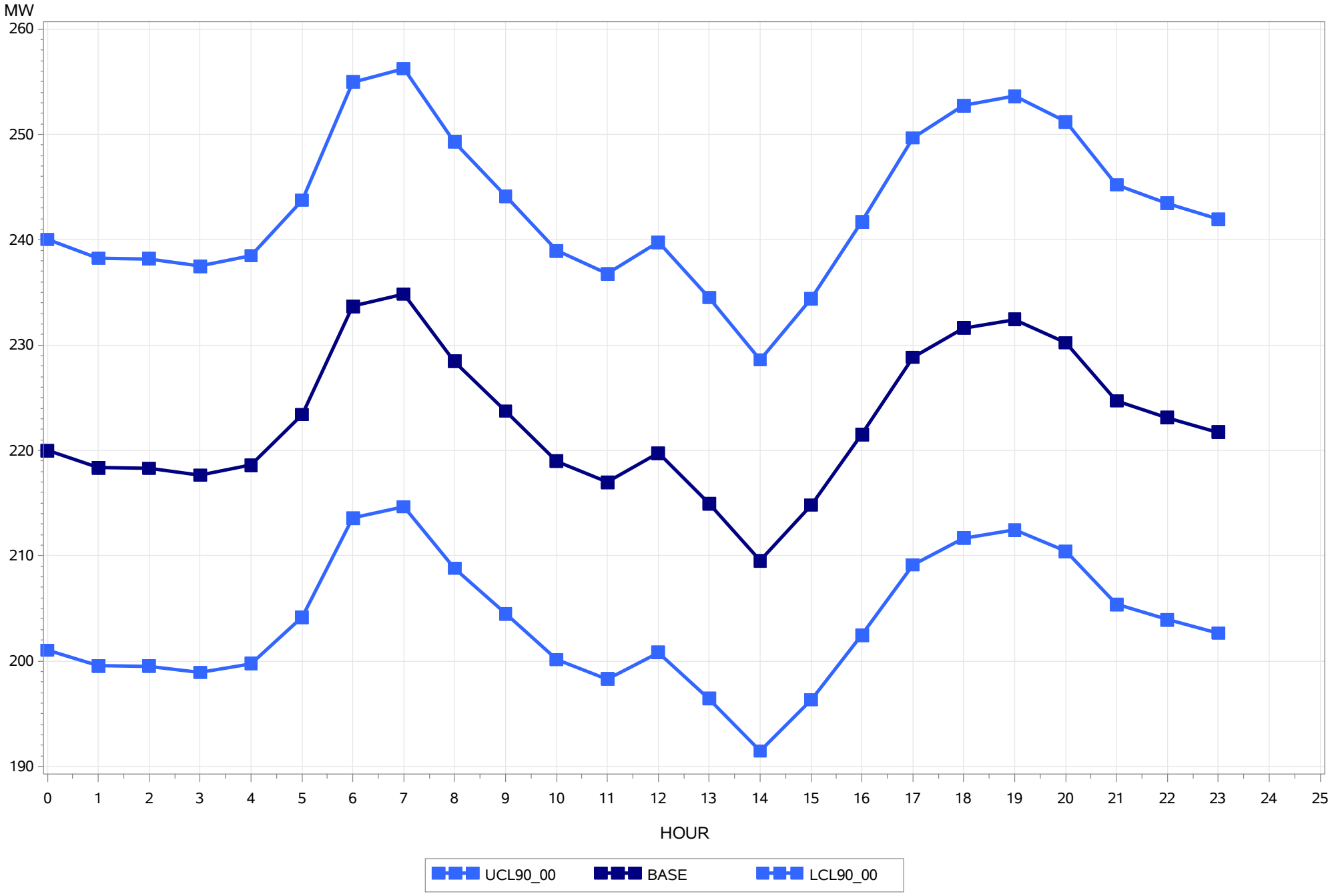
# Member Forecasted On Peak Demand Day for January 2021

**STATE OF WYOMING**

**Date of On Peak Day - 01/07/2021**



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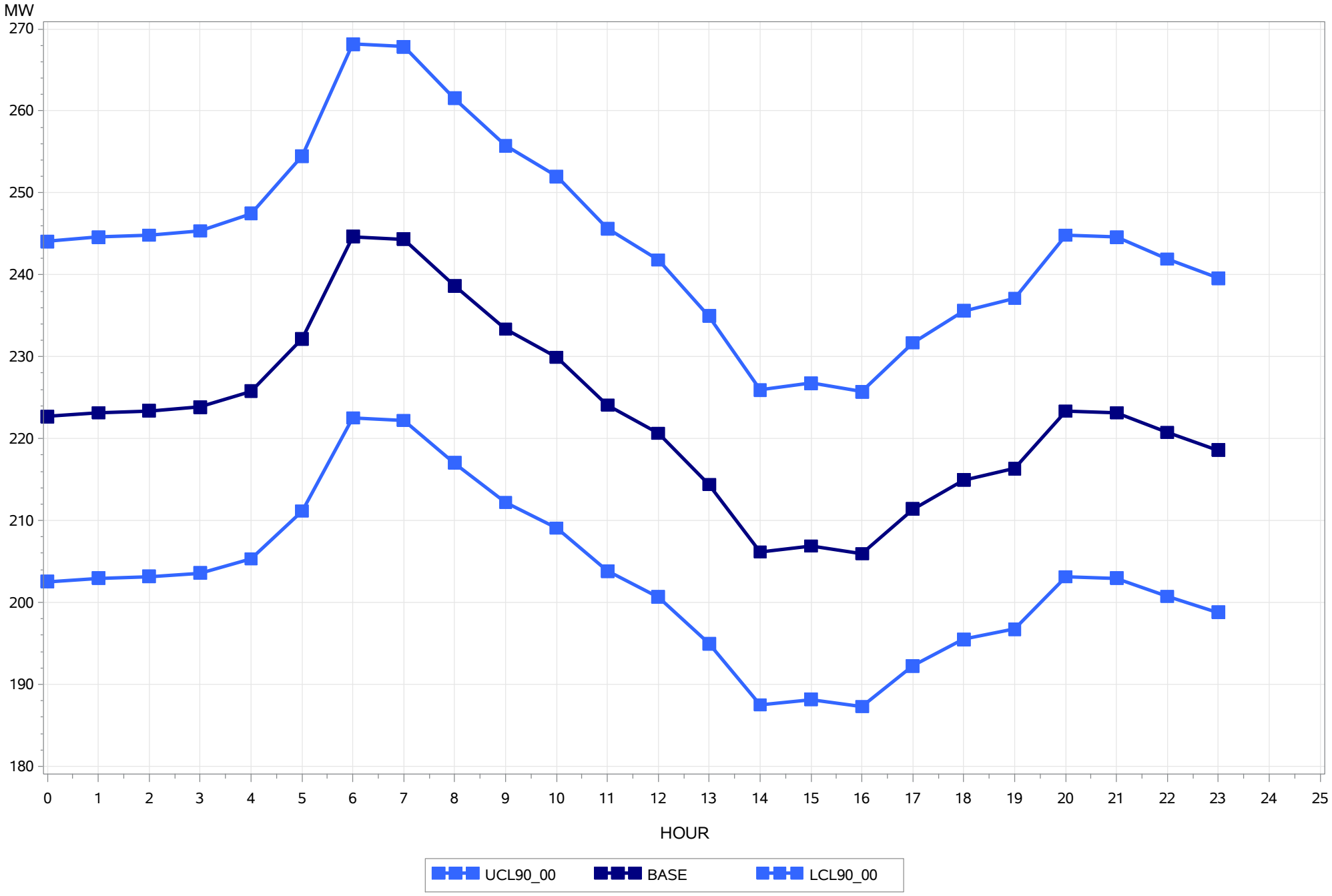
**Date of On Peak Day - 02/03/2021**



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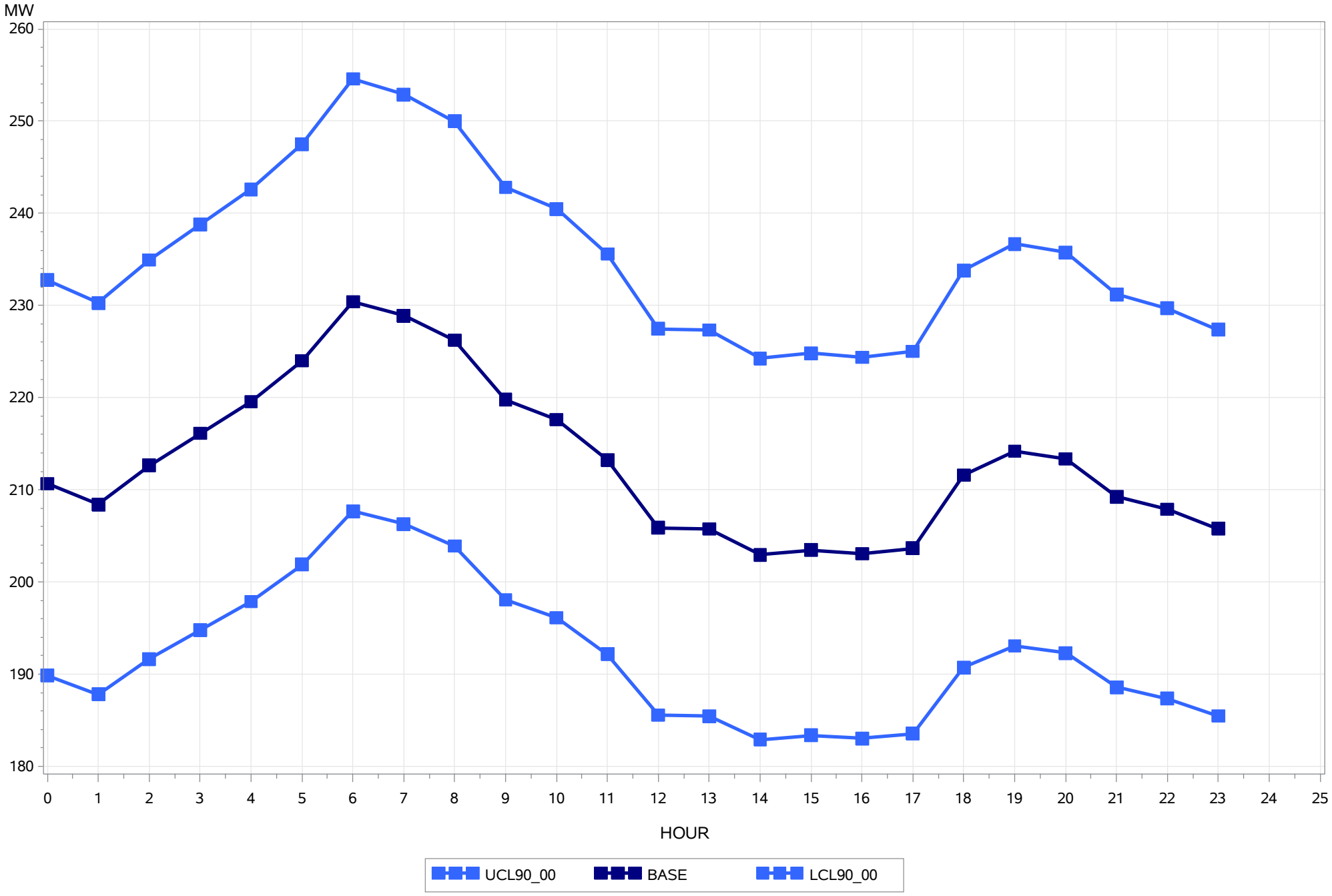
## STATE OF WYOMING

## Date of On Peak Day - 03/02/2021



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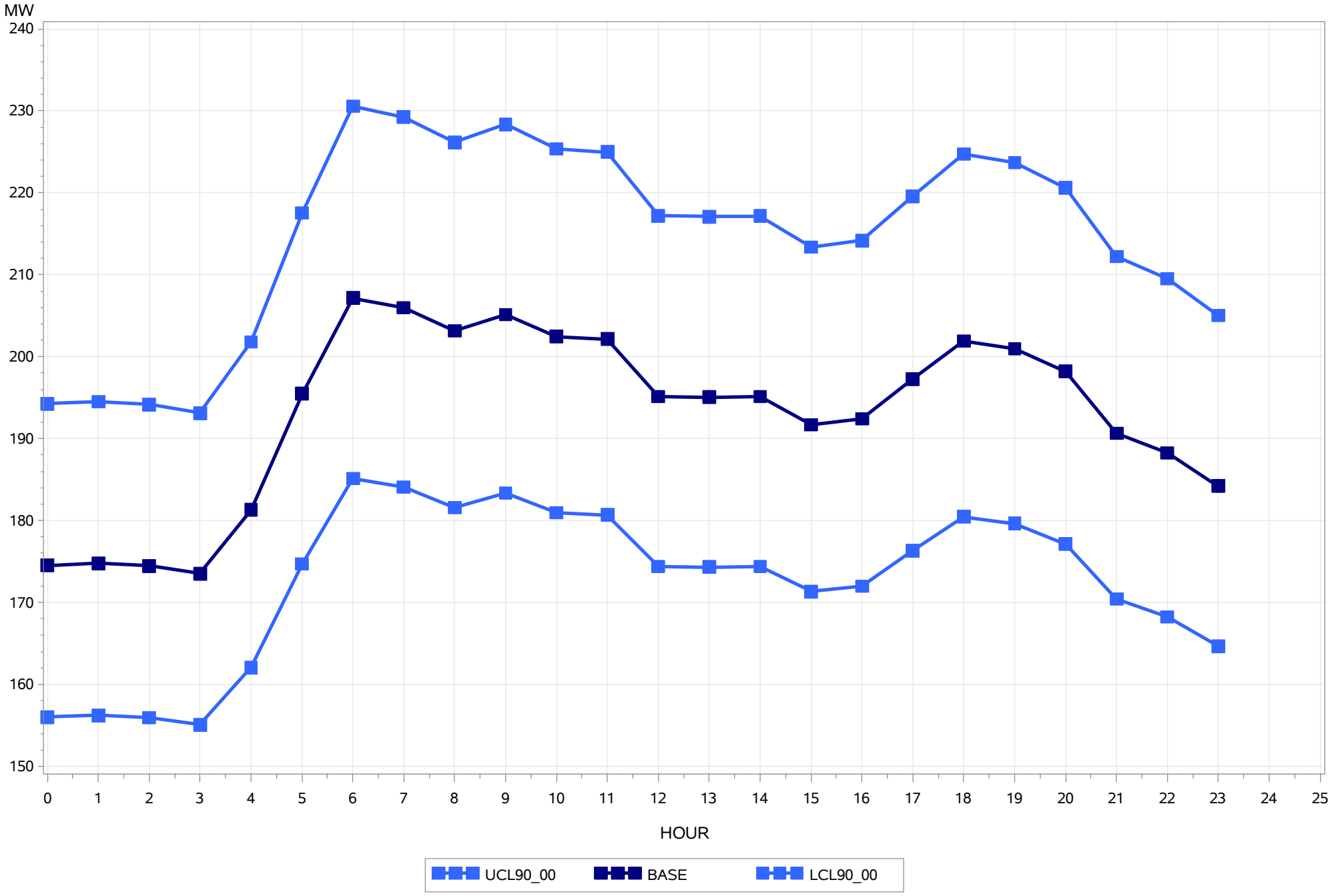

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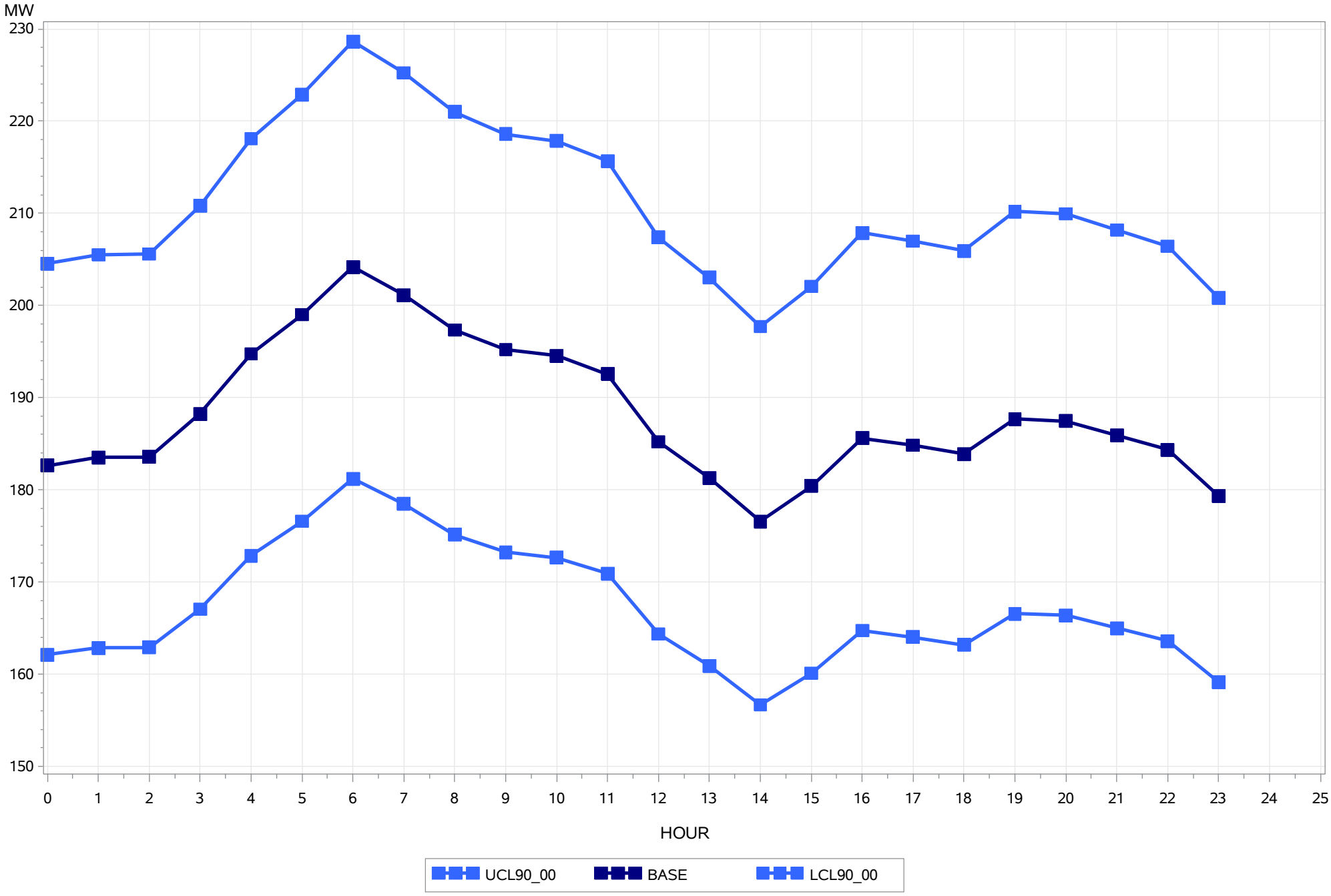

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# Member Forecasted On Peak Demand Day for June 2021

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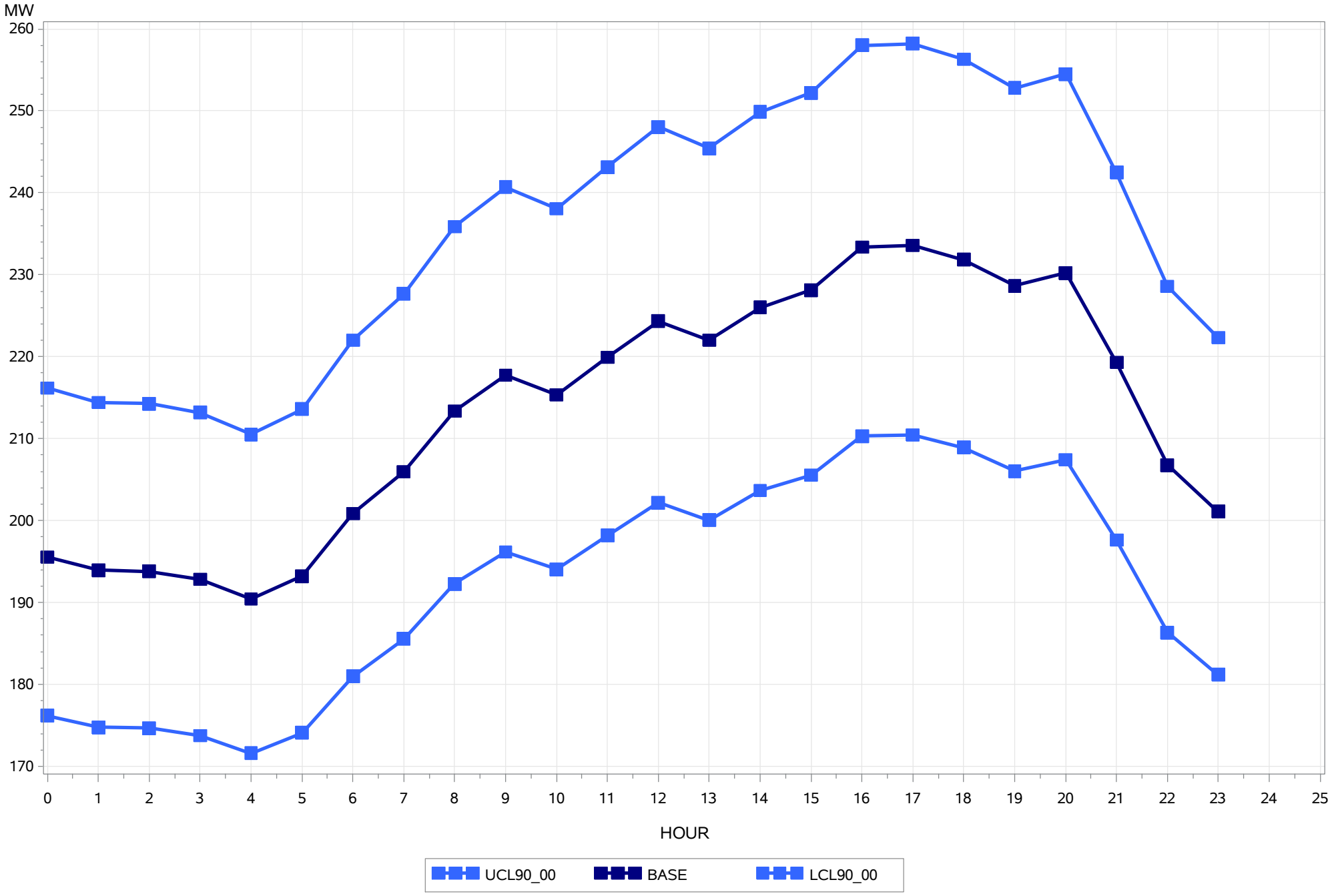

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# Member Forecasted On Peak Demand Day for July 2021

## STATE OF WYOMING

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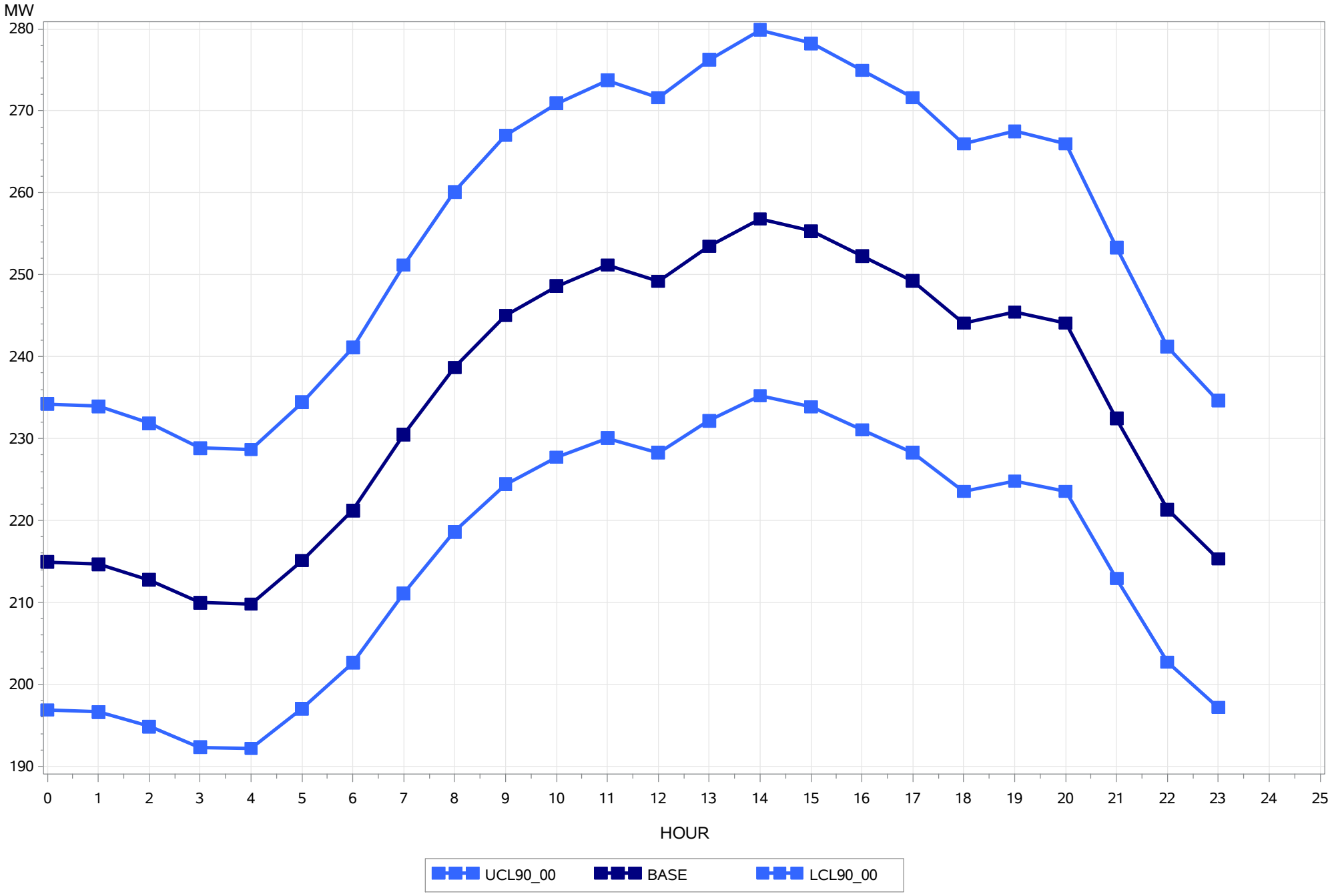

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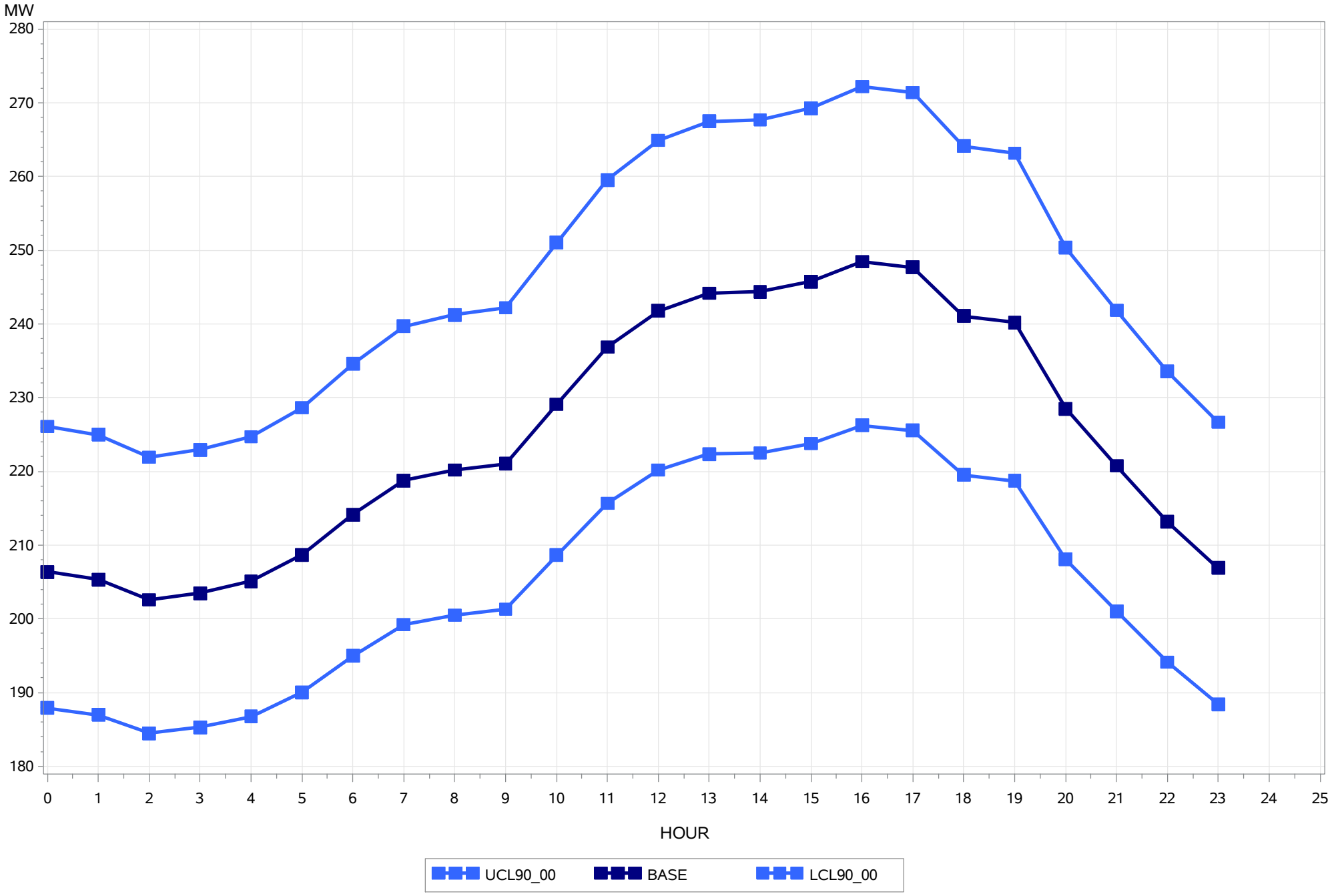
# Member Forecasted On Peak Demand Day for August 2021

**STATE OF WYOMING**

**Date of On Peak Day - 08/28/2021**



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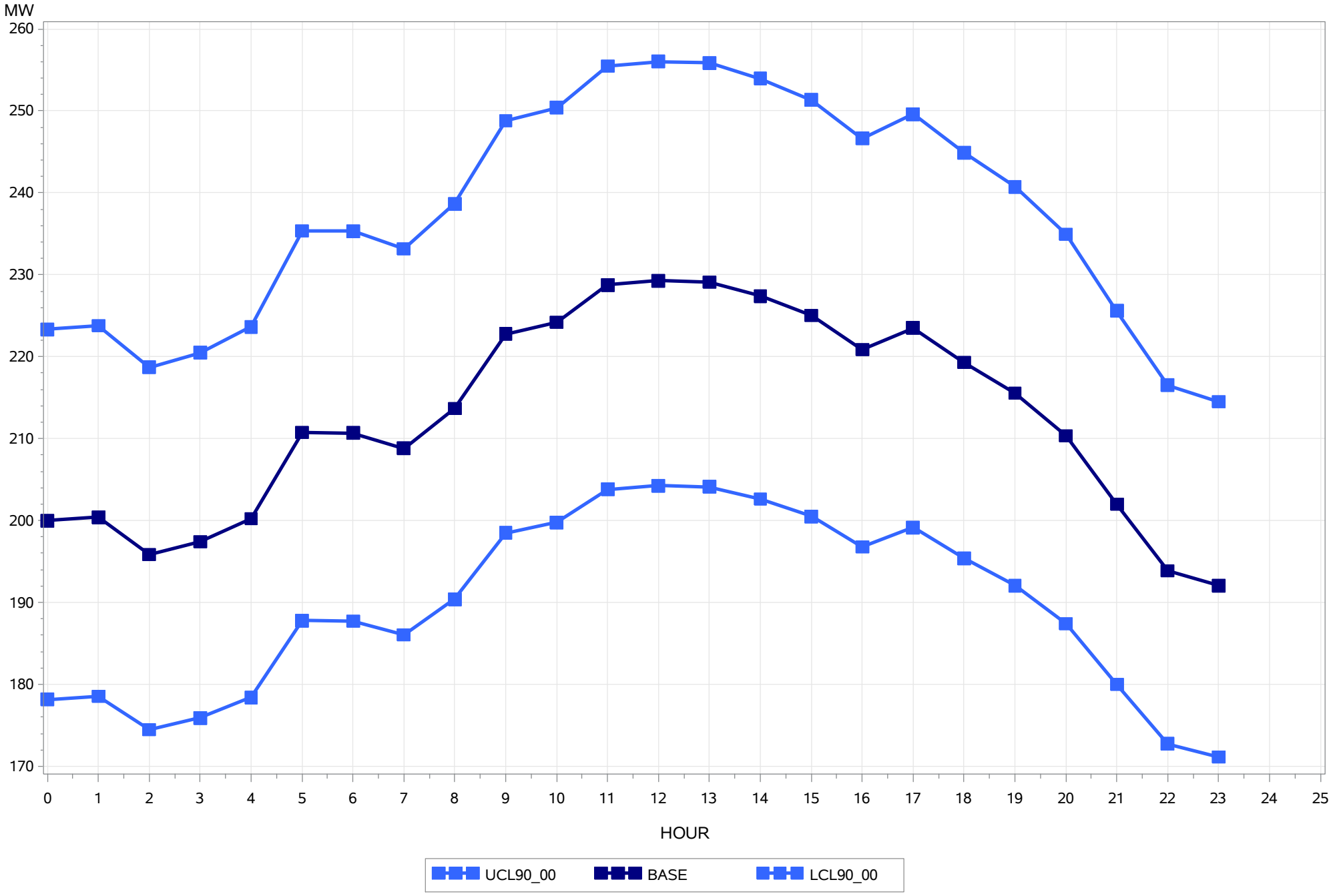

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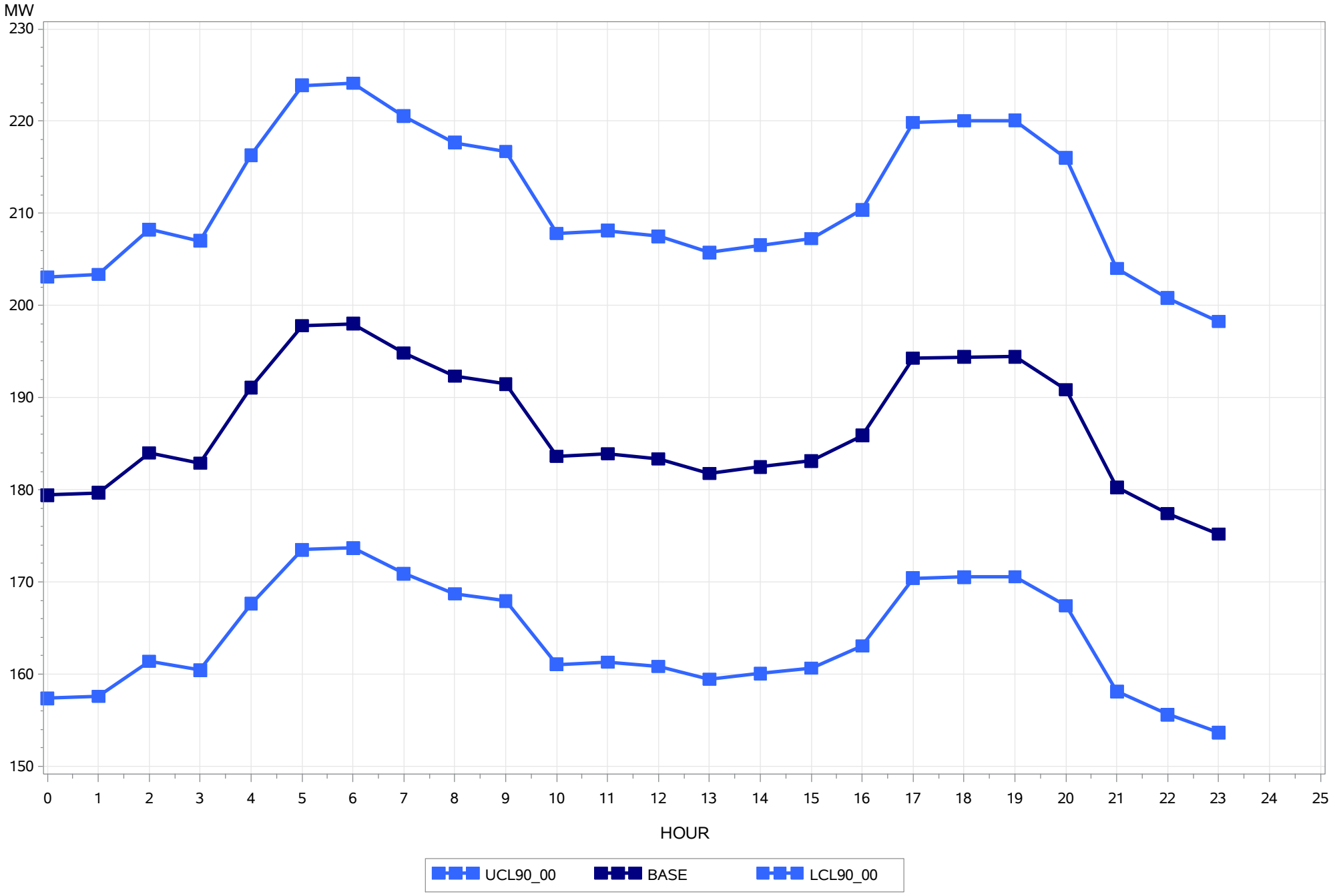
# Member Forecasted On Peak Demand Day for October 2021

**STATE OF WYOMING**

**Date of On Peak Day - 10/22/2021**



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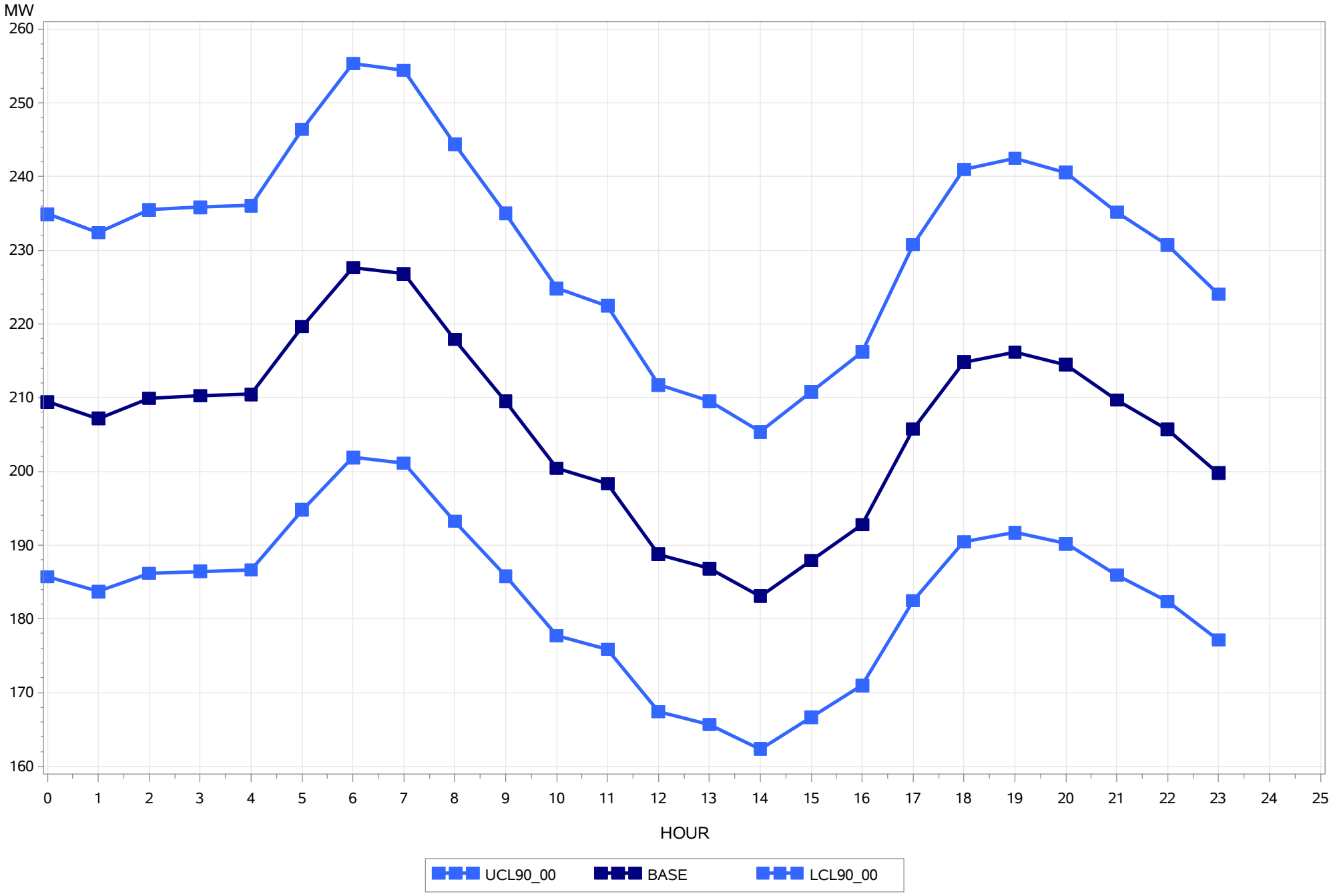
# Member Forecasted On Peak Demand Day for November 2021

**STATE OF WYOMING**

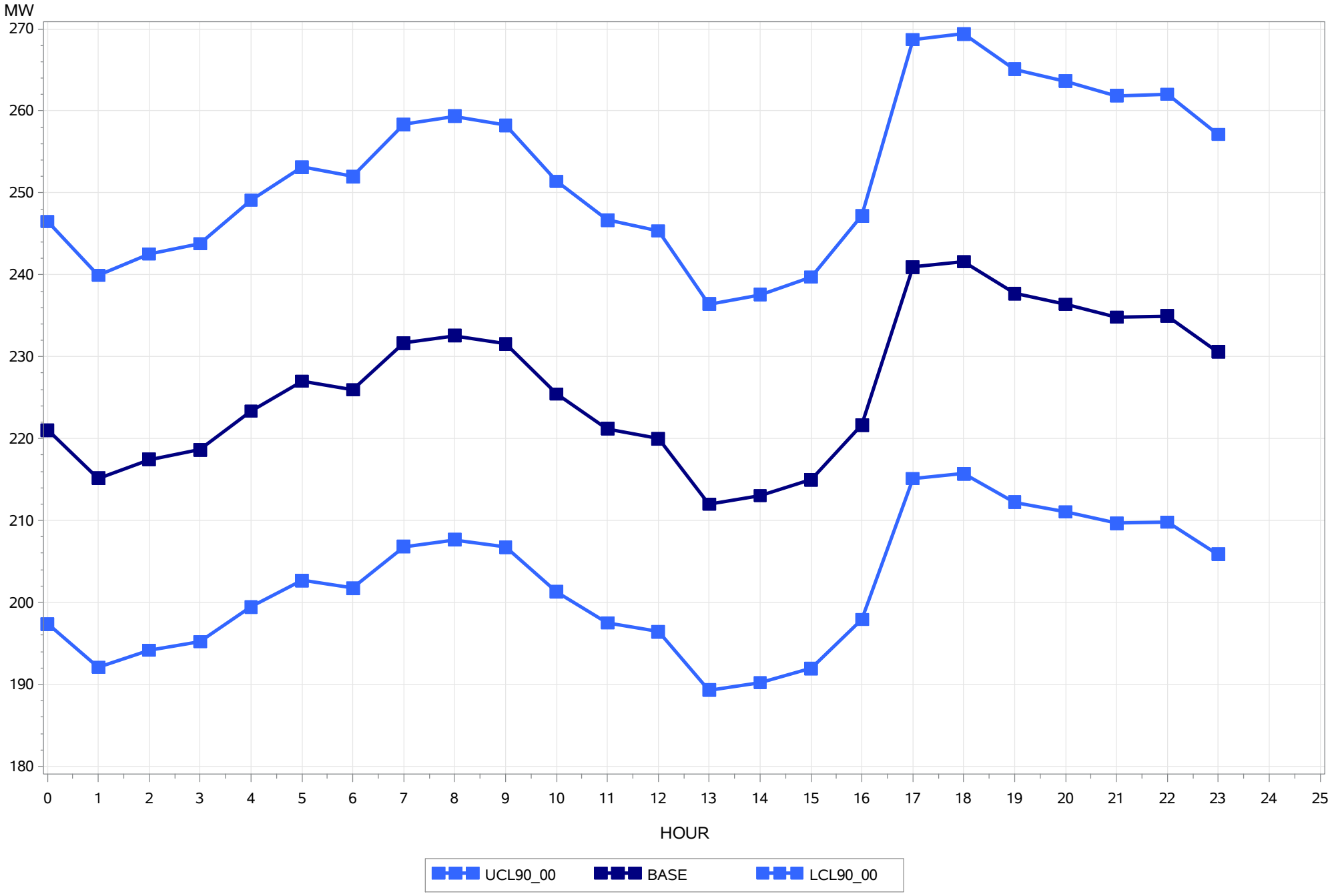
**Date of On Peak Day - 11/09/2021**



# Member Forecasted On Peak Demand Day for December 2021

**STATE OF WYOMING**

**Date of On Peak Day - 12/28/2021**



BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

| | |
|---|---|
| Federal Power Act Section 202(c) | ) |
| Emergency Order: Tri-State | ) |
| Generation and Transmission | ) |
| Association, Platte River Power | ) |
| Authority, Salt River Project, | ) |
| PacifiCorp, and Xcel Energy | ) |

Exhibit to
Motion to Intervene and Request for Rehearing and Stay of
Public Interest Organizations

Exhibit 2-52:
2023 Colorado Water Plan





# COLORADO WATER PLAN





COLORADO

Colorado Water Conservation Board

Department of Natural Resources

2023

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## ACRONYMS

| | |
|---|---|
| **A.C.T.** | Action Areas, Colorado Vision, Tools for Action |
| **AFY** | acre-feet per year |
| **ARPA** | American Rescue Plan Act |
| **ASO** | Airborne Snow Observatory |
| **ASR** | aquifer storage and recovery |
| **ATM** | Alternative Transfer Methods |
| **BIL** | Bipartisan Infrastructure Law |
| **BIP** | Basin Implementation Plan |
| **BLM** | U.S. Bureau of Land Management |
| **BOR** | Bureau of Reclamation |
| **BRAT** | Beaver Restoration Assessment Tool |
| **CASM** | Colorado Airborne Snow Measurement |
| **CBT** | Colorado-Big Thompson |
| **CDA** | Colorado Department of Agriculture |
| **CDPHE** | Colorado Department of Public Health and Environment |
| **CDSS** | Colorado's Decision Support Systems |
| **cfs** | cubic feet per second |
| **CGWS** | Colorado Growing Water Smart |
| **CoRHAF** | Colorado River Health Assessment Framework |
| **COSWAP** | Colorado Strategic Wildlife Action Program |
| **CPW** | Colorado Parks and Wildlife |
| **CREP** | Conservation Reserve Enhancement Program |
| **CRO** | Colorado Resiliency Office |
| **CROS** | Coordinated Reservoir Operations |
| **CRSPA** | Colorado River Storage Project Act |
| **CSFS** | Colorado State Forest Service |
| **CSU** | Colorado State University |
| **CWA** | Clean Water Act |
| **CWCB** | Colorado Water Conservation Board |
| **CWLI** | Colorado Water Loss Initiative |
| **CWRPDA** | Colorado Water Resources and Power Development Authority |
| **CWSA** | collaborative water sharing agreements |
| **DCP** | Drought Contingency Plan |
| **DFPC** | Division of Fire Prevention and Control |
| **DHSEM** | Division of Homeland Security & Emergency Management |
| **DI** | disproportionately impacted |
| **DM** | Demand Management |
| **DNR** | Department of Natural Resources |
| **DOLA** | Department of Local Affairs |
| **DPR** | direct potable reuse |
| **DRCOG** | Denver Regional Council of Governments |
| **DROA** | Drought Response Operations Agreement |
| **DWR** | Division of Water Resources |
| **EDI** | equity, diversity, and inclusion |
| **EJ** | environmental justice |
| **EPA** | Environmental Protection Agency |
| **EQIP** | Environmental Quality Incentives Program |
| **ESA** | Endangered Species Act |
| **FACE** | Future Avoided Cost Explorer |
| **FERC** | Federal Energy Regulatory Commission |
| **FHZ** | Fluvial Hazard Zone |
| **GIS** | geographic information systems |
| **GOCO** | Great Outdoors Colorado |
| **gpcd** | gallons per capita per day |
| **HB** | House Bill |
| **HUC** | Hydraulic Unit Code |
| **IBCC** | Interbasin Compact Committee |
| **IIJA** | Infrastructure Investment and Jobs Act |
| **IPR** | indirect potable reuse |
| **ISF** | Instream Flow |
| **IWMP** | integrated water management plan |
| **LiDAR** | light detection and ranging |
| **N/A** | not applicable |
| **NEPA** | National Environmental Policy Act |
| **NGO** | nongovernmental organization |
| **NLL** | natural lake level |
| **NPS** | National Park Service |
| **NRCS** | Natural Resources Conservation Service |
| **OEDIT** | Colorado Office of Economic Development and International Trade |
| **OREC** | Colorado Outdoor Recreation Industry Office |
| **OWL** | One Water Leaders |
| **PEPO** | Public Education Participation and Outreach |
| **PRRIP** | Platte River Recovery Implementation Program |
| **RGDSS** | Rio Grande Decision Support System |
| **RICD** | recreational in-channel diversion water right |
| **SB** | Senate Bill |

| | |
|---|---|
| **SDO** | State Demography Office |
| **SJRIP** | San Juan River Basin Recovery Implementation Program |
| **SMP** | stream management plan |
| **SNOTEL** | Snow Telemetry |
| **STEM** | science, technology, engineering, and mathematics |
| **SUIT** | Southern Ute Indian Tribe |
| **SWE** | snow water equivalent |
| **SWSI** | Statewide Water Supply Initiative |
| **TAG** | Technical Advisory Groups |
| **TMD** | transmountain diversion |
| **TMDL** | total maximum daily load |

| | |
|---|---|
| **UCEFRP** | Upper Colorado River Endangered Fish Recovery Program |
| **UMUT** | Ute Mountain Ute Tribe |
| **USACE** | United States Army Corps of Engineers |
| **USDA** | United States Department of Agriculture |
| **USFS** | United States Forest Service |
| **USFWS** | United States Fish and Wildlife Service |
| **USGS** | United States Geological Survey |
| **WQCC** | Water Quality Control Commission |
| **WQCD** | Water Quality Control Division |
| **WSRF** | Water Supply Reserve Fund |
| **YWG** | Yampa-White-Green Basin |



## COVER IMAGES AND STOCK PHOTO CREDITS

- Cover Birds take flight over the Yampa River near Steamboat Springs on the Daughenbaugh Ranch, Photo credit: M. Nager; Small Town and Suburban Sprawl In Colorado▲; Father and son fish by lake, dad looks at camera*; Aerial of green pastures and river, Photo credit: Kent Vertrees, Friends of the Yampa
- *Page v* A Woodhouse's Scrub-jay enjoys a Colorado winter morning*, Hiker standing in front of Snowmass Mountain at sunset*
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- *Page 237* Skiing father and child;▲ Family exploring in Colorado water, 2015 Water Plan
- *Page 240* Royal Gorge Bridge*

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# CWCB BOARD LETTER

Fellow Coloradan,

Thank you for opening the Colorado Water Plan. With this document, the Board and Staff of the Colorado Water Conservation Board (CWCB) seek to respond to this historic moment in time with a plan for thoughtful and bold initiative.

Much has changed since 2015, when the first Colorado Water Plan was finalized. The impacts of widespread drought, coupled with a global pandemic, challenged our communities with far-reaching uncertainties that shaped new water management realities. The pandemic pushed our stakeholders to begin meeting virtually, bringing a new way for people to connect, learn, and get involved with the work of planning for water. These experiences also highlighted the ways in which Colorado is connected by water.

Towns and farms on the Front Range are tied to high mountain streams on the West Slope through the complicated plumbing that brings water through the Continental Divide. Beyond these physical connections, there is a shared understanding that water supports Colorado's culture, communities, recreation, forests, and foods. The fresh produce, meat, and beer enjoyed in restaurants and kitchens around our state are supplied by farming and ranching families with diverse backgrounds and often multi-generational and historical ties to the land they steward. Coloradans value healthy rivers that drive robust recreation economies and provide important corridors for fish and wildlife, quality drinking water for cities and towns, and spaces for people to connect with nature. Colorado is the state we know and love because of its lakes, rivers, streams, wetlands, and aquifers. Because water inextricably links people across Colorado, our water management challenges must be faced together.



## GET INVOLVED—NOW IS THE TIME FOR ACTION

The West is experiencing growth in population and demand for water while our hydrology is becoming less predictable. Our temperatures have warmed, and the timing and amount of precipitation has changed, causing shifts in runoff and streamflows. It is clear this is not a temporary phenomenon, but rather a permanent trend toward aridification of the West. These changes, on top of existing concerns, present increased water quantity and water quality challenges especially as the rate and magnitude of ecosystem changes in Colorado have increased. These collective impacts have changed the way we think about water planning and shifted our collective approach to swift action.

The Colorado Water Plan was informed by robust stakeholder input and complex modeling that provides a data-driven understanding of our current water supply and potential future scenarios. The plan also highlights Colorado's values and follows four fundamental themes of Thriving Watersheds, Resilient Planning, Vibrant Communities, and Robust Agriculture through discussions of each of our major river basins. Most importantly, the plan sets forth ambitious yet attainable actions that will help Coloradans do more with less water, increase resiliency in the face of a changing climate, and ensure broad and diverse voices are included in future water management conversations.



The CWCB cannot do this important work alone, which is why the partner actions take into account close working relationships with sister agencies and the critical efforts of partner organizations, water users, and water managers across the state. This will require thoughtful and strategic partnerships across state agencies, Tribal Nations, local governments, water providers, and stakeholders. Colorado needs collaborative and creative solutions for balancing competing water demands for a finite resource. Whether by personal action or developing a Water Plan grant project proposal, you have a role to play.

The CWCB will also continue to lead through funding, collaboration, and the agency actions it will take. Importantly, the plan outlines a 10-year schedule for future Water Plan updates and includes the addition of an annual operations plan, which will allow the CWCB Board to consider yearly priorities and respond to shifting conditions and needs. Addressing Colorado's water challenges through partnerships and collective action ensures that competing demands for water resources decisions are balanced and maximize the benefits to current and future generations.

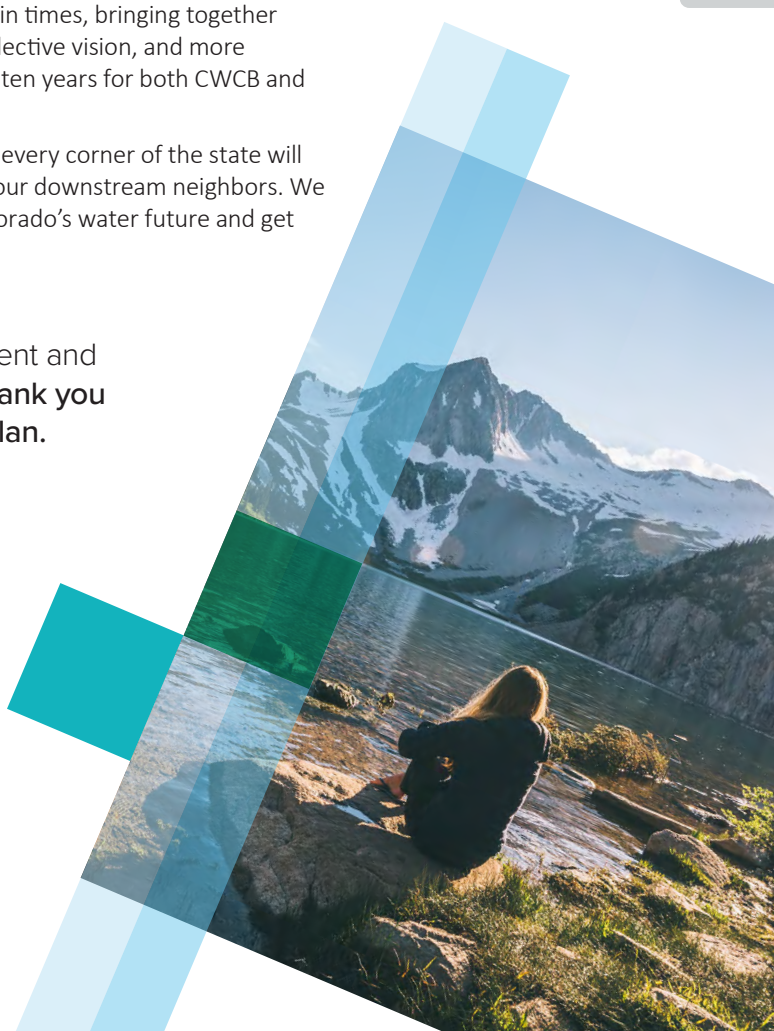
Colorado has always been a place where the adversity of the landscape has been tempered by its ability to inspire. While our challenges are great, our natural and human resources are too. We have a long and celebrated history of innovation in water management, and we are confident the people of Colorado will continue to rise to the occasion and take on the critical work of protecting our water supply future. The Colorado Water Plan offers a light through dark and uncertain times, bringing together wide-ranging interests and voices into a collective vision, and more importantly, a plan for action over the next ten years for both CWCB and local communities across the state.

The collective actions we take today across every corner of the state will increase water resilience for Colorado and our downstream neighbors. We hope you will consider your own role in Colorado's water future and get involved—now is the time for action.

On behalf of the staff and the current and past board members of CWCB, **thank you for reading the Colorado Water Plan.**

*—The Colorado Water Conservation Board*





# ACKNOWLEDGMENTS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**Vice Chair** - Greg Felt
**Other Directors**

Steve Anderson
Jessica Brody
Paul Bruchez
Heather Disney Dugan
Heather Dutton
Dan Gibbs
Kate Greenberg
Celene Hawkins
Rebecca Mitchell
Kevin Rein
Robert Sakata
Curran Trick
Phil Weiser

*Where agency directors are included in the list of CWCB Board members they are not included in their respective agencies below.*



*CWCB Board members (listed left to right): Robert Sakata, Paul Bruchez, Steve Anderson, Greg Felt, Dan Gibbs, Heather Dutton, Kevin Rein, Jackie Brown, Rebecca Mitchell, and Jessica Brody (not pictured: Heather Disney Dugan, Kate Greenberg, Celene Hawkins, Curran Trick, and Phil Weiser). Photo Credit: Russ Sands*

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- **Colorado Department of Public Health & Environment** - Tamara Allen, Michael Beck, Ron Falco, Aimee Konowal, Jojo La, Lauren McDonell, Joel Minor, Nathan Moore, MaryAnn Nason, Jeremey Neustifter, Nicole Rowan
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- **Colorado Oil and Gas Conservation Commission** - John Messner
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- **Governor and Lt. Governor's Office** - Governor Jared Polis and Lt. Governor Dianne Primavera
- **Other Support Governor and Lt. Governor Support Staff** - Jonathan Asher, Kathryn Redhorse
- **Department of Natural Resources Executive Director's Office*** - Chris Arend, Angela Boag, Carly Jacobs, Tim Mauck, Vanessa Mezal, Nate Pearson, Kelly Romero-Heaney

### OTHER STATE ENTITIES, GROUPS, ORGANIZATIONS, AND TASK FORCES WHO PROVIDED WATER PLAN INPUT:

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### COLORADO'S FEDERALLY RECOGNIZED TRIBES

Southern Ute Indian Tribe, Ute Mountain Ute Indian Tribe

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- Brenna Mefford, Lisa Wade, and Erin Wilson

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- **Community Language Cooperative**
- **Affinity Translation**

### FACILITATION SERVICES

- **Strategic By Nature** - Stacy Beaugh
- **Connected Realities** - GeGe Howard; Joy Lujan

CWCB would also like to recognize all the individuals and organizations who were kind enough to support CWCB staff with more than 100 events, with at least one in each of the state's 64 counties. We are grateful for your time, for sharing booth space, for providing tours, and for your partnership.

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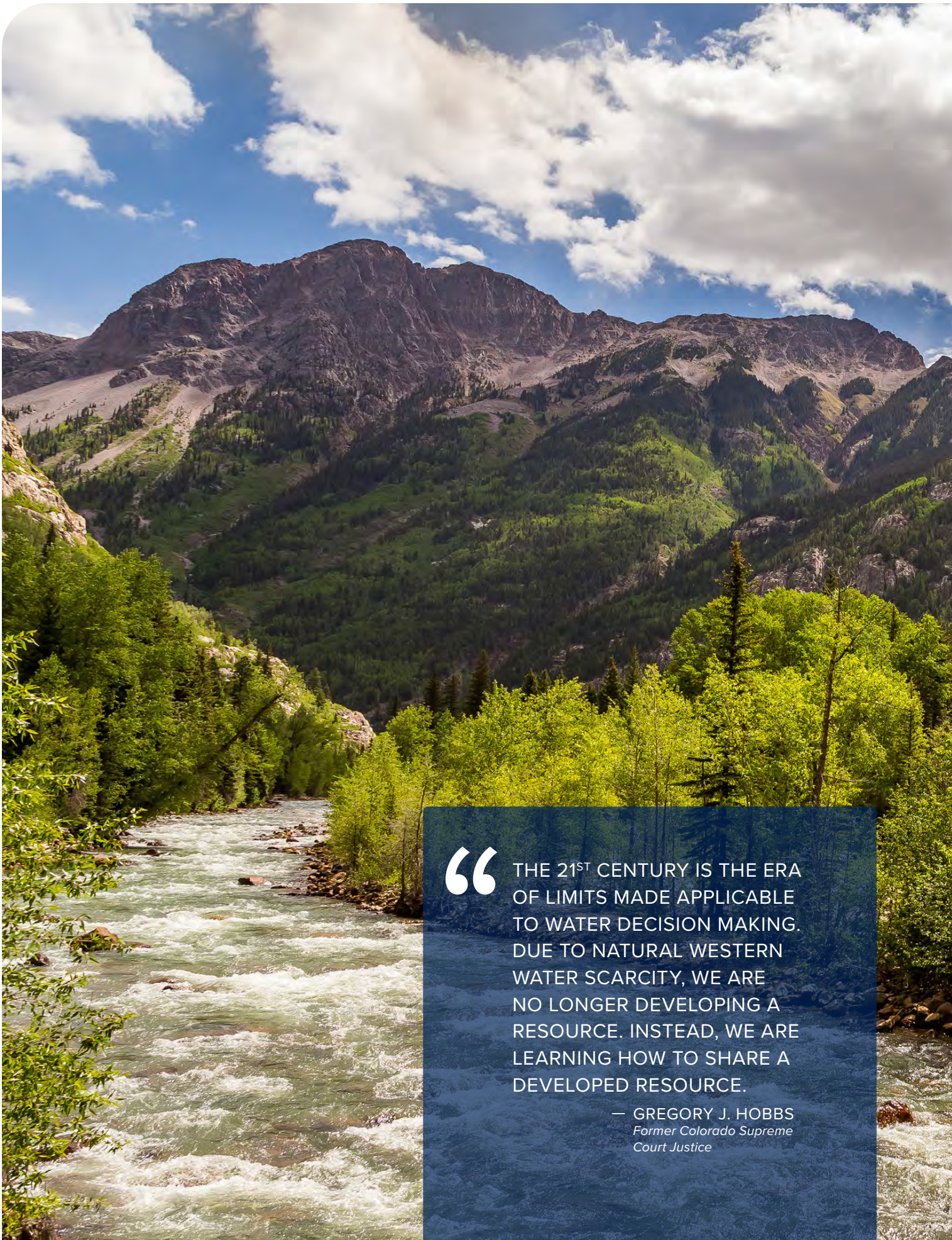
**Director participation noted through their role on the CWCB Board (See list above).*

CHAPTER 1

# OVERVIEW





> “THE 21ST CENTURY IS THE ERA OF LIMITS MADE APPLICABLE TO WATER DECISION MAKING. DUE TO NATURAL WESTERN WATER SCARCITY, WE ARE NO LONGER DEVELOPING A RESOURCE. INSTEAD, WE ARE LEARNING HOW TO SHARE A DEVELOPED RESOURCE.
>
> — GREGORY J. HOBBS
> *Former Colorado Supreme Court Justice*



Colorado's water touches every aspect of our daily lives. Those that depend on the water face unprecedented challenges that require all Coloradans to embrace a new water ethic. We must come together to protect this critical resource in increasingly innovative ways. The time for action is now.

As a headwaters state, water flows from Colorado's snow-capped peaks, through forests and streams, to cities and farms, and then returns to streams. Along the way, water supports habitat, wildlife, recreation, local food production, energy, industry, drinking water supplies, and more. Water connects us all. The importance of water in Colorado has long been recognized by the ancestral and Indigenous peoples of Colorado – the 48 Tribes that historically were the original stewards of this land include Colorado's two federally-recognized Tribes, the Southern Ute Indian Tribe (SUIT) and the Ute Mountain Ute Indian Tribe (UMUT). As noted by the Tribes, "Water is life."

Nearly 6 million Coloradans depend on the water from our major river basins as do 19 other states and Mexico, but that water supply is at risk. Population growth, long-term warming trends, major wildfires, aridification, and multi-year droughts are straining the system like never before.

We must understand these challenges, their associated risks, and the tools we can use to drive change. Tools that shape actions and policy to mitigate our risks can reshape the future. We must also be collaborative and understand the perspectives of water users from across the state. Basin Implementation Plans, developed by Colorado's nine basin roundtables, provide summaries of regional challenges, strategies to overcome them, and valuable data to inform the state's Water Plan. **The Colorado Water Plan sets the stage for a shared understanding of our risks and describes actions that collectively contribute to a stronger, more water-resilient Colorado.**

While Colorado faces enormous water challenges, its opportunities are tremendous. A secure water future will depend on our working together to uplift every area of the Water Plan. In reading this plan, it is important to know that the opportunity to take action is driven by you. Whatever your background, whatever your job, all Coloradans are a part of the solution. **Collaborative action needs to occur at every level, and the need for action has never been more urgent than now.**

# BUILDING ON PAST SUCCESS

The devastation of the 2002 drought and Hayman Fire launched a new era of resiliency planning and collaboration in Colorado that led to the creation of many of the state's grassroots water stakeholder groups, the Colorado Water Plan (Water Plan), and a continued investment in water. These efforts have made real progress since the 2015 Water Plan to better manage and fund Colorado's water, as noted below:

- Water conservation measures have **decreased statewide per capita water use by 5%.**
- Colorado Water Plan grants were established and funded **almost $55 million in projects covering every corner of the state.**
- Annual municipal leasing of **25,000 acre-feet** of agricultural water has helped cities and farms coexist.[1]
- **More than 25 new** stream management plans have been developed.
- **400,000 acre-feet** of storage has either been constructed or will soon be completed.[2]
- Water outreach, education, and messaging is estimated to have **reached up to 2.7 million people.**
- Legislation was **passed to integrate land use and water planning** in comprehensive plans.
- Reclaimed water regulations have been updated with **18 additional uses** to allow water reclamation in residential and commercial crop irrigation, among others. See Chapter 5 for more information on reclaimed water regulations.
- **62% of Coloradans** now live in communities whose leaders have been trained by the Growing Water Smart program to integrate water and land use planning.
- Multi-purpose, multi-benefit projects continue to receive grant funding and **more than $420 million in loans.**
- Watershed health received millions of dollars in support as statewide **watershed groups exceed 150.**
- Colorado voters **passed Proposition DD**[3] to dedicate funding for the Colorado Water Plan Grant Program.

These successes should be celebrated because they show significant progress, firm resolve, and a blueprint for collaborative action. Yet, the need for progress is now more urgent than ever. In the last two decades Colorado's population has increased by more than a million people. Several major wildfires have ignited our forests and grasslands, and drought, along with a larger trend in long-term warming and drying, known as aridification, continues to challenge water resources. Significant swaths of agricultural lands have been lost to buy and dry practices, water supply reductions, and urbanization; forests face continued risk from fire; and streams face new challenges for habitat protection.

In the face of this adversity, there has been a groundswell of collaborative action leading to real progress through holistic and multi-benefit projects. **It is increasingly important to make sure every water project or strategy uses water as wisely as possible, making it stretch as far as it can to realize its maximum value for cities, farms, streams, and people.** Doing so will require shared stewardship—a commitment to partnership in which the state government and every Coloradan must work together toward greater action.

**Colorado's nine basin roundtables have been instrumental in fostering our past successes and forming the future vision described in the Water Plan. Chapter 4 describes local challenges, recent achievements, and strategies to meet future needs that each basin roundtable provided in their Basin Implementation Plans - all of which inform the Water Plan.**

[1] Generalized findings from **Alternative Transfer Methods in Colorado, Status Update, Framework for Continued Support, and Recommendations for CWCB Action**

[2] Includes Chimney Hollow Reservoir (90,000 acre-feet), Glade Reservoir (170,000 acre-feet), Galeton Reservoir (45,600 acre-feet), Gross Reservoir Expansion (77,000 acre-feet), and Chatfield Reallocation (20,600 acre-feet)

[3] Proposition DD is a legislatively referred state statute on the November 2019 ballot that was ultimately codified in HB19-137 and provided funds from sports betting to be used, among other things, to fund the Water Plan through the creation of a Water Plan Implementation Cash Fund that is used to support CWCB's Colorado Water Plan Grant Program.

# EMPOWERING STAKEHOLDERS

As the stewards of the Water Plan and the agency charged to conserve, develop, protect, and manage Colorado's water for present and future generations, CWCB works with partners to foster action by funding local water projects through grants and loans. The CWCB also works on multiple programmatic efforts related to interstate compacts, flood mitigation, species protection, water project financing, agricultural support, and climate adaptation, all of which advance the goals of the Water Plan.

The CWCB does not build projects. It advances projects, often focusing on proven methods, by supporting project proponents with funding, analysis tools, technical assistance, programs, and policies that can help advance toward a future envisioned by the values and ideas in this Water Plan. The real power of the Water Plan is often driven by local and regional innovation, action, and project development that advance when stakeholders take action. This is readily apparent in the work that the state's nine legislatively-created basin roundtables completed to identify more than 1,800 local projects and plans in the lead-up to the Water Plan update (See Chapter 4).

**Meeting the moment extends well beyond what one agency or the entirety of the state government can do. The power of nearly 6 million Coloradans rallying to embrace a new water ethic in Colorado is what we need to be successful. The Water Plan is a call to action backed by governmental support that can catalyze local planning and projects.**

The Water Plan was informed by and built through stakeholder input. Basin-specific technical analyses, local stakeholder input, and statewide outreach informed the Water Plan by explaining local conditions, offering examples of successful projects, and gathering information about future projects needed for increased water resilience. The process involved ongoing work with basin roundtables and the Interbasin Compact Committee (IBCC), engagement with more than 1,200 stakeholders providing feedback during Water Plan scoping, multiple partners (agencies, Tribes, nongovernmental organizations [NGO], and members of the public) as well as a governor-created Water Equity Task Force. Stakeholders were also engaged during public review of the draft Water Plan through outreach events in all 64 Colorado counties, more than 2,000 submitted public observations on the draft plan, and more than 500 pages of public comment letters. Approximately 130 public comments were submitted in Spanish. This spirit of collaboration and the focus on Colorado water resilience is at the heart of the Water Plan, and implementing the Water Plan is critical to Colorado's future.

## PUBLIC ENGAGEMENT AND WATER EQUITY TASK FORCE

Building on years of ongoing grassroots input, CWCB included a scoping phase early in the Water Plan update process to evaluate the critical issues on stakeholders' minds and provide a platform to discuss CWCB's proposed direction for the Water Plan. As part of that effort, CWCB partnered with 20 agencies and NGOs to hold more than a dozen sector-specific workshops that engaged more than 1,200 stakeholders. Targeted interviews, online surveys, and an online stakeholder engagement platform supplemented the scoping outreach. This work gathered extensive input on stakeholder issues related to agricultural, municipal, watershed, and forest health needs. Themes that sparked a wide range of interest for incorporation in this Water Plan included addressing climate change and drought as well as the need to better recognize equity, diversity, and inclusion (EDI) in water issues.

Realizing that more time was needed to discuss EDI concerns and to bring in multiple perspectives, CWCB worked with the Department of Natural Resources (DNR) and the Governor's Office to create a year-long Water Equity Task Force that focused on developing a set of principles to help inform the update to the Water Plan. The 21-member task force included nine basin roundtable members (one from each roundtable), nine community members (one from each of the eight major river basins and the Denver metropolitan area), two members from each of Colorado's federally recognized Tribes, and one member from the Acequia community.

The Water Equity Task Force's guiding principles include a need to:

1. **Promote diversity** in career pathways in water-related fields through education and engagement.
2. **Promote collaboration**, new voices, and greater community engagement in water discussions.
3. **Recognize and address elements of the rural-urban divide** but focus on creating the rural-urban opportunity.
4. **Expand grant opportunities** to new audiences.
5. Support basin roundtables facilitating broad **community engagement and collaborative solutions.**

In addition to directly informing the Water Plan's development, CWCB uses these guiding principles to inform programming, policies, and engagement for the benefit of all Coloradans.

# USING THE PLAN



The Water Plan can be used in three primary ways:




## Use the plan to **become more informed about water and the future vision.**

The State of Colorado encourages its residents to be informed about water issues, but a 2021 Statewide Water Awareness Survey indicated that only 35% of Coloradans are confident they have the knowledge necessary to take action to manage our water use. Becoming more informed about water and the future vision is a critical first step. It creates ripple effects in what we value, how we invest, and how we conserve. It is also foundational to collaborative and inclusive water planning. For many, understanding the complex water challenges Colorado faces, the tools that can be used to find solutions, and Colorado's shared vision will be an important commitment.

*Opportunities to participate at this level include:*

- Support local water initiatives and projects
- Conserve water indoors and outdoors
- Practice wise stewardship of our rivers, lands, and natural resources
- Purchase water-saving products and locally grown food products
- Help promote water conservation and water outreach efforts
- Support local utility/city/county water conservation, local food, and resilience

## Use the plan as a platform to **become more engaged and take action to advance the vision.**

The Water Plan is a starting point, and it provides a larger framework for next-level action. If you can do more, whether because you are a water rights holder, a county commissioner, a water utility worker, a city planner, a business owner, a local leader, or a concerned resident looking to become more engaged, this is your time. The Water Plan provides your roadmap to identify and collaborate in implementing solutions to Colorado's water resources challenges.

*Opportunities to participate at this level include:*

- Attend a local water meeting (e.g., **basin roundtable**)
- Join a water-focused stakeholder group (e.g., NGO or basin roundtable)
- Start a local food or watershed group
- Apply for a grant to take action on the Water Plan
- Invest in water-efficient equipment in your home, business, or farm
- Work with your local community leaders to advance water projects

## Use the plan to **understand and leverage agency actions that advance the vision.**

For the State, the Water Plan serves as a call to action, shared leadership, and partnership. Elected officials throughout the state use the Water Plan to understand policy priorities. The executive, judicial, and legislative branches all have important roles in water discussions. Yet not one of these branches of government, nor the 180 or more state agencies, can create the necessary solutions alone. The State's role in the Water Plan is to use its collective resources to set a vision that is backed by funding and support tools to advance solutions.

*Opportunities to participate at this level include:*

- Attend a state water meeting (e.g., CWCB board meeting, basin roundtable meeting, legislative hearing, or committee meeting)
- Apply to join a water-focused board or commission
- Learn about and use State tools that have been developed to support action
- Engage with the State to create new supporting tools and processes
- Implement a local project that aligns with the Water Plan and, if possible, use state and federal resources to help fund the project
- Coordinate with local leaders to advance water policy



# PLAN ORGANIZATION

The Water Plan is structured to create a line of sight from Colorado's water values to the specific actions that address challenges. The four values in the Water Plan are based on extensive work with stakeholders and include:

- A productive economy that supports vibrant, sustainable cities, agriculture, recreation, and tourism
- An efficient and effective water infrastructure system
- A strong environment with healthy watersheds, rivers, streams, and wildlife
- An informed public with creative, forward-thinking solutions that are sustainable and resilient to changing conditions and result in strong, equitable communities that can adapt and thrive in the face of adversity

Most simply, these values represent the Colorado way of life—they are the things that make Colorado great. They are also the values that help inform the Water Plan organization and drive us to act. Taken as an acronym, our values drive us to A.C.T. through **A**ction Areas, **C**olorado Vision, and **T**ools for Action.

## Action Areas

The Water Plan is organized around four overarching action areas that loosely translate to cities, farms, streams, and people. The action areas are interrelated in that issues related to steams, river recreation, commerce, agriculture, diversity, and climate challenges often are interwoven and connected. The action areas are presented separately for organizational purposes, but the Water Plan also describes how they integrate. The action areas include:

**VIBRANT** COMMUNITIES: counties, municipalities, utilities, cities, towns, businesses, large industries, large and small urban and rural communities, etc.

**ROBUST** AGRICULTURE: established crops and farms, local food, orchards, ranching, ditch companies, acequias, urban agriculture, livestock, dairy, etc.

**THRIVING** WATERSHEDS: environment and recreation, river health, watershed health, forest health, wildfire mitigation, wildlife and aquatic species protection, etc.

**RESILIENT** PLANNING: climate adaptation, planning for climate extremes, embracing EDI (equity, diversity, inclusivity), education, outreach and engagement, supportive government, etc.



*Sunset over Yampa River, Photo credit: Kent Vertrees, Friends of the Yampa*

## Colorado Vision

The Colorado Vision, outlined in Chapter 6, describes how Colorado can achieve greater resilience across and within the four action areas as we look to the planning horizon of 2050. The vision for each action area first describes our desired future and then provides examples of the kinds of local actions stakeholders and partners can take to help realize the vision. Example actions are grouped into categories, including thoughtful storage, meeting future water needs, wise water use, healthy lands, and engaged partners. In addition, each action area vision describes ways in which it intersects and integrates with other action areas to demonstrate how the areas are intertwined and relate. The overarching vision for each action area is described below.



### **VIBRANT** COMMUNITIES

Holistic water management is essential for creating vibrant communities that balance water supply and demand needs to create a sustainable urban landscape. Colorado communities need resilient water supplies, water-conscious and attractive urban landscapes, planning that integrates land use and water solutions, and residents who understand the importance of water to their lives and economy. An integrated One Water ethic is necessary to create the transformative change needed to meet the moment and the future.[4]



### **ROBUST** AGRICULTURE

Agriculture not only provides food and fiber, but it is also important to Colorado's culture, heritage, and economy, and it faces unprecedented challenges. Innovations are needed to sustain irrigated agriculture, including strategies to stretch available water supplies, increase resiliency, enhance food production, and maintain profitability. Water supplies for Colorado's urban growth should not come at the expense of our rural communities through indiscriminate buy and dry methods. Collaborative partnerships among agriculture, environmental groups, and municipal water providers should be used to create multi-purpose projects that help keep irrigated lands in production and maintain ecosystem services.



### **THRIVING** WATERSHEDS

Colorado's watersheds hold the future of our water supply security. Comprehensive water resources planning should incorporate conditions of forests, streams, wetlands, and wildlife habitat. As our state's water source, the health of watersheds affects agriculture, downstream communities, recreation, tourism, and ecosystem function. Colorado will continue to follow a shared stewardship ethic to plan and implement multi-benefit projects to enhance the health of our watersheds.



### **RESILIENT** PLANNING

Water security is critical to the quality of life, environment, and economy of Colorado. The future is uncertain, and Colorado needs to be adaptive and resilient to face the challenges ahead. Water security roadmaps, inclusively developed at a local level and informed by strong state leadership, can identify acute and chronic risks to water supply, integrate local planning strategies, prioritize collaborative solutions, and build adaptive capacity and resilience.

[4] "One Water" means matching the right water to the right use. See glossary and Chapter 6 for details and graphic.

## Tools for Action

Tools for action are the means through which partners and agencies can address water issues and meet water needs. They include:

- Public outreach and education
- Funding
- Policy and regulatory changes
- Collaboration groups
- Watershed planning
- Climate adaptation
- Innovation
- Equity
- Endangered and threatened species recovery programs
- Natural hazard planning
- Land use and water planning integration
- Data collection and sharing
- Water storage
- Conveyance infrastructure
- Water efficiency and conservation programs
- Water reuse
- Collaborative water sharing agreements
- Stream/watershed restoration and enhancement
- Flow enhancement and maintenance

*Actions include:*

### 50 PARTNER ACTIONS

While the list of partner actions is limitless, the Water Plan describes approximately 50 ideas for potential actions that could be supported by Water Plan grants.

THESE INCLUDE ACTIONS AROUND

- Increased personal conservation
- Starting a new water initiative/project
- Developing collaborative solutions

### 50 AGENCY ACTIONS

The Water Plan includes 50 actions CWCB and supporting agencies will take to help advance local initiatives that support the wise development and conservation of water resources.

THESE INCLUDE ACTIONS AROUND

- Developing frameworks and convening groups
- Advancing research and science
- Creating support tools

## Tracking Progress

This Water Plan replaces the previous plan with transparent and trackable actions. Partner actions will be tracked through CWCB's increasingly modernized process for tracking of grants and loans as well as projects through the Project Database. As CWCB tracks the completion of the agency actions it leads, CWCB will also document major legislative and basin advancements that occur—especially where the State has played a role.

Specific actions that inform the CWCB Board's annual operating plans and processes like the next Technical Update offer opportunities to identify trends, analyze progress, and explore new data and information that will help CWCB stay nimble and responsive to shifting conditions. Implementing the plan embraces the spirit of resilience—being adaptive to both acute and chronic challenges. The Water Plan is meant to be broad and flexible enough to do all of this, but it needs you to help carry out the larger vision for water management in Colorado that uplifts all areas and people in the state.

## The Path Forward

The Water Plan is a call to action. Answering the call is a commitment to long-term water collaboration, resolve in the face of adversity, and developing creative solutions that allow Colorado to advance within the bounds of our legal framework. Coloradans must come together across diverse groups and geographies to envision and implement actions that will move us closer to a resilient water future. This is how we keep Colorado strong.

We are all interconnected from our headwaters to our homes by water and have a shared responsibility to it. However you interact with water—through your drinking water tap, buying food at your farmers market, enjoying the first snowfall, or recreating in one of Colorado's watersheds—you are a steward of the Water Plan. Embrace it.



## Water Plan Layout

Following this introduction, the Water Plan describes the critical elements of Colorado's history, geography, legal setting, and water-planning efforts. The background and context provide key pieces of information that guide the direction of the Water Plan.

- Water Plan methods for analyzing future water conditions (Chapter 2)
- Geography, variability, and use of water in our state and legal underpinnings for managing it (Chapter 3)
- Basin context and summary information, including potential costs of projects to meet future water needs (Chapter 4)
- Tools that can be used to take action (Chapter 5)
- Statewide vision for a more water-resilient Colorado, along with partner and agency actions (Chapter 6)
- Process for tracking and updating the Water Plan (Chapter 7)

## Accessing the Plan

The Water Plan allows the reader to engage at the levels that work best for them.

1. **Executive Summary** - High-level description and highlights of the Water Plan.
2. **Water Plan** (full document) - Foundational background information, future vision, and actions.
3. **CWCB Website** - Current CWCB efforts and background materials (cwcb.colorado.gov)

You can also find additional links and interactive resources at [cwcb.colorado.gov](cwcb.colorado.gov)

This updated Water Plan replaces the original Water Plan developed in 2015.



*Potato Harvest*
*Photo credit: Sinjin Eberle*

CHAPTER 2

# TECHNICAL ANALYSIS, SCENARIOS, and DRIVERS





# TECHNICAL ANALYSIS OVERVIEW

Following the launch of the Water Plan and the Basin Implementation Plans (BIP) in 2015, CWCB initiated the process of updating the underlying water supply and demand analyses, which culminated in the Analysis and Technical Update to the Colorado Water Plan (Technical Update), completed in 2019. The work began with the input of Technical Advisory Groups (TAG) that included representatives from across the state who provided expertise and advice on assumptions and methods for the Technical Update analyses. The resulting Technical Update (formerly known as the Statewide Water Supply Initiative or SWSI) established a new approach to statewide water analysis and data sharing.

The Technical Update leverages a significant investment of over three decades in statewide water modeling efforts, which began in 1992. To that end, the Technical Update provides a significant improvement in the scope, science, and approach to water supply planning. The approach positions Colorado for a streamlined and robust evaluation of its future water needs.

The 2015 Water Plan set an adaptive management framework for future water planning activities and described five plausible futures (or planning scenarios) under which demands, supplies, and gaps (difference between demand and supply) were to be estimated. The scenarios included new considerations, such as climate change, that were not a part of analyses prior to the 2019 Technical Update. In addition, CWCB has continued to work with the Division of Water Resources (DWR) to develop and refine consumptive use and surface water allocation models that were not ready for use in earlier analyses. The Technical Update data sets were developed to be readily updatable, and during the recent BIP update process some data sets were further refined with basin roundtable input. As a result of these factors, the Technical Update took a leap forward with a different and more robust approach to estimating future gaps.

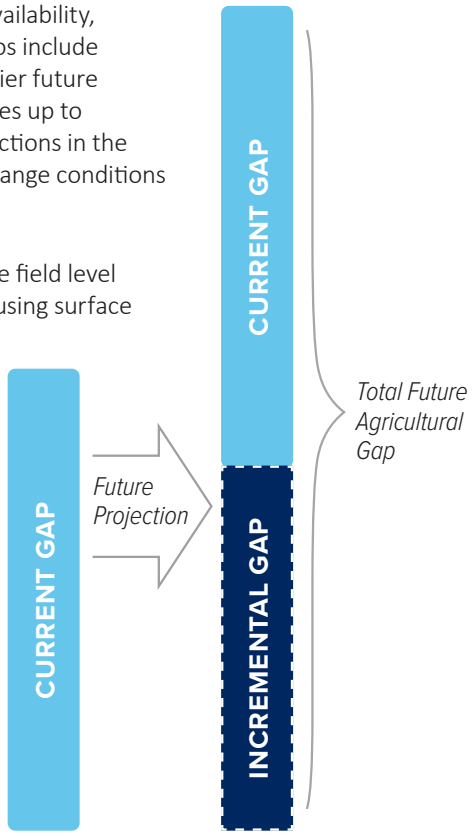
Click this link for more information on the Analysis and Technical Update to the Water Plan:
**Analysis and Technical Update**

Click this link for more information on Colorado's Decision Support Systems: **Colorado's Decision Support Systems**

Section 2 of the Technical Update (Volume 1) summarizes the methodologies used to estimate current and future municipal/industrial and agricultural demands, water supplies and potential gaps, and tools for evaluating environment and recreation needs. Volume 2 of the Technical Update includes technical memoranda with detailed descriptions of methodologies and analysis results. The methodologies used for the Technical Update build on previous datasets as well as new and improved data sources. To the extent possible, the Technical Update leveraged Colorado's investment in models and datasets developed through Colorado's Decision Support System (CDSS). Highlights of the new methodologies are described below.

- **Incorporation of scenario planning:** The 2015 Water Plan introduced scenario planning and included five scenarios that describe Colorado's potential water situation in the year 2050. The Technical Update conducted analyses of future demands, supplies, and additional water needs in the context of the potential future scenarios.
- **Municipal water use efficiency reporting data:** New data describing recent municipal water usage was employed to estimate municipal water demands. The data are collected and reported by water providers pursuant to House Bill (HB) 10-1051 (1051 data). The 1051 data were not available in prior SWSI efforts.
- **CDSS tools:** The Technical Update made extensive use of modeling tools available through CDSS. CDSS is a water resources data and modeling toolbox developed by CWCB and DWR for each of Colorado's major river basins for regional planning purposes. Tools in CDSS include HydroBase (a vast database of statewide water-related data), geographic information systems (GIS) data, surface water allocation models, and models that quantify consumptive use from crops and other vegetation. CDSS tools are available in most basins in the state. In basins where particular CDSS tools are not available, alternative methodologies were used to estimate demands and potential future gaps. The level of detail on hydrology, operations, and demands is appropriate for regional planning but does not capture daily changes in streamflow, routing of reservoir releases, or non-typical operations. As a result, the effect of local water uses on streamflows may not always be fully captured by the regional models.
- **Consideration of climate change:** The effects of climate change significantly influence hydrology, water demand and availability, and estimated gaps. Three of the five planning scenarios include assumptions and projections related to a hotter and drier future climate.[1] The analyses considered temperature increases up to 4.2 degrees Fahrenheit and were consistent with projections in the Colorado Climate Plan. Projections of future climate change conditions were not a part of past SWSI analyses.
- **Quantification of an agricultural gap:** Water demands and shortages for irrigated crops at the field level were estimated in SWSI 2010 but were not quantified using surface water modeling. Using the full suite of modeling tools available from CDSS made it possible to estimate agricultural gaps in the Technical Update under current and planning scenario conditions. Agricultural gaps are described in two ways:

  1. **Total Gap:** The overall shortage of water supplies (current plus potential incremental increases) to meet agricultural diversion demands required to provide full crop consumptive uses.
  2. **Incremental Gap:** The degree to which the gap could increase beyond what agriculture currently experiences under water shortage conditions.




[1] The planning scenarios developed for the Colorado Water Plan and the Technical Update were built on the foundational work of the multi-phase Colorado River Water Availability Study, Phase II (CRWAS-II). Detailed methodology and analysis results can be found in CRWAS-II Task 7: Climate Change Approach and Results.

- **Improved environment and recreation tools:** The Technical Update improved the data associated with environment and recreation attributes statewide. In addition, the Colorado Environmental Flow Tool (Flow Tool) was developed by CWCB to help assess potential flow conditions and associated ecological health in river segments in each basin. The Flow Tool was built on the framework of the Watershed Flow Evaluation Tool, a Colorado-specific application of a framework for assessing environmental flow needs at a regional scale. The tool uses flow data from the surface water allocation modeling developed for the Technical Update.

Link for the **Colorado Environmental Flow Tool**

## Risk of Future Water Shortages

In the Technical Update, the calculated difference between water supplies and water demands for current and future conditions in the municipal and industrial and agriculture sectors was labeled the "gap." Gaps were presented for each of the five planning scenarios to reflect future uncertainty. Because gaps are estimated for future scenarios, they represent a future risk that water supplies will not be adequate to fully meet municipal, industrial, and agricultural demands. The bigger the gap, the higher the risk that Colorado will not be able to meet its future water needs. In a similar vein, potential future risks for environmental and recreational attributes based on projected future flow conditions were evaluated in the Technical Update using the Flow Tool.

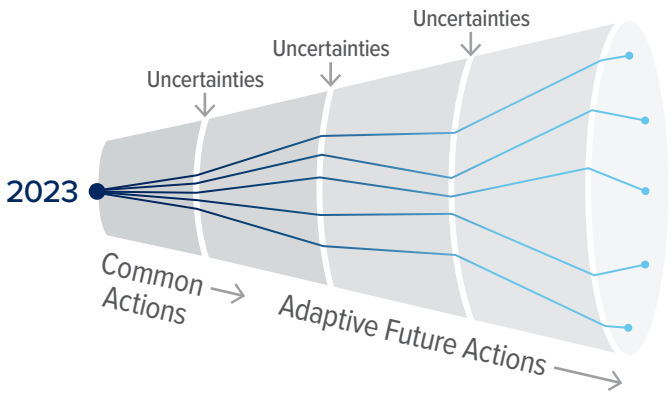
Identifying potential future risks to all sectors of water use was a key objective of the Technical Update. Risk identification is a starting point and is foundational for discussions about projects and strategies that will help lessen future risk. Chapter 3 of the Water Plan summarizes the results of analyses conducted during the Technical Update and enhanced during the BIP update process.

The Water Plan uses scenario planning to identify and assess several potential water futures that together capture the most relevant uncertainties and driving forces



# SCENARIO PLANNING APPROACH

The scenario planning process acknowledges that uncertainties exist in the future environmental state and social values of Colorado. As the time horizon increases, the uncertainty of these conditions increases as well. Particular scenarios can be based on assumptions about the states of future conditions. The scenario planning method is more sophisticated than a simplistic application of high-, medium-, and low-stress conditions (as were used in SWSI 2010).




## Plausible range of water futures in 2050

The Water Plan uses scenario planning to consider a wide range of possible futures according to the best available science and stakeholder input. The approach considers uncertainties in future climate conditions, social conditions (such as values and economics), and supply-demand conditions (e.g., energy, agricultural, and municipal needs).

The scenario planning method included the six general steps described below and is intended to be cyclical and adaptive.




1. Evaluate drivers that impact future water conditions
2. Identify the most uncertain and impactful drivers
3. Develop future scenarios that consider variations in the drivers
4. Quantify future supply and demand conditions for each scenario
5. Calculate potential future risks of water shortages
6. Develop projects or strategies to mitigate future risks

# IDENTIFICATION OF HIGH-IMPACT DRIVERS THAT INFLUENCE COLORADO'S WATER FUTURE

Before developing the 2015 Water Plan, CWCB initiated a multi-year stakeholder dialogue in conjunction with the nine basin roundtables and the IBCC to develop a methodology for projecting future water needs. The IBCC then developed a list of the following nine high-impact drivers that could greatly influence the direction of Colorado's water future. Several of these drivers are interrelated and can have integrated effects. The identification and monitoring of these nine drivers are important to understanding the direction of future water supply and demand.

## 1. SOCIAL / ENVIRONMENTAL VALUES

### DRIVER DESCRIPTION

Social/environmental values reflect the public's perception of water use, support of water and energy conservation, and allocation of water supply toward environmental uses. Social values influence drivers such as regulations and adoption of water efficiency technologies, but they also affect the types of solutions that Coloradans pursue to meet future water needs or respond to climate change. For example, social values can impact the degree to which residents voluntarily adopt water-efficient technologies that may cost them money. They can also influence the demand for local agricultural products and the desire to maintain open space. Personal experiences, education, and outreach impact the degree of public awareness of water issues, which in turn can affect the public's perception of the water supply solutions as well as recreation and environmental protections that are pursued.

### IMPACT ON WATER RESOURCES

If values trend toward greater water and energy conservation, new technologies may emerge that help conserve water. Also, development of new supplies may occur in ways that meet municipal and agricultural needs while preserving or enhancing the environment and providing recreational benefits.



## 2. POPULATION / ECONOMIC GROWTH

### DRIVER DESCRIPTION

Population growth is driven by both state and national economic trends and land use planning and development statewide (see Driver #3). Colorado's moderate climate and quality of life draw both permanent residents and tourists. Population and economic growth/decline is forecasted by the State Demography Office (SDO) using census data and understanding of economic drivers.

### IMPACT ON WATER RESOURCES

Population growth is a primary driver for municipal water demand and urbanization. Population change directly influences water use, while economic growth influences the types of water use (municipal, industrial, recreation, etc.). While Colorado's recent efforts to save water though efficiency and conservation have kept water demands steady in spite of growth, water demands are nevertheless projected to increase.

## 3. URBAN LAND USE / URBAN GROWTH PATTERNS

### DRIVER DESCRIPTION

Urban land use and growth considers both density of development, as well as urbanization of undeveloped and agricultural lands. Zoning and other decisions affecting population density in cities and towns impacts how water is used inside and outside of single- and multi-family housing. It also impacts the degree to which urban sprawl may occur in the future.

### IMPACT ON WATER RESOURCES

Population growth patterns can impact availability of water resources and how local governments use water (in-house use versus watering of green spaces). As urban areas grow into undeveloped areas of the watershed, both runoff into streams and water quality are affected. Finally, the urbanization of agricultural lands results in a shift of water use from the agricultural sector to the municipal sector, which can impact timing of use and return flows, wildlife habitat, and overall watershed health.

## 4. AVAILABILITY OF WATER EFFICIENCY TECHNOLOGIES

### DRIVER DESCRIPTION

Availability and adoption of water efficiency technology drives water demands from municipal, industrial, and agricultural perspectives. Increased efficiency can be implemented in all sectors (municipal, industrial, energy, agricultural) and can offset growth through decreased demand by individual users.

### IMPACT ON WATER RESOURCES

Indoor municipal demands can be reduced by installing low-flow fixtures, and outdoor demands are influenced by types of landscaping and efficiency of irrigation systems. On the agricultural side, irrigation efficiency technologies can reduce water losses on-farm and in ditches that deliver water from rivers and streams to farms. In addition, crop hybrids that are drought tolerant and crops that require less water can reduce irrigation demand.





## 5. CLIMATE CHANGE / WATER SUPPLY AVAILABILITY

### DRIVER DESCRIPTION

Climate change is the long-term shift in temperature and regional weather patterns that results in a range of projected future conditions that include a warmer and potentially drier future for Colorado.

### IMPACT ON WATER RESOURCES

Climate conditions impact both water supplies and water demands. Climate change may decrease streamflows and/or shift yearly streamflow patterns, which would impact agricultural, municipal, and industrial water supplies and create or increase risks for environment and recreation attributes. Higher temperatures associated with climate change will increase irrigation water demands for agricultural crops and outdoor urban landscapes and result in reduced return flows to streams.

## 6. LEVEL OF REGULATORY OVERSIGHT / CONSTRAINT

### DRIVER DESCRIPTION

Regulatory oversight includes the legal framework in Colorado and nationwide through which water is administered, developed, and managed. This includes oversight from DWR, Colorado Department of Public Health & Environment (CDPHE), U.S. Environmental Protection Agency (EPA), and others.

### IMPACT ON WATER RESOURCES

Regulatory constraints are influenced by social values, and they may drive changes in demands. For example, industrial water needs for energy extraction or thermoelectric energy production may be higher or lower in the future depending on state and local regulations and policies. Regulation can also drive the types of water supply solutions that stakeholders pursue. For example, the efficiency of permitting for certain types of water projects and the associated environmental mitigation requirements could influence their feasibility and cost.

## 7. AGRICULTURAL ECONOMICS / WATER DEMAND

### DRIVER DESCRIPTION

Agricultural conditions, such as the amount of irrigated land in production, crops grown, and climate influence irrigation water demands. Urbanization, municipal transfers of agricultural water supply, and availability of surface and groundwater supplies all influence the amount of agricultural land that will be in production in the future. In addition, demands and prices for local agricultural products affect the economic sustainability of continued agriculture and resulting demands for water.

### IMPACT ON WATER RESOURCES

Changes in the economics of the agricultural sector may impact the amount and types of crops grown, as well as the amount of land under irrigation. These changes will impact water demands for agricultural purposes.

## 8. ENERGY ECONOMICS / WATER DEMAND

### DRIVER DESCRIPTION

The energy sector uses water in a variety of ways, including direct use for hydropower, or indirect uses such as steam generation or cooling. Water needs for energy expand relative to population growth and current regulations, policies, and planning for the energy industry. These needs are also affected by the type of energy production that is used in the future and can be influenced by state and national energy policies.

### IMPACT ON WATER RESOURCES

As the sources of energy shift from non-renewable (coal and gas) to renewable (water, wind, and solar), the demand for water will shift as well. It is anticipated that renewable sources of energy will be less water consumptive.

## 9. MUNICIPAL AND INDUSTRIAL WATER DEMANDS

### DRIVER DESCRIPTION

The municipal and industrial sector serves the residents and businesses of Colorado with water. Municipal water demands are influenced by changes in other drivers such as population, urban land use, adoption of conservation measures, and climate.

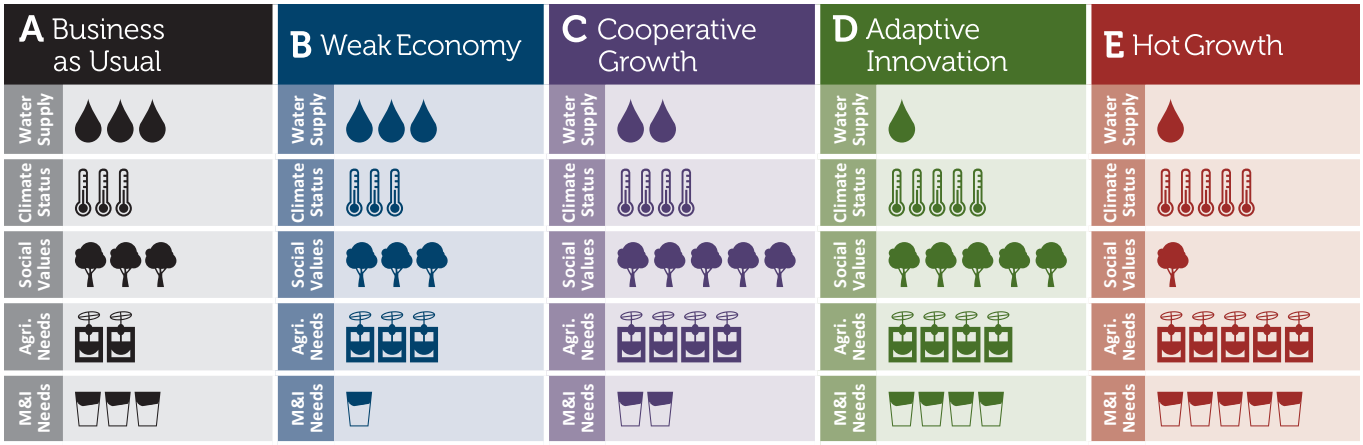
### IMPACT ON WATER RESOURCES

Water in Colorado is scarce, and as the population grows, increased municipal and industrial demand for water is met through development of new supplies (if available), at the expense of water from a different sector, or through water conservation.

Using these drivers, the IBCC developed five scenarios that represent how Colorado's water future might look in 2050, knowing that the future is unpredictable and will contain a mix of multiple scenarios. A simplified graphic and descriptions of the five scenarios are shown below. The icons for each scenario illustrate the increase and decrease in levels for the generalized drivers compared to current levels (the five icons represent the combined effects of the nine drivers). The scenario names portray the overall story that each scenario tells in its respective views of the future.

Click this link for more information on the scenarios (including full text descriptions of each scenario). Refer to the Technical Update to the Water Plan, Sections 2.1.3 and 2.1.4: **Analysis and Technical Update**

## SIMPLIFIED DESCRIPTION OF PLANNING SCENARIOS




**A Business as Usual**

- Population growth increases at trends predicted by the SDO.
- Future hydrology, per capita water demands, and adoption of conservation measures are similar to what's recently occurred.

**B Weak Economy**

- The world's economy slows, and the state's population growth is less than predicted.
- Hydrology is similar to recent patterns.
- This scenario puts the least amount of stress on future water supplies and is a bookend for scenarios.

**C Cooperative Growth**

- Climate is moderately warmer, and irrigation demands increase.
- Statewide population is similar to predictions by SDO, but it is distributed differently across the state.
- People seek to offset increased demands by more aggressively adopting water conservation.

**D Adaptive Innovation**

- Both scenarios assume that the climate is much warmer and drier and that population growth is higher than projected.
- The scenarios' primary differences revolve around conservation. In the Adaptive Innovation scenario, the state aggressively adopts conservation measures in both municipal and agricultural sectors. In the Hot Growth scenario, conservation is not a focus.

## Monitoring the Drivers

The Water Plan will be updated periodically as part of a robust planning cycle to evaluate the state's changing water conditions. Part of the periodic update process will include monitoring the status of water resources drivers and adjusting the planning scenarios based on observed trends. Some of the drivers (e.g., population, per capita municipal and industrial water demands) can be monitored with readily available data being collected by state and local entities. Other drivers (e.g., regulatory constraints and social/environmental values) may require specific data gathering, such as surveys or collaboration with other entities who collect these types of information.

The interactions of drivers and their impact on risk is complex, which underscores the need for consistent monitoring of the drivers during Water Plan implementation. If certain drivers increase future demand (e.g., urban or energy sector growth) or decrease water supply (e.g., drier climate, increased regulation), then the risk of a future water shortage may increase; however, the risk may not increase if new water-efficient technologies emerge.

### Monitoring and Uncertainty

**Our future is uncertain, which is why monitoring is critical for identifying trends and adaptively planning for the future. For example, using SDO population projections developed in 2017 as a foundation, the Technical Update estimated a 2050 statewide population range of 7.7 million to 9.3 million. The SDO estimate, prepared in October 2022, projects a 2050 population of 7.5 million, which corresponds closely to the projection in the Weak Economy scenario. Trends in population and other water supply and demand drivers need to be monitored so that the Water Plan can adapt to uncertain and changing future conditions. The CWCB monitors drivers, identifies changes in drivers during Technical Updates, evaluates whether recent changes signal long-term trends, and assesses how trends may affect the future.**



### Actions can be taken that are useful in any future scenario

**Near-term strategies and actions can be taken that provide benefits regardless of how the future unfolds (also known as "low regret strategies"). As future Technical Updates are conducted and the Water Plan is updated, new near-term strategies will be developed to adapt to conditions and lower our water-related risks.**

BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

| | |
|---|---|
| Federal Power Act Section 202(c) | ) |
| Emergency Order: Tri-State | ) |
| Generation and Transmission | ) |
| Association, Platte River Power | ) |
| Authority, Salt River Project, | ) |
| PacifiCorp, and Xcel Energy | ) |

Exhibit to
Motion to Intervene and Request for Rehearing and Stay of
Public Interest Organizations

Exhibit 2-53:
Colorado Sun Article

# In Colorado town built on coal, some families are moving on, even as Trump tries to boost industry

coloradosun.com/2025/12/08/colorado-coal-transition-jobs/

The Associated PressNews Agency, More by The Associated Press December 8, 2025




Matthew, Anna, Nathan and Matt Cooper prepare to drill a hole for a geothermal heat pump installation Thursday, Oct. 9, 2025, in Hamilton, Colo. (AP Photo/Brittany Peterson)

**By Brittany Peterson and Jennifer McDermott,** *The Associated Press*

**CRAIG —** The Cooper family knows how to work heavy machinery. The kids could run a hay baler by their early teens, and two of the three ran monster-sized drills at the coal mines along with their dad.

But learning to maneuver the shiny red drill they use to tap into underground heat feels different. It's a critical part of the new family business, High Altitude Geothermal, which installs geothermal heat pumps that use the Earth's constant temperature to heat and cool buildings. At stake is not just their livelihood but a century-long family legacy of producing energy in Moffat County.

Like many families here, the Coopers have worked in coal for generations — and in oil before that. That's ending for Matt Cooper and his son Matthew as one of three coal mines in the area closes in a statewide shift to cleaner energy.

"People have to start looking beyond coal," said Matt Cooper. "And that can be a multitude of things. Our economy has been so focused on coal and coal-fired power plants. And we need the diversity."

Many countries and about half of U.S. states are moving away from coal, citing environmental impacts and high costs. Burning coal emits carbon dioxide that traps heat in the atmosphere, warming the planet.

President Donald Trump has boosted coal as part of his agenda to promote fossil fuels. He's trying to save a declining industry with executive orders, large sales of coal from public lands, regulatory relief and offers of hundreds of millions of dollars to restore coal plants.



A drill sits outside the Cooper family ranch as they work to install a geothermal heat pump Thursday, Oct. 9, 2025, in Hamilton, Colo. (AP Photo/Brittany Peterson)

That's created uncertainty in places like Craig. As some families like the Coopers plan for the next stage of their careers, others hold out hope Trump will save their plants, mines and high-paying jobs.

Matt and Matthew Cooper work at the Colowyo Mine near Meeker, though active mining has ended and site cleanup begins in January.

The mine employs about 130 workers and supplies Craig Generating Station, a 1,400-megawatt coal-fired plant. Tri-State Generation and Transmission Association is planning to close Craig's Unit 1 by year's end for economic reasons and to meet legal requirements for reducing emissions. The other two units will close in 2028.

Xcel Energy owns coal-fired Hayden Station, about 30 minutes away. It said it doesn't plan to change retirement dates for Hayden, though it's extending another coal unit in Pueblo in part due to increased demand for electricity.

The Craig and Hayden plants together employ about 200 people.

Craig residents have always been entrepreneurial and that spirit will get them through this transition, said Kirstie McPherson, board president for the Craig Chamber of Commerce. Still, she said, just about everybody here is connected to coal.

"You have a whole community who has always been told you are an energy town, you're a coal town," she said. "When that starts going away, beyond just the individuals that are having the identity crisis, you have an entire culture, an entire community that is also having that same crisis."

## Phasing out coal

Coal has been central to Colorado's economy since before statehood, but it's generally the most expensive energy on today's grid, said Democratic Gov. Jared Polis.

"We are not going to let this administration drag us backwards into an overreliance on expensive fossil fuels," Polis said in a statement.

Nationwide, coal power was 28% more expensive in 2024 than it was in 2021, costing consumers $6.2 billion more, according to a June analysis from Energy Innovation. The nonpartisan think tank cited significant increases to run aging plants as well as inflation.

Colorado's six remaining coal-fired power plants are scheduled to close or convert to natural gas, which emits about half the carbon dioxide as coal, by 2031. The state is rapidly adding solar and wind that's cheaper and cleaner than legacy coal plants. Renewable energy provides more than 40% of Colorado's power now and will pass 70% by the end of the decade, according to statewide utility plans.




Matt Cooper and his kids Anna, Nathan and Matthew prepare to drill a hole for a geothermal heat pump installation Thursday, Oct. 9, 2025, in Hamilton, Colo. (AP PhotoBrittany Peterson)

Nationwide, wind and solar growth has remained strong, producing more electricity than coal in 2025, as of the latest data in October, according to energy think tank Ember.

But some states want to increase or at least maintain coal production. That includes top coal state Wyoming, where the Wyoming Energy Authority said Trump is breathing welcome new life into its coal and mining industry.

## Planning for the future

The Coopers have gone all-in on geothermal.

“Maybe we’ll never go back to coal,” Matt Cooper said. “We haven’t (gone) back to oil and gas, so we might just be geothermal people for quite some time, maybe generations, and then eventually something else will come along.”

While the Coopers were learning to use their drill in October, Wade Gerber was in downtown Craig distilling grain neutral spirits — used to make gin and vodka — on a day off from the Craig Station power plant. Gerber stepped over his corgis, Ali and Boss, and onto a stepladder to peer into a massive stainless steel pot where he was heating wheat and barley.

Gerber's spent three decades in coal. When closure plans were announced four years ago, he, his wife Tenniel and their friend McPherson brainstormed business ideas.



The Craig Station coal-burning power plant in Moffat County, here on Feb. 14, 2024, is expected to close in a few years. (Hugh Carey, The Colorado Sun)

"With my background in plumbing and electrical from the plant it's like, oh yeah, I can handle that part of it," Gerber said about distilling. "This is the easy part."

He used Tri-State's education subsidies for classes in distilling, while other co-workers learned to fix vehicles or repair guns to find new careers. While some plan to leave town, Gerber is opening Bad Alibi Distillery. McPherson and Tenniel Gerber are opening a cocktail bar next door.

Everyone in town hopes Trump will step in to extend the plant's life, Gerber said. Meanwhile, they're trying to define a new future for Craig in a nerve-wracking time.

"For me, my products can go elsewhere. I don't necessarily have to sell it in Craig, there's that avenue. For someone relying on Craig, it's even scarier," he said.

## Questioning the coal rollback

Tammy Villard owns a gift shop, Moffat Mercantile, with her husband. After the coal closures were announced, they opened a commercial print shop too, seeing it as a practical choice for when so many high-paying jobs go away.

Villard, who spent a decade at Colowyo as administrative staff, said she doesn't understand how the state can throw the switch to turn off coal and still have reliable electricity. She wants the state to slow down.

Villard describes herself as a moderate Republican. She said political swings at the federal level — from the green energy push in the last administration to doubling down on fossil fuels in this one — aren't helpful.

"The pendulum has to come back to the middle," she said, "and we are so far out to either side that I don't know how we get back to that middle."

## Type of Story: News Service

Produced externally by an organization we trust to adhere to high journalistic standards.



## The Associated PressNews Agency

The Associated Press is an independent, not-for-profit news cooperative, serving member newspapers and broadcasters in the U.S., and other customers around the world. The Colorado Sun is proud to be one of them. AP journalists in more... More by The Associated Press

BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

| | |
|---|---|
| Federal Power Act Section 202(c) | ) |
| Emergency Order: Tri-State | ) |
| Generation and Transmission | ) |
| Association, Platte River Power | ) |
| Authority, Salt River Project, | ) |
| PacifiCorp, and Xcel Energy | ) |

Exhibit to
Motion to Intervene and Request for Rehearing and Stay of
Public Interest Organizations

Exhibit 2-54:
PacifiCorp FERC Form 1

| THIS FILING IS |
| --- |
| Item 1: ☑ An Initial (Original) Submission OR ☐ Resubmission No. |

# FERC FINANCIAL REPORT
# FERC FORM No. 1: Annual Report of Major Electric Utilities, Licensees and Others and Supplemental Form 3-Q: Quarterly Financial Report

These reports are mandatory under the Federal Power Act, Sections 3, 4(a), 304 and 309, and 18 CFR 141.1 and 141.400. Failure to report may result in criminal fines, civil penalties and other sanctions as provided by law. The Federal Energy Regulatory Commission does not consider these reports to be of confidential nature

| **Exact Legal Name of Respondent (Company)** | Year/Period of Report |
| --- | --- |
| PacifiCorp | End of: 2024/ Q4 |

# GENERAL INFORMATION

### Purpose

FERC Form No. 1 (FERC Form 1) is an annual regulatory requirement for Major electric utilities, licensees and others (18 C.F.R. § 141.1). FERC Form No. 3-Q ( FERC Form 3-Q) is a quarterly regulatory requirement which supplements the annual financial reporting requirement (18 C.F.R. § 141.400). These reports are designed to collect financial and operational information from electric utilities, licensees and others subject to the jurisdiction of the Federal Energy Regulatory Commission. These reports are also considered to be non-confidential public use forms.

### Who Must Submit

Each Major electric utility, licensee, or other, as classified in the Commission's Uniform System of Accounts Prescribed for Public Utilities, Licensees, and Others Subject To the Provisions of The Federal Power Act (18 C.F.R. Part 101), must submit FERC Form 1 (18 C.F.R. § 141.1), and FERC Form 3-Q (18 C.F.R. § 141.400).

Note: Major means having, in each of the three previous calendar years, sales or transmission service that exceeds one of the following:

one million megawatt hours of total annual sales,

100 megawatt hours of annual sales for resale,

500 megawatt hours of annual power exchanges delivered, or

500 megawatt hours of annual wheeling for others (deliveries plus losses).

### What and Where to Submit

Submit FERC Form Nos. 1 and 3-Q electronically through the eCollection portal at https://eCollection.ferc.gov, and according to the specifications in the Form 1 and 3-Q taxonomies.

The Corporate Officer Certification must be submitted electronically as part of the FERC Forms 1 and 3-Q filings.

Submit immediately upon publication, by either eFiling or mail, two (2) copies to the Secretary of the Commission, the latest Annual Report to Stockholders. Unless eFiling the Annual Report to Stockholders, mail the stockholders report to the Secretary of the Commission at:
Secretary
Federal Energy Regulatory Commission 888 First Street, NE
Washington, DC 20426

For the CPA Certification Statement, submit within 30 days after filing the FERC Form 1, a letter or report (not applicable to filers classified as Class C or Class D prior to January 1, 1984). The CPA Certification Statement can be either eFiled or mailed to the Secretary of the Commission at the address above.

The CPA Certification Statement should:

Attest to the conformity, in all material aspects, of the below listed (schedules and pages) with the Commission's applicable Uniform System of Accounts (including applicable notes relating thereto and the Chief Accountant's published accounting releases), and

Be signed by independent certified public accountants or an independent licensed public accountant certified or licensed by a regulatory authority of a State or other political subdivision of the U. S. (See 18 C.F.R. §§ 41.10-41.12 for specific qualifications.)

| Schedules | Pages |
|---|---|
| Comparative Balance Sheet | 110-113 |
| Statement of Income | 114-117 |
| Statement of Retained Earnings | 118-119 |
| Statement of Cash Flows | 120-121 |
| Notes to Financial Statements | 122-123 |

The following format must be used for the CPA Certification Statement unless unusual circumstances or conditions, explained in the letter or report, demand that it be varied. Insert parenthetical phrases only when exceptions are reported.

"In connection with our regular examination of the financial statements of [COMPANY NAME] for the year ended on which we have reported separately under date of [DATE], we have also reviewed schedules [NAME OF SCHEDULES] of FERC Form No. 1 for the year filed with the Federal Energy Regulatory Commission, for conformity in all material respects with the requirements of the Federal Energy Regulatory Commission as set forth in its applicable Uniform System of Accounts and published accounting releases. Our review for this purpose included such tests of the accounting records and such other auditing procedures as we considered necessary in the circumstances.

Based on our review, in our opinion the accompanying schedules identified in the preceding paragraph (except as noted below) conform in all material respects with the accounting requirements of the Federal Energy Regulatory Commission as set forth in its applicable Uniform System of Accounts and published accounting releases." The letter or report must state which, if any, of the pages above do not conform to the Commission's requirements. Describe the discrepancies that exist.

Filers are encouraged to file their Annual Report to Stockholders, and the CPA Certification Statement using eFiling. Further instructions are found on the Commission's website at https://www.ferc.gov/ferc-online/ferc-online/frequently-asked-questions-faqs-efilingferc-online.

Federal, State, and Local Governments and other authorized users may obtain additional blank copies of FERC Form 1 and 3-Q free of charge from https://www.ferc.gov/general-information-0/electric-industry-forms.

### When to Submit

FERC Forms 1 and 3-Q must be filed by the following schedule:

FERC Form 1 for each year ending December 31 must be filed by April 18th of the following year (18 CFR § 141.1), and

FERC Form 3-Q for each calendar quarter must be filed within 60 days after the reporting quarter (18 C.F.R. § 141.400).

### Where to Send Comments on Public Reporting Burden.

The public reporting burden for the FERC Form 1 collection of information is estimated to average 1,168 hours per response, including the time for reviewing instructions, searching existing data sources, gathering and maintaining the data-needed, and completing and reviewing the collection of information. The public reporting burden for the FERC Form 3-Q collection of information is

For any page(s) that is not applicable to the respondent, omit the page(s) and enter "NA," "NONE," or "Not Applicable" in column (d) on the List of Schedules, pages 2 and 3.

Enter the month, day, and year for all dates. Use customary abbreviations. The "Date of Report" included in the header of each page is to be completed only for resubmissions (see VII. below).

Generally, except for certain schedules, all numbers, whether they are expected to be debits or credits, must be reported as positive. Numbers having a sign that is different from the expected sign must be reported by enclosing the numbers in parentheses.

For any resubmissions, please explain the reason for the resubmission in a footnote to the data field.

Do not make references to reports of previous periods/years or to other reports in lieu of required entries, except as specifically authorized.

Wherever (schedule) pages refer to figures from a previous period/year, the figures reported must be based upon those shown by the report of the previous period/year, or an appropriate explanation given as to why the different figures were used.

Schedule specific instructions are found in the applicable taxonomy and on the applicable blank rendered form.

Definitions for statistical classifications used for completing schedules for transmission system reporting are as follows:

FNS - Firm Network Transmission Service for Self. "Firm" means service that can not be interrupted for economic reasons and is intended to remain reliable even under adverse conditions. "Network Service" is Network Transmission Service as described in Order No. 888 and the Open Access Transmission Tariff. "Self" means the respondent.

FNO - Firm Network Service for Others. "Firm" means that service cannot be interrupted for economic reasons and is intended to remain reliable even under adverse conditions. "Network Service" is Network Transmission Service as described in Order No. 888 and the Open Access Transmission Tariff.

LFP - for Long-Term Firm Point-to-Point Transmission Reservations. "Long-Term" means one year or longer and" firm" means that service cannot be interrupted for economic reasons and is intended to remain reliable even under adverse conditions. "Point-to-Point Transmission Reservations" are described in Order No. 888 and the Open Access Transmission Tariff. For all transactions identified as LFP, provide in a footnote the termination date of the contract defined as the earliest date either buyer or seller can unilaterally cancel the contract.

OLF - Other Long-Term Firm Transmission Service. Report service provided under contracts which do not conform to the terms of the Open Access Transmission Tariff. "Long-Term" means one year or longer and "firm" means that service cannot be interrupted for economic reasons and is intended to remain reliable even under adverse conditions. For all transactions identified as OLF, provide in a footnote the termination date of the contract defined as the earliest date either buyer or seller can unilaterally get out of the contract.

SFP - Short-Term Firm Point-to-Point Transmission Reservations. Use this classification for all firm point-to-point transmission reservations, where the duration of each period of reservation is less than one-year.

NF - Non-Firm Transmission Service, where firm means that service cannot be interrupted for economic reasons and is intended to remain reliable even under adverse conditions.

OS - Other Transmission Service. Use this classification only for those services which can not be placed in the above-mentioned classifications, such as all other service regardless of the length of the contract and service FERC Form. Describe the type of service in a footnote for each entry.

AD - Out-of-Period Adjustments. Use this code for any accounting adjustments or "true-ups" for service provided in prior reporting periods. Provide an explanation in a footnote for each adjustment.

DEFINITIONS

Commission Authorization (Comm. Auth.) -- The authorization of the Federal Energy Regulatory Commission, or any other Commission. Name the commission whose authorization was obtained and give date of the authorization.

Respondent -- The person, corporation, licensee, agency, authority, or other Legal entity or instrumentality in whose behalf the report is made.

# EXCERPTS FROM THE LAW

**Federal Power Act, 16 U.S.C. § 791a-825r**

Sec. 3. The words defined in this section shall have the following meanings for purposes of this Act, to with:

'Corporation' means any corporation, joint-stock company, partnership, association, business trust, organized group of persons, whether incorporated or not, or a receiver or receivers, trustee or trustees of any of the foregoing. It shall not include 'municipalities, as hereinafter defined;

'Person' means an individual or a corporation;

'Licensee, means any person, State, or municipality Licensed under the provisions of section 4 of this Act, and any assignee or successor in interest thereof;

'municipality means a city, county, irrigation district, drainage district, or other political subdivision or agency of a State competent under the Laws thereof to carry and the business of developing, transmitting, unitizing, or distributing power; .....

"project' means. a complete unit of improvement or development, consisting of a power house, all water conduits, all dams and appurtenant works and structures (including navigation structures) which are a part of said unit, and all storage, diverting, or fore bay reservoirs directly connected therewith, the primary line or lines transmitting power there from to the point of junction with the distribution system or with the interconnected primary transmission system, all miscellaneous structures used and useful in connection with said unit or any part thereof, and all water rights, rights-of-way, ditches, dams, reservoirs, Lands, or interest in Lands the use and occupancy of which are necessary or appropriate in the maintenance and operation of such unit;

"Sec. 4. The Commission is hereby authorized and empowered

'To make investigations and to collect and record data concerning the utilization of the water 'resources of any region to be developed, the water-power industry and its relation to other industries and to interstate or foreign commerce, and concerning the location, capacity, development costs, and relation to markets of power sites; ... to the extent the Commission may deem necessary or useful for the purposes of this Act."

"Sec. 304.

Every Licensee and every public utility shall file with the Commission such annual and other periodic or special* reports as the Commission may by rules and regulations or other prescribe as necessary or appropriate to assist the Commission in the proper administration of this Act. The Commission may prescribe the manner and FERC Form in which such reports shall be made, and require from

estimated to average 168 hours per response.

Send comments regarding these burden estimates or any aspect of these collections of information, including suggestions for reducing burden, to the Federal Energy Regulatory Commission, 888 First Street NE, Washington, DC 20426 (Attention: Information Clearance Officer); and to the Office of Information and Regulatory Affairs, Office of Management and Budget, Washington, DC 20503 (Attention: Desk Officer for the Federal Energy Regulatory Commission). No person shall be subject to any penalty if any collection of information does not display a valid control number (44 U.S.C. § 3512 (a)).

## GENERAL INSTRUCTIONS

Prepare this report in conformity with the Uniform System of Accounts (18 CFR Part 101) (USofA). Interpret all accounting words and phrases in accordance with the USofA.

Enter in whole numbers (dollars or MWH) only, except where otherwise noted. (Enter cents for averages and figures per unit where cents are important. The truncating of cents is allowed except on the four basic financial statements where rounding is required.) The amounts shown on all supporting pages must agree with the amounts entered on the statements that they support. When applying thresholds to determine significance for reporting purposes, use for balance sheet accounts the balances at the end of the current reporting period, and use for statement of income accounts the current year's year to date amounts.

Complete each question fully and accurately, even if it has been answered in a previous report. Enter the word "None" where it truly and completely states the fact.



such persons specific answers to all questions upon which the Commission may need information. The Commission may require that such reports shall include, among other things, full information as to assets and Liabilities, capitalization, net investment, and reduction thereof, gross receipts, interest due and paid, depreciation, and other reserves, cost of project and other facilities, cost of maintenance and operation of the project and other facilities, cost of renewals and replacement of the project works and other facilities, depreciation, generation, transmission, distribution, delivery, use, and sale of electric energy. The Commission may require any such person to make adequate provision for currently determining such costs and other facts. Such reports shall be made under oath unless the Commission otherwise specifies*.10

"Sec. 309.

The Commission shall have power to perform any and all acts, and to prescribe, issue, make, and rescind such orders, rules and regulations as it may find necessary or appropriate to carry out the provisions of this Act. Among other things, such rules and regulations may define accounting, technical, and trade terms used in this Act; and may prescribe the FERC Form or FERC Forms of all statements, declarations, applications, and reports to be filed with the Commission, the information which they shall contain, and the time within which they shall be field..."

## GENERAL PENALTIES

The Commission may assess up to $1 million per day per violation of its rules and regulations. See FPA § 316(a) (2005), 16 U.S.C. § 825o(a).

**FERC FORM NO. 1**
**REPORT OF MAJOR ELECTRIC UTILITIES, LICENSEES AND OTHER**

**IDENTIFICATION**

| 01 Exact Legal Name of Respondent | 02 Year/ Period of Report |
|---|---|
| PacifiCorp | End of: 2024/ Q4 |

| 03 Previous Name and Date of Change (If name changed during year) |
|---|
| / |

| 04 Address of Principal Office at End of Period (Street, City, State, Zip Code) |
|---|
| 825 N.E. Multnomah Street, Suite 1900, Portland, OR 97232 |

| 05 Name of Contact Person | 06 Title of Contact Person |
|---|---|
| Jennifer Kahl | External Reporting Director |

| 07 Address of Contact Person (Street, City, State, Zip Code) |
|---|
| 825 N.E. Multnomah Street, Suite 1900, Portland, OR 97232 |

| 08 Telephone of Contact Person, Including Area Code | 09 This Report is An Original / A Resubmission | 10 Date of Report (Mo, Da, Yr) |
|---|---|---|
| (503) 813-5784 | (1) ☑ An Original<br>(2) ☐ A Resubmission | 04/15/2025 |

**Annual Corporate Officer Certification**

The undersigned officer certifies that:

I have examined this report and to the best of my knowledge, information, and belief all statements of fact contained in this report are correct statements of the business affairs of the respondent and the financial statements, and other financial information contained in this report, conform in all material respects to the Uniform System of Accounts.

| 01 Name | 03 Signature | 04 Date Signed (Mo, Da, Yr) |
|---|---|---|
| Nikki L. Kobliha | /s/ Nikki L. Kobliha | 04/15/2025 |
| 02 Title | | |
| Senior Vice President and Chief Financial Officer | | |

Title 18, U.S.C. 1001 makes it a crime for any person to knowingly and willingly to make to any Agency or Department of the United States any false, fictitious or fraudulent statements as to any matter within its jurisdiction.

| Name of Respondent: PacifiCorp | This report is: (1) ☑ An Original (2) ☐ A Resubmission | Date of Report: 04/15/2025 | Year/Period of Report End of: 2024/ Q4 |
|---|---|---|---|

**LIST OF SCHEDULES (Electric Utility)**

Enter in column (c) the terms "none," "not applicable," or "NA," as appropriate, where no information or amounts have been reported for certain pages. Omit pages where the respondents are "none," "not applicable," or "NA".


| Line No. | Title of Schedule (a) | Reference Page No. (b) | Remarks (c) |
|---|---|---|---|
| | Identification | 1 | |
| | List of Schedules | 2 | |
| 1 | General Information | 101 | |
| 2 | Control Over Respondent | 102 | |
| 3 | Corporations Controlled by Respondent | 103 | |
| 4 | Officers | 104 | |
| 5 | Directors | 105 | |
| 6 | Information on Formula Rates | 106 | |
| 7 | Important Changes During the Year | 108 | |
| 8 | Comparative Balance Sheet | 110 | |
| 9 | Statement of Income for the Year | 114 | |
| 10 | Statement of Retained Earnings for the Year | 118 | |
| 12 | Statement of Cash Flows | 120 | |
| 12 | Notes to Financial Statements | 122 | |
| 13 | Statement of Accum Other Comp Income, Comp Income, and Hedging Activities | 122a | |
| 14 | Summary of Utility Plant & Accumulated Provisions for Dep, Amort & Dep | 200 | |
| 15 | Nuclear Fuel Materials | 202 | N/A |
| 16 | Electric Plant in Service | 204 | |
| 17 | Electric Plant Leased to Others | 213 | N/A |
| 18 | Electric Plant Held for Future Use | 214 | |
| 19 | Construction Work in Progress-Electric | 216 | |
| 20 | Accumulated Provision for Depreciation of Electric Utility Plant | 219 | |
| 21 | Investment of Subsidiary Companies | 224 | |
| 22 | Materials and Supplies | 227 | |
| 23 | Allowances | 228 | |
| 24 | Extraordinary Property Losses | 230a | N/A |
| 25 | Unrecovered Plant and Regulatory Study Costs | 230b | N/A |
| 26 | Transmission Service and Generation Interconnection Study Costs | 231 | |
| 27 | Other Regulatory Assets | 232 | |
| 28 | Miscellaneous Deferred Debits | 233 | |
| 29 | Accumulated Deferred Income Taxes | 234 | |
| 30 | Capital Stock | 250 | |
| 31 | Other Paid-in Capital | 253 | |
| 32 | Capital Stock Expense | 254b | |
| 33 | Long-Term Debt | 256 | |
| 34 | Reconciliation of Reported Net Income with Taxable Inc for Fed Inc Tax | 261 | |
| 35 | Taxes Accrued, Prepaid and Charged During the Year | 262 | |
| 36 | Accumulated Deferred Investment Tax Credits | 266 | |
| 37 | Other Deferred Credits | 269 | |
| 38 | Accumulated Deferred Income Taxes-Accelerated Amortization Property | 272 | |
| 39 | Accumulated Deferred Income Taxes-Other Property | 274 | |

| | | | |
|---|---|---|---|
| 40 | Accumulated Deferred Income Taxes-Other | 276 | |
| 41 | Other Regulatory Liabilities | 278 | |
| 42 | Electric Operating Revenues | 300 | |
| 43 | Regional Transmission Service Revenues (Account 457.1) | 302 | N/A |
| 44 | Sales of Electricity by Rate Schedules | 304 | |
| 45 | Sales for Resale | 310 | |
| 46 | Electric Operation and Maintenance Expenses | 320 | |
| 47 | Purchased Power | 326 | |
| 48 | Transmission of Electricity for Others | 328 | |
| 49 | Transmission of Electricity by ISO/RTOs | 331 | N/A |
| 50 | Transmission of Electricity by Others | 332 | |
| 51 | Miscellaneous General Expenses-Electric | 335 | |
| 52 | Depreciation and Amortization of Electric Plant (Account 403, 404, 405) | 336 | |
| 53 | Regulatory Commission Expenses | 350 | |
| 54 | Research, Development and Demonstration Activities | 352 | N/A |
| 55 | Distribution of Salaries and Wages | 354 | |
| 56 | Common Utility Plant and Expenses | 356 | N/A |
| 57 | Amounts included in ISO/RTO Settlement Statements | 397 | |
| 58 | Purchase and Sale of Ancillary Services | 398 | |
| 59 | Monthly Transmission System Peak Load | 400 | |
| 60 | Monthly ISO/RTO Transmission System Peak Load | 400a | N/A |
| 61 | Electric Energy Account | 401a | |
| 62 | Monthly Peaks and Output | 401b | |
| 63 | Steam Electric Generating Plant Statistics | 402 | |
| 64 | Hydroelectric Generating Plant Statistics | 406 | |
| 65 | Pumped Storage Generating Plant Statistics | 408 | N/A |
| 66 | Generating Plant Statistics Pages | 410 | |
| 66.1 | Energy Storage Operations (Large Plants) | 414 | N/A |
| 66.2 | Energy Storage Operations (Small Plants) | 419 | N/A |
| 67 | Transmission Line Statistics Pages | 422 | |
| 68 | Transmission Lines Added During Year | 424 | |
| 69 | Substations | 426 | |
| 70 | Transactions with Associated (Affiliated) Companies | 429 | |
| 71 | Footnote Data | 450 | |
| | Stockholders' Reports (check appropriate box) | | |
| | Stockholders' Reports Check appropriate box:<br><br>☑ Two copies will be submitted<br>☐ No annual report to stockholders is prepared | | |

| Name of Respondent:<br>PacifiCorp | This report is:<br>(1) ☑ An Original<br>(2) ☐ A Resubmission | Date of Report:<br>04/15/2025 | Year/Period of Report<br>End of: 2024/ Q4 |
|---|---|---|---|

**GENERAL INFORMATION**

1. Provide name and title of officer having custody of the general corporate books of account and address of office where the general corporate books are kept, and address of office where any other corporate books of account are kept, if different from that where the general corporate books are kept.

Nikki L. Kobliha

Senior Vice President and Chief Financial Officer

825 N.E. Multnomah Street, Suite 1900, Portland, OR 97232

2. Provide the name of the State under the laws of which respondent is incorporated, and date of incorporation. If incorporated under a special law, give reference to such law. If not incorporated, state that fact and give the type of organization and the date organized.

PacifiCorp was initially incorporated in 1910 under the laws of the state of Maine under the name Pacific Power & Light Company. In 1984, Pacific Power & Light Company changed its name to PacifiCorp. In 1989, it merged with Utah Power and Light Company, a Utah corporation, in a transaction wherein both corporations merged into a newly formed Oregon corporation. The resulting Oregon corporation was re-named PacifiCorp, which is the operating entity today.

State of Incorporation:

Date of Incorporation:

Incorporated Under Special Law:

3. If at any time during the year the property of respondent was held by a receiver or trustee, give (a) name of receiver or trustee, (b) date such receiver or trustee took possession, (c) the authority by which the receivership or trusteeship was created, and (d) date when possession by receiver or trustee ceased.

Not applicable.

(a) Name of Receiver or Trustee Holding Property of the Respondent:

(b) Date Receiver took Possession of Respondent Property:

(c) Authority by which the Receivership or Trusteeship was created:

(d) Date when possession by receiver or trustee ceased:

4. State the classes or utility and other services furnished by respondent during the year in each State in which the respondent operated.

PacifiCorp is a United States regulated electric utility company headquartered in Oregon that serves approximately 2.1 million retail electric customers, including residential, commercial, industrial, irrigation and other customers in portions of Utah, Oregon, Wyoming, Washington, Idaho and California. PacifiCorp is principally engaged in the business of generating, transmitting, distributing and selling electricity. In addition to retail sales, PacifiCorp buys and sells electricity on the wholesale market with other utilities, energy marketing companies, financial institutions and other market participants. PacifiCorp delivers electricity to customers in Utah, Wyoming and Idaho under the trade name Rocky Mountain Power and to customers in Oregon, Washington and California under the trade name Pacific Power.

5. Have you engaged as the principal accountant to audit your financial statements an accountant who is not the principal accountant for your previous year's certified financial statements?

(1) ☐ Yes

(2) ☑ No

| Name of Respondent:<br>PacifiCorp | This report is:<br>(1) ☑ An Original<br>(2) ☐ A Resubmission | Date of Report:<br>04/15/2025 | Year/Period of Report<br>End of: 2024/ Q4 |
|---|---|---|---|

**CONTROL OVER RESPONDENT**

1. If any corporation, business trust, or similar organization or a combination of such organizations jointly held control over the respondent at the end of the year, state name of controlling corporation or organization, manner in which control was held, and extent of control. If control was in a holding company organization, show the chain of ownership or control to the main parent company or organization. If control was held by a trustee(s), state name of trustee(s), name of beneficiary or beneficiaries for whom trust was maintained, and purpose of the trust.

Berkshire Hathaway Inc.
Berkshire Hathaway Energy Company ("BHE") (wholly owned by Berkshire Hathaway, Inc.)
PPW Holdings LLC (wholly owned by BHE)
PacifiCorp (wholly owned by PPW Holdings LLC)

**NOTES TO FINANCIAL STATEMENTS**

1. Use the space below for important notes regarding the Balance Sheet, Statement of Income for the year, Statement of Retained Earnings for the year, and Statement of Cash Flows, or any account thereof. Classify the notes according to each basic statement, providing a subheading for each statement except where a note is applicable to more than one statement.
2. Furnish particulars (details) as to any significant contingent assets or liabilities existing at end of year, including a brief explanation of any action initiated by the Internal Revenue Service involving possible assessment of additional income taxes of material amount, or of a claim for refund of income taxes of a material amount initiated by the utility. Give also a brief explanation of any dividends in arrears on cumulative preferred stock.
3. For Account 116, Utility Plant Adjustments, explain the origin of such amount, debits and credits during the year, and plan of disposition contemplated, giving references to Commission orders or other authorizations respecting classification of amounts as plant adjustments and requirements as to disposition thereof.
4. Where Accounts 189, Unamortized Loss on Reacquired Debt, and 257, Unamortized Gain on Reacquired Debt, are not used, give an explanation, providing the rate treatment given these items. See General Instruction 17 of the Uniform System of Accounts.
5. Give a concise explanation of any retained earnings restrictions and state the amount of retained earnings affected by such restrictions.
6. If the notes to financial statements relating to the respondent company appearing in the annual report to the stockholders are applicable and furnish the data required by instructions above and on pages 114-121, such notes may be included herein.
7. For the 3Q disclosures, respondent must provide in the notes sufficient disclosures so as to make the interim information not misleading. Disclosures which would substantially duplicate the disclosures contained in the most recent FERC Annual Report may be omitted.
8. For the 3Q disclosures, the disclosures shall be provided where events subsequent to the end of the most recent year have occurred which have a material effect on the respondent. Respondent must include in the notes significant changes since the most recently completed year in such items as: accounting principles and practices; estimates inherent in the preparation of the financial statements; status of long-term contracts; capitalization including significant new borrowings or modifications of existing financing agreements; and changes resulting from business combinations or dispositions. However were material contingencies exist, the disclosure of such matters shall be provided even though a significant change since year end may not have occurred.
9. Finally, if the notes to the financial statements relating to the respondent appearing in the annual report to the stockholders are applicable and furnish the data required by the above instructions, such notes may be included herein.

**PACIFICORP**
**NOTES TO FINANCIAL STATEMENTS**

**(1) Organization and Operations**

PacifiCorp is a United States ("U.S.") regulated electric utility company serving retail customers, including residential, commercial, industrial, irrigation and other customers in portions of Utah, Oregon, Wyoming, Washington, Idaho and California. PacifiCorp owns, or has interests in, a number of thermal, hydroelectric, wind-powered and geothermal generating facilities, as well as electric transmission and distribution assets. PacifiCorp also buys and sells electricity on the wholesale market with other utilities, energy marketing companies, financial institutions and other market participants. PacifiCorp is subject to comprehensive state and federal regulation. PacifiCorp is an indirect subsidiary of Berkshire Hathaway Energy Company ("BHE"), a holding company based in Des Moines, Iowa that has investments in subsidiaries principally engaged in energy businesses. BHE is a wholly owned subsidiary of Berkshire Hathaway Inc. ("Berkshire Hathaway").

**(2) Summary of Significant Accounting Policies**

*Basis of Presentation*

These financial statements are prepared in accordance with the requirements of the Federal Energy Regulatory Commission ("FERC") as set forth in its applicable Uniform System of Accounts and published accounting releases, which is a comprehensive basis of accounting other than accounting principles generally accepted in the United States of America ("GAAP"). These notes include certain applicable disclosures required by GAAP adjusted to the FERC basis of presentation and include specific information requested by the FERC.

The following are the significant differences between the FERC accounting and reporting standards and GAAP.

*Investments in Subsidiaries*

In accordance with FERC Order No. AC11-132, PacifiCorp accounts for its investment in subsidiaries using the equity method for FERC reporting purposes rather than consolidating the assets, liabilities, revenues and expenses of subsidiaries as required by GAAP. GAAP requires that entities in which a company holds a controlling financial interest be consolidated. Also in accordance with FERC Order No. AC11-132, PacifiCorp does not eliminate intercompany profit on transactions with equity investees as would be required under GAAP. The accounting treatment described above has no effect on net income or the combined retained earnings of PacifiCorp and undistributed earnings of subsidiaries.

*Costs of Removal*

Estimated removal costs that are recovered through approved depreciation rates, but that do not meet the requirements of a legal asset retirement obligation ("ARO") are reflected in the cost of removal regulatory liability under GAAP and as accumulated provision for depreciation under the FERC accounting and reporting standards.

*Income Taxes*

Accumulated deferred income taxes are classified as net non-current assets or liabilities on the balance sheet for GAAP. Under the FERC accounting and reporting standards, accumulated deferred income taxes are classified as gross non-current assets and gross non-current liabilities. Additionally, there are certain presentational differences between FERC and GAAP for amounts related to unrecognized tax benefits associated with temporary differences in accordance with FERC guidance. For GAAP, unrecognized tax benefits associated with temporary differences are reflected as other liabilities while for FERC the income tax impact of uncertain tax positions associated with temporary differences are reflected in accumulated deferred income taxes.

Interest and penalties on income taxes for GAAP are classified as income tax expense. All such amounts are classified as interest income, interest expense and penalties under the FERC accounting and reporting standards.

*Pensions and Postretirement Benefits Other Than Pensions*

Pension and postretirement benefits other than pensions ("PBOP") are comprised of several different components of net periodic benefit costs. As required by GAAP, the service cost component is reported with other compensation costs arising from services rendered by employees, while the other components of net periodic benefit costs are presented outside of operating income. Additionally, only the service cost component of net periodic benefit costs is eligible for capitalization under GAAP. In accordance with FERC guidance, PacifiCorp continues to report the components of net periodic benefit costs for pension and PBOP on the statement of income and follows GAAP guidance to capitalize only the service cost component of net periodic benefit costs.

*Reclassifications*

Certain other reclassifications of balance sheet, income statement and cash flow amounts have been made in order to conform to the FERC basis of presentation. These reclassifications had no effect on net income.

*Use of Estimates in Preparation of Financial Statements*

The preparation of the financial statements in conformity with the FERC and GAAP requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities at the date of the financial statements and the reported amounts of revenue and expenses during the period. These estimates include, but are not limited to, the effects of regulation; certain assumptions made in accounting for pension and other postretirement benefits; AROs; income taxes; unbilled revenue; valuation of certain financial assets and liabilities, including derivative contracts; and accounting for loss contingencies and applicable insurance recoveries, including those related to the Oregon and Northern California 2020 wildfires (the "2020 Wildfires") and a wildfire that began in the Oak Knoll Ranger District of the Klamath National Forest in Siskiyou County, California in July 2022 (the "2022 McKinney Fire"), referred to together as "the Wildfires" as discussed in Note 14. Actual results may differ from the estimates used in preparing the financial statements.

*Accounting for the Effects of Certain Types of Regulation*

PacifiCorp prepares its financial statements in accordance with authoritative guidance for regulated operations, which recognizes the economic effects of regulation. Accordingly, PacifiCorp defers the recognition of certain costs or income if it is probable that, through the ratemaking process, there will be a corresponding increase or decrease in future rates. Regulatory assets and liabilities are established to reflect the impacts of these deferrals, which will be recognized in earnings in the periods the corresponding changes in rates occur.

If it becomes no longer probable that the deferred costs or income will be included in future rates, the related regulatory assets and liabilities will be recognized in net income, returned to customers or re-established as accumulated other comprehensive income (loss) ("AOCI").

*Fair Value Measurements*

Fair value is the price that would be received to sell an asset or paid to transfer a liability between market participants in the principal market or in the most advantageous market when no principal market exists. Adjustments to transaction prices or quoted market prices may be required in illiquid or disorderly markets in order to estimate fair value. Different valuation techniques may be appropriate under the circumstances to determine the value that would be received to sell an asset or paid to transfer a liability in an orderly transaction. Market participants are assumed to be independent, knowledgeable, able and willing to transact an exchange and not under duress. Nonperformance or credit risk is considered when determining fair value. Considerable judgment may be required in interpreting market data used to develop the estimates of fair value. Accordingly, estimates of fair value presented herein are not necessarily indicative of the amounts that could be realized in a current or future market exchange.

*Cash Equivalents and Restricted Cash and Cash Equivalents*

Cash equivalents consist of funds invested in money market mutual funds, U.S. Treasury Bills and other investments with a maturity of three months or less when purchased. Cash and cash equivalents exclude amounts where availability is restricted by legal requirements, loan agreements or other contractual provisions. Restricted cash and cash equivalents included in other special funds consist substantially of funds representing vendor retention, nuclear decommissioning and custodial funds. A reconciliation of cash and cash equivalents and restricted cash equivalents as of December 31, 2024 and 2023 as presented on the Statements of Cash Flows is outlined below and disaggregated by the line items in which they appear on the Comparative Balance Sheets (in millions):

| | 2024 | 2023 |
|---|---|---|
| Cash (131) | $ 20 | $ 14 |
| Other special funds (128) | 16 | 53 |
| Temporary cash investments (136) | 21 | 114 |
| Total cash and cash equivalents and restricted cash and cash equivalents | 57 | 181 |

*Investments*

Available-for-sale securities are carried at fair value with realized gains and losses, as determined on a specific identification basis, recognized in earnings and unrealized gains and losses recognized in AOCI, net of tax. As of December 31, 2024 and 2023, PacifiCorp had no unrealized gains and losses on available-for-sale securities. Trading securities are carried at fair value with realized and unrealized gains and losses recognized in earnings.

*Allowance for Credit Losses*

Trade receivables are primarily short-term in nature with stated collection terms of less than one year from the date of origination, and are stated at the outstanding principal amount, net of an estimated allowance for credit losses. The allowance for credit losses is based on PacifiCorp's assessment of the collectability of amounts owed to PacifiCorp by its customers. This assessment requires judgment regarding the ability of customers to pay or the outcome of any pending disputes. In measuring the allowance for credit losses for trade receivables, PacifiCorp primarily utilizes credit loss history. However, PacifiCorp may adjust the allowance for credit losses to reflect current conditions and reasonable and supportable forecasts that deviate from historical experience. The changes in the balance of the allowance for credit losses, which is included in accumulated provision for uncollectible accounts on the Comparative Balance Sheet, is summarized as follows for the years ended December 31 (in millions):

| | 2024 | 2023 |
|---|---|---|
| Beginning balance | $ 30 | $ 19 |
| Charged to operating costs and expenses, net | 26 | 34 |
| Write-offs, net | (34) | (23) |
| Ending balance | $ 22 | $ 30 |

*Derivatives*

PacifiCorp employs a number of different derivative contracts, which may include forwards, options, swaps and other agreements, to manage price risk for electricity, natural gas and other commodities and interest rate risk. Derivative contracts are recorded on the Comparative Balance Sheet as either assets or liabilities and are stated at estimated fair value unless they are designated as normal purchases or normal sales and qualify for the exception afforded by GAAP. Derivative balances reflect offsetting permitted under master netting agreements with counterparties and cash collateral paid or received under such agreements.

Commodity derivatives used in normal business operations that are settled by physical delivery, among other criteria, are eligible for and may be designated as normal purchases or normal sales. Normal purchases or normal sales contracts are not marked-to-market and settled amounts are recognized as operating revenue or operations expenses on the Statement of Income.

For PacifiCorp's derivative contracts, the settled amount is generally included in rates. Accordingly, the net unrealized gains and losses associated with interim price movements on contracts that are accounted for as derivatives and probable of inclusion in rates are recorded as regulatory liabilities or assets. For a derivative contract not probable of inclusion in rates, changes in the fair value are recognized in earnings.

*Inventories*

Inventories consist mainly of materials, supplies and fuel stocks and are stated at the lower of average cost or net realizable value.

*Net Utility Plant*

*General*

Additions to utility plant are recorded at cost. PacifiCorp capitalizes all construction-related material, direct labor and contract services, as well as indirect construction costs, which include debt and equity allowance for funds used during construction ("AFUDC"). The cost of additions and betterments are capitalized, while costs incurred that do not improve or extend the useful lives of the related assets are generally expensed.

Depreciation and amortization are generally computed on the straight-line method based on composite asset class lives prescribed by PacifiCorp's various regulatory authorities or over the assets' estimated useful lives. Depreciation studies are completed periodically to determine the appropriate composite asset class lives, net salvage and depreciation rates. These studies are reviewed and rates are ultimately approved by the various regulatory authorities. Net salvage includes the estimated future residual values of the assets and any estimated removal costs recovered through approved depreciation rates. Estimated removal costs are recorded as either accumulated provision for depreciation or an ARO liability on the Comparative Balance Sheet, depending on whether the obligation meets the requirements of an ARO. As actual removal costs are incurred, the associated accumulated provision for depreciation or ARO liability is reduced.

Generally when PacifiCorp retires or sells a component of regulated utility plant, it charges the original cost, net of any proceeds from the disposition, to accumulated provision for depreciation. Any gain or loss on disposals of all other assets is recorded through earnings.

Debt and equity AFUDC, which represents the estimated costs of debt and equity funds necessary to finance the construction of utility plant is capitalized as a component of utility plant, with offsetting credits to the Statement of Income. AFUDC is computed based on guidelines set forth by the FERC. After construction is completed, PacifiCorp is permitted to earn a return on these costs as a component of the related assets, as well as recover these costs through depreciation expense over the useful lives of the related assets.

*Asset Retirement Obligations*

PacifiCorp recognizes AROs when it has a legal obligation to perform decommissioning, reclamation or removal activities upon retirement of an asset. PacifiCorp's AROs are primarily associated with its generating facilities. The fair value of an ARO liability is recognized in the period in which it is incurred, if a reasonable estimate of fair value can be made, and is added to the carrying amount of the associated asset, which is then depreciated over the remaining useful life of the asset. Subsequent to the initial recognition, the ARO liability is adjusted for any revisions to the original estimate of undiscounted cash flows (with corresponding adjustments to utility plant, net) and for accretion of the ARO liability due to the passage of time. The difference between the ARO liability, the corresponding ARO asset included in utility plant and amounts recovered in rates to satisfy such liabilities is recorded as a regulatory asset or liability.

*Impairment*

PacifiCorp evaluates long-lived assets for impairment, including utility plant, when events or changes in circumstances indicate that the carrying value of such assets may not be recoverable or when the assets are being held for sale. Upon the occurrence of a triggering event, the asset is reviewed to assess whether the estimated undiscounted cash flows expected from the use of the asset plus the residual value from the ultimate disposal exceeds the carrying value of the asset. If the carrying value exceeds the estimated recoverable amounts, the appropriate FERC accounts are adjusted to write down the asset to the estimated fair value and any resulting impairment loss is reflected on the Statement of Income. The impacts of regulation are considered when evaluating the carrying value of regulated assets.

*Leases*

PacifiCorp has non-cancelable operating leases primarily for land, office space, office equipment, and generating facilities and finance leases consisting primarily of office buildings, natural gas pipeline facilities, and vehicles. These leases generally require PacifiCorp to pay for insurance, taxes and maintenance applicable to the leased property. Given the capital intensive nature of the utility industry, it is common for a portion of lease costs to be capitalized when used during construction or maintenance of assets, in which the associated costs will be capitalized with the corresponding asset and depreciated over the remaining life of that asset. Certain leases contain renewal options for varying periods and escalation clauses for adjusting rent to reflect changes in price indices. PacifiCorp does not include options in its lease calculations unless there is a triggering event indicating PacifiCorp is reasonably certain to exercise the option. PacifiCorp's accounting policy is to not recognize right-of-use assets and lease obligations for leases with contract terms of one year or less and not separate lease components from non-lease components and instead account for each separate lease component and the non-lease components associated with a lease as a single lease component. Right-of-use assets will be evaluated for impairment in line with GAAP when a triggering event has occurred that might affect the value and use of the assets being leased.

PacifiCorp's leases of generating facilities generally are in the form of long-term purchases of electricity, also known as power purchase agreements ("PPA"). PPAs are generally signed before or during the early stages of project construction and can yield a lease that has not yet commenced. These agreements are primarily for renewable energy and the payments are considered variable lease payments as they are based on the amount of output.

PacifiCorp follows FERC accounting and reporting requirements and records operating and finance right-of-use assets in Account 101.1, Property under capital leases, and the current and noncurrent operating and finance lease liabilities in Account 243, Obligations under capital leases – Current and Account 227, Obligations under capital leases – Noncurrent, respectively.

*Revenue Recognition*

PacifiCorp uses a single five-step model to identify and recognize revenue from contracts with customers ("Customer Revenue") upon transfer of control of promised goods or services in an amount that reflects the consideration to which PacifiCorp expects to be entitled in exchange for those goods or services. PacifiCorp records sales, franchise and excise taxes collected directly from customers and remitted directly to the taxing authorities on a net basis on the Statement of Income.

Substantially all of PacifiCorp's Customer Revenue is derived from tariff-based sales arrangements approved by various regulatory commissions. These tariff-based revenues are mainly comprised of energy, transmission and distribution and have performance obligations to deliver energy products and services to customers which are satisfied over time as energy is delivered or services are provided.

Revenue recognized is equal to what PacifiCorp has the right to invoice as it corresponds directly with the value to the customer of PacifiCorp's performance to date and includes billed and unbilled amounts. Payments for amounts billed are generally due from the customer within 30 days of billing. Rates charged for energy products and services are established by regulators or contractual arrangements that establish the transaction price as well as the allocation of price amongst the separate performance obligations. When preliminary regulated rates are permitted to be billed prior to final approval by the applicable regulator, certain revenue collected may be subject to refund and classified in accordance with FERC accounting standards.

The determination of customer billings is based on a systematic reading of meters. At the end of each month, energy provided to customers since the date of the last meter reading is estimated, and the corresponding unbilled revenue is recorded. Factors that can impact the estimate of unbilled energy include, but are not limited to, seasonal weather patterns, total volumes supplied to the system, line losses, economic impacts and composition of sales among customer classes. Unbilled revenue is reversed in the following month and billed revenue is recorded based on the subsequent meter readings.

*Unamortized Debt, Premiums, Discounts and Debt Issuance Costs*

Premiums, discounts and debt issuance costs incurred for the issuance of long-term debt are amortized over the term of the related financing using the effective interest method.

*Income Taxes*

Berkshire Hathaway includes PacifiCorp in its U.S. federal income tax return. Consistent with established regulatory practice, PacifiCorp's provision for income taxes has been computed on a stand-alone basis.

Deferred income tax assets and liabilities are based on differences between the financial statement and income tax basis of assets and liabilities using enacted income tax rates expected to be in effect for the year in which the differences are expected to reverse. Changes in deferred income tax assets and liabilities associated with components of other comprehensive income ("OCI") are charged or credited directly to OCI. Changes in deferred income tax assets and liabilities associated with certain property-related basis differences and other various differences that PacifiCorp deems probable to be passed on to its customers in most state jurisdictions are charged or credited directly to a regulatory asset or liability and will be included in regulated rates when the temporary differences reverse or as otherwise approved by PacifiCorp's various regulatory commissions. Other changes in deferred income tax assets and liabilities are included as a component of income tax expense. Changes in deferred income tax assets and liabilities attributable to changes in enacted income tax rates are charged or credited to income tax expense or a regulatory asset or liability in the period of enactment. Valuation allowances are established when necessary to reduce deferred income tax assets to the amount that is more-likely-than-not to be realized.

Investment tax credits are deferred and amortized over the estimated useful lives of the related properties or as prescribed by various regulatory commissions.

PacifiCorp recognizes the tax benefit from an uncertain tax position only if it is more-likely-than-not that the tax position will be sustained on examination by the taxing authorities, based on the technical merits of the position. The tax benefits recognized in the financial statements from such a position are measured based on the largest benefit that is more-likely-than-not to be realized upon ultimate settlement.

*Government Grants*

From time to time, PacifiCorp enters into grant agreements with federal agencies, as well as agreements with third parties as a subrecipient of a federal grant, subjecting PacifiCorp to various federal compliance requirements. Most commonly these are cost share grants where PacifiCorp expenditures match the amount of grant proceeds. Grant proceeds most frequently support capital projects but are also used to cover operating costs. Grant proceeds received to reimburse capital project costs are applied as a direct offset to construction work-in-progress, ultimately serving to reduce PacifiCorp's investment in net utility plant. Grant proceeds received to reimburse operating costs are applied as an offset to operation expense.

*Segment Information*

PacifiCorp currently has one reportable segment, its regulated electric utility operations, which derives its revenue from regulated retail sales of electricity to residential, commercial, industrial and irrigation customers and from wholesale sales. PacifiCorp's chief operating decision maker ("CODM") is its Chief Executive Officer. The CODM uses net income, as reported on the Consolidated Statements of Operations in PacifiCorp's GAAP financial statements that are filed with the U.S. Securities and Exchange Commission ("Consolidated Statements of Operations"), and generally considers actual results versus historical results, budgets or forecasts, as well as unique risks and opportunities, when making decisions about the allocation of resources and capital. The segment expenses regularly provided to the CODM align with the captions presented on the Consolidated Statements of Operations. PacifiCorp's segment capital expenditures are reported on the Statement of Cash Flows as cash outflows for plant. PacifiCorp's segment assets are reported on the Comparative Balance Sheet as total assets.

*New Accounting Pronouncements*

In November 2023, the Financial Accounting Standards Board ("FASB") issued Accounting Standards Update ("ASU") No. 2023-07, Segment Reporting Topic 280, "Segment Reporting—Improvements to Reportable Segment Disclosures" which allows disclosure of one or more measures of segment profit or loss used by the chief operating decision maker to allocate resources and assess performance. Additionally, the standard requires enhanced disclosures of significant segment expenses and other segment items as well as incremental qualitative disclosures on both an annual and interim basis. This guidance is effective for annual reporting periods beginning after December 15, 2023, and interim reporting periods after December 15, 2024. Early adoption is permitted and retrospective application is required for all periods presented. PacifiCorp adopted this guidance for the fiscal year beginning January 1, 2024 under the retrospective method. The adoption did not have a material impact on PacifiCorp's financial statements and disclosures included within Notes to Financial Statements.

In December 2023, the FASB issued ASU No. 2023-09, Income Taxes Topic 740, "Income Tax—Improvements to Income Tax Disclosures" which requires enhanced disclosures, including specific categories and disaggregation of information in the effective tax rate reconciliation, disaggregated information related to income taxes paid, income or loss from continuing operations before income tax expense or benefit, and income tax expense or benefit from continuing operations. This guidance is effective for annual reporting periods beginning after December 15, 2024. Early adoption is permitted and should be applied on a prospective basis, however retrospective application is permitted. PacifiCorp is currently evaluating the impact of adopting this guidance on its financial statements and disclosures included within Notes to Financial Statements.

In November 2024, the FASB issued ASU No. 2024-03, Income Statement—Reporting Comprehensive Income—Expense Disaggregation Disclosures Subtopic 220-40, "Disaggregation of Income Statement Expenses" which addresses requests from investors for more detailed information about certain expenses and requires disclosure of the amounts of purchases of inventory, employee compensation, depreciation and intangible asset amortization included in each relevant expense caption presented on the income statement. This guidance is effective for annual reporting periods beginning after December 15, 2026 and interim reporting periods beginning after December 15, 2027. Early adoption is permitted and should be applied on a prospective basis, however retrospective application is permitted. PacifiCorp is currently evaluating the impact of adopting this guidance on its financial statements and disclosures included within Notes to Financial Statements.

*Subsequent Events*

PacifiCorp has evaluated the impact on its financial statements of events occurring after December 31, 2024 up to February 21, 2025, the date that PacifiCorp's GAAP financial statements were filed with the U.S. Securities and Exchange Commission and has updated such evaluation for disclosure purposes through April 15, 2025. These financial statements include all necessary adjustments and disclosures resulting from these evaluations.

## (3) Net Utility Plant

The average depreciation and amortization rate applied to depreciable utility plant was 3.2% and 3.4% for the years ended December 31, 2024 and 2023, respectively, including the impacts of $29 million and $29 million in 2024 and 2023, respectively, primarily related to Idaho's, Utah's, Wyoming's and Washington's shares of incremental decommissioning costs for certain coal-fueled units.

*Government Grants*

In November 2024, PacifiCorp accepted two cost share grants from the U.S. Department of Energy ("DOE") under the DOE's Grid Resilience and Innovation Partnerships ("GRIP") Program supported by the Infrastructure Investment and Jobs Act. The two GRIP grants will provide cash proceeds totaling approximately $150 million as cost reimbursements supporting PacifiCorp's investment in certain wildfire mitigation projects, such as system hardening for fire resistance and prevention and new substation infrastructure, and other investments in technologies that significantly enhance situational awareness to reduce or mitigate wildfires and improve electric grid flexibility, reliability and resiliency. The period of performance for both GRIP grants begins September 2024 and runs through September 2028 and 2029. No costs incurred after the period of performance will be eligible for reimbursement.

In conjunction with the two GRIP awards, the DOE and U.S. Department of Labor accepted PacifiCorp's request for a temporary exception regarding the Davis-Bacon Act weekly pay and certified payroll reporting requirements with which PacifiCorp is required to comply under the terms of the grants. The parties agreed to a curative plan that provides for a temporary means to achieve the goals of these requirements and allows PacifiCorp to have until April 1, 2026, to fully comply with these requirements.

Other current DOE cost share grants primarily support electric vehicle infrastructure programs and energy efficiency programs. The period of performance for the electric vehicle infrastructure grant ended December 2024, and was for total cash proceeds of $6 million. The period of performance for the energy efficiency grant ends May 2028, and is for total cash proceeds of $5 million.

On January 20, 2025, U.S. federal executive order entitled *Unleashing American Energy* was issued requiring federal agencies to immediately pause disbursement of federal funds appropriated under the Inflation Reduction Act of 2022 and the Infrastructure Investment and Jobs Act, subject to respective agency review within 90 days of the date of the order of the agency's processes, policies and programs for issuing grants consistent with the policies stated in the executive order. PacifiCorp is monitoring federal activities associated with the executive order to determine whether the funding associated with its grants will be impacted.

Various compliance requirements are associated with the DOE grants, including demonstration that the costs are allowable under the grants. In the event PacifiCorp fails to meet these requirements, it could be required to return funds to the DOE.

During the year ended December 31, 2024, approximately $11 million of federal grant funds reduced additions to net utility plant on the Comparative Balance Sheet and approximately $4 million of federal grant funds reduced operation and maintenance expenses on the Statement of Income. Federal grant funds received prior to 2024 were insignificant.

## (4) Jointly Owned Utility Facilities

Under joint facility ownership agreements with other utilities, PacifiCorp, as a tenant in common, has undivided interests in jointly owned generation, transmission and distribution facilities. PacifiCorp accounts for its proportionate share of each facility, and each joint owner has provided financing for its share of each facility. Operating costs of each facility are assigned to joint owners based on their percentage of ownership or energy production, depending on the nature of the cost. Operating costs and expenses on the Statement of Income include PacifiCorp's share of the expenses of these facilities.

The amounts shown in the table below represent PacifiCorp's share in each jointly owned facility included in net utility plant as of December 31, 2024 (dollars in millions):

| | PacifiCorp Share | Facility in Service | Accumulated Depreciation and Amortization | Construction Work-in-Progress |
|---|---|---|---|---|
| Jim Bridger Nos. 1 - 4 | 67% | $ 1,570 | $ 1,030 | $ 4 |
| Hunter No. 1 | 94 | 509 | 256 | 3 |
| Hunter No. 2 | 60 | 315 | 162 | 1 |
| Wyodak | 80 | 492 | 303 | — |
| Colstrip Nos. 3 and 4 | 10 | 263 | 228 | 2 |
| Hermiston | 50 | 191 | 118 | 6 |
| Craig Nos. 1 and 2 | 19 | 373 | 217 | — |
| Hayden No. 1 | 25 | 77 | 58 | — |
| Hayden No. 2 | 13 | 45 | 35 | — |
| Transmission and distribution facilities | Various | 932 | 351 | 308 |
| Total | | $ 4,767 | $ 2,758 | $ 324 |

## (5) Leases

The following table summarizes PacifiCorp's leases recorded on the Comparative Balance Sheet as of December 31 (in millions):

| | 2024 | 2023 |
|---|---|---|
| **Right-of-use assets:** | | |
| Operating leases | $ 11 | $ 12 |
| Finance leases | 24 | 12 |
| Total right-of-use assets | $ 35 | $ 24 |
| **Lease liabilities:** | | |
| Operating leases | $ 11 | $ 12 |
| Finance leases | 24 | 12 |
| Total lease liabilities | $ 35 | $ 24 |

The following table summarizes PacifiCorp's lease costs for the years ended December 31 (in millions):

BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

| | |
|---|---|
| Federal Power Act Section 202(c) | ) |
| Emergency Order: Tri-State | ) |
| Generation and Transmission | ) |
| Association, Platte River Power | ) |
| Authority, Salt River Project, | ) |
| PacifiCorp, and Xcel Energy | ) |

Exhibit to
Motion to Intervene and Request for Rehearing and Stay of
Public Interest Organizations

Exhibit 2-55:
Platte River Power Authority Coal Energy




# Rawhide Energy Station

**Commercial operation:** 1984
**Net capacity:** 280 MW
**Fuel type:** coal
**Operations:** baseload

## Operations

- Platte River's largest single source of system capacity at 280 net megawatts
- Used for baseload energy needs
- Provides approximately half of Platte River's annual delivered energy
- One of the highest-performing coal units in the U.S., averaging 97.28% equivalent availability and 85.08% capacity factor (as of May 31, 2020)
- Reliable fuel supply from Powder River Basin coal reserves in close proximity to plant
- Will be removed from Platte River's energy mix by Dec. 31, 2029

## Financials

- Platte River's lowest operating cost generating resource
- Original debt retired in 2018
- Long-term rail and fuel contracts
- Fuel cost volatility mitigated through flexibility of existing contracts

## Environmental

- Uses state-of-the-art air quality control technology to reduce emissions
- Maintains full compliance with strict environmental laws and regulations

EN

- Healthy bison and waterfowl habitats at Rawhide demonstrate the ability for nature and industry to share space
- Water-efficient design utilizes reclaimed water from a domestic wastewater treatment plant
- No discharge of industrial wastewater from the facility due to beneficial reuse of all process water

# Craig units 1 & 2 (Yampa Project)

**Commercial operation:** Unit 1—1980; Unit 2—1979
**Net capacity:** 151 MW
**Fuel type:** coal
**Operations:** baseload

## Operations

- Platte River's ownership of Craig units 1 and 2 is 18%
- Operated by Tri-State Generation and Transmission
- Co-owners include Tri-State Generation and Transmission, Salt River Project, PacifiCorp and Xcel Energy
- Craig Unit 1 to be removed from Platte River's mix by Dec. 31, 2025
- Craig Unit 2 to be removed from Platte River's mix by Sept. 30, 2028

## Financials

- Platte River's second-lowest operating cost resource
- Fuel prices are based on production costs and not subject to market price volatility
- No debt service
- Fuel cost volatility mitigated by management of mine production levels and costs through an ownership share of Trapper Mine (27.14%), located adjacent to Craig units 1 and 2

## Environmental

- Upgraded technology to reduce sulfur and particulate emissions
- Maintains full compliance with strict environmental laws and regulations

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View all generation resources

**Accessibility Notice:**
Per the Americans with Disabilities Act (ADA), Platte River Power Authority will provide reasonable accommodation to qualified individuals with a disability who need assistance. Please email us at communications@prpa.org or call 970-226-4000. "Walk-in" requests for auxiliary aids and services may be honored to the extent possible but can be unavailable if advance notice is not provided.

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For any accessibility requests, please call 970-226-4000.



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BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

| | |
|---|---|
| Federal Power Act Section 202(c) | ) |
| Emergency Order: Tri-State | ) |
| Generation and Transmission | ) |
| Association, Platte River Power | ) |
| Authority, Salt River Project, | ) |
| PacifiCorp, and Xcel Energy | ) |

Exhibit to
Motion to Intervene and Request for Rehearing and Stay of
Public Interest Organizations

Exhibit 2-56:
Xcel FERC Form 1

| THIS FILING IS |
| --- |
| Item 1: ☑ An Initial (Original) Submission OR ☐ Resubmission No. |

# FERC FINANCIAL REPORT
# FERC FORM No. 1: Annual Report of Major Electric Utilities, Licensees and Others and Supplemental Form 3-Q: Quarterly Financial Report

These reports are mandatory under the Federal Power Act, Sections 3, 4(a), 304 and 309, and 18 CFR 141.1 and 141.400. Failure to report may result in criminal fines, civil penalties and other sanctions as provided by law. The Federal Energy Regulatory Commission does not consider these reports to be of confidential nature

| **Exact Legal Name of Respondent (Company)** | Year/Period of Report |
| --- | --- |
| Public Service Company of Colorado | End of: 2024/ Q4 |

**INSTRUCTIONS FOR FILING FERC FORM NOS. 1 and 3-Q**

# GENERAL INFORMATION

## Purpose

FERC Form No. 1 (FERC Form 1) is an annual regulatory requirement for Major electric utilities, licensees and others (18 C.F.R. § 141.1). FERC Form No. 3-Q ( FERC Form 3-Q) is a quarterly regulatory requirement which supplements the annual financial reporting requirement (18 C.F.R. § 141.400). These reports are designed to collect financial and operational information from electric utilities, licensees and others subject to the jurisdiction of the Federal Energy Regulatory Commission. These reports are also considered to be non-confidential public use forms.

## Who Must Submit

Each Major electric utility, licensee, or other, as classified in the Commission's Uniform System of Accounts Prescribed for Public Utilities, Licensees, and Others Subject To the Provisions of The Federal Power Act (18 C.F.R. Part 101), must submit FERC Form 1 (18 C.F.R. § 141.1), and FERC Form 3-Q (18 C.F.R. § 141.400).

Note: Major means having, in each of the three previous calendar years, sales or transmission service that exceeds one of the following:

one million megawatt hours of total annual sales,

100 megawatt hours of annual sales for resale,

500 megawatt hours of annual power exchanges delivered, or

500 megawatt hours of annual wheeling for others (deliveries plus losses).

## What and Where to Submit

Submit FERC Form Nos. 1 and 3-Q electronically through the eCollection portal at https://eCollection.ferc.gov, and according to the specifications in the Form 1 and 3-Q taxonomies.

The Corporate Officer Certification must be submitted electronically as part of the FERC Forms 1 and 3-Q filings.

Submit immediately upon publication, by either eFiling or mail, two (2) copies to the Secretary of the Commission, the latest Annual Report to Stockholders. Unless eFiling the Annual Report to Stockholders, mail the stockholders report to the Secretary of the Commission at:
Secretary
Federal Energy Regulatory Commission 888 First Street, NE
Washington, DC 20426

For the CPA Certification Statement, submit within 30 days after filing the FERC Form 1, a letter or report (not applicable to filers classified as Class C or Class D prior to January 1, 1984). The CPA Certification Statement can be either eFiled or mailed to the Secretary of the Commission at the address above.

The CPA Certification Statement should:

Attest to the conformity, in all material aspects, of the below listed (schedules and pages) with the Commission's applicable Uniform System of Accounts (including applicable notes relating thereto and the Chief Accountant's published accounting releases), and

Be signed by independent certified public accountants or an independent licensed public accountant certified or licensed by a regulatory authority of a State or other political subdivision of the U. S. (See 18 C.F.R. §§ 41.10-41.12 for specific qualifications.)

| Schedules | Pages |
|---|---|
| Comparative Balance Sheet | 110-113 |
| Statement of Income | 114-117 |
| Statement of Retained Earnings | 118-119 |
| Statement of Cash Flows | 120-121 |
| Notes to Financial Statements | 122-123 |

The following format must be used for the CPA Certification Statement unless unusual circumstances or conditions, explained in the letter or report, demand that it be varied. Insert parenthetical phrases only when exceptions are reported.

"In connection with our regular examination of the financial statements of [COMPANY NAME] for the year ended on which we have reported separately under date of [DATE], we have also reviewed schedules [NAME OF SCHEDULES] of FERC Form No. 1 for the year filed with the Federal Energy Regulatory Commission, for conformity in all material respects with the requirements of the Federal Energy Regulatory Commission as set forth in its applicable Uniform System of Accounts and published accounting releases. Our review for this purpose included such tests of the accounting records and such other auditing procedures as we considered necessary in the circumstances.

Based on our review, in our opinion the accompanying schedules identified in the preceding paragraph (except as noted below) conform in all material respects with the accounting requirements of the Federal Energy Regulatory Commission as set forth in its applicable Uniform System of Accounts and published accounting releases." The letter or report must state which, if any, of the pages above do not conform to the Commission's requirements. Describe the discrepancies that exist.

Filers are encouraged to file their Annual Report to Stockholders, and the CPA Certification Statement using eFiling. Further instructions are found on the Commission's website at https://www.ferc.gov/ferc-online/ferc-online/frequently-asked-questions-faqs-efilingferc-online.

Federal, State, and Local Governments and other authorized users may obtain additional blank copies of FERC Form 1 and 3-Q free of charge from https://www.ferc.gov/general-information-0/electric-industry-forms.

## When to Submit

FERC Forms 1 and 3-Q must be filed by the following schedule:

FERC Form 1 for each year ending December 31 must be filed by April 18th of the following year (18 CFR § 141.1), and

Complete each question fully and accurately, even if it has been answered in a previous report. Enter the word "None" where it truly and completely states the fact.

For any page(s) that is not applicable to the respondent, omit the page(s) and enter "NA," "NONE," or "Not Applicable" in column (d) on the List of Schedules, pages 2 and 3.

Enter the month, day, and year for all dates. Use customary abbreviations. The "Date of Report" included in the header of each page is to be completed only for resubmissions (see VII. below).

Generally, except for certain schedules, all numbers, whether they are expected to be debits or credits, must be reported as positive. Numbers having a sign that is different from the expected sign must be reported by enclosing the numbers in parentheses.

For any resubmissions, please explain the reason for the resubmission in a footnote to the data field.

Do not make references to reports of previous periods/years or to other reports in lieu of required entries, except as specifically authorized.

Wherever (schedule) pages refer to figures from a previous period/year, the figures reported must be based upon those shown by the report of the previous period/year, or an appropriate explanation given as to why the different figures were used.

Schedule specific instructions are found in the applicable taxonomy and on the applicable blank rendered form.

Definitions for statistical classifications used for completing schedules for transmission system reporting are as follows:

FNS - Firm Network Transmission Service for Self. "Firm" means service that can not be interrupted for economic reasons and is intended to remain reliable even under adverse conditions. "Network Service" is Network Transmission Service as described in Order No. 888 and the Open Access Transmission Tariff. "Self" means the respondent.

FNO - Firm Network Service for Others. "Firm" means that service cannot be interrupted for economic reasons and is intended to remain reliable even under adverse conditions. "Network Service" is Network Transmission Service as described in Order No. 888 and the Open Access Transmission Tariff.

LFP - for Long-Term Firm Point-to-Point Transmission Reservations. "Long-Term" means one year or longer and" firm" means that service cannot be interrupted for economic reasons and is intended to remain reliable even under adverse conditions. "Point-to-Point Transmission Reservations" are described in Order No. 888 and the Open Access Transmission Tariff. For all transactions identified as LFP, provide in a footnote the termination date of the contract defined as the earliest date either buyer or seller can unilaterally cancel the contract.

OLF - Other Long-Term Firm Transmission Service. Report service provided under contracts which do not conform to the terms of the Open Access Transmission Tariff. "Long-Term" means one year or longer and "firm" means that service cannot be interrupted for economic reasons and is intended to remain reliable even under adverse conditions. For all transactions identified as OLF, provide in a footnote the termination date of the contract defined as the earliest date either buyer or seller can unilaterally get out of the contract.

SFP - Short-Term Firm Point-to-Point Transmission Reservations. Use this classification for all firm point-to-point transmission reservations, where the duration of each period of reservation is less than one-year.

NF - Non-Firm Transmission Service, where firm means that service cannot be interrupted for economic reasons and is intended to remain reliable even under adverse conditions.

OS - Other Transmission Service. Use this classification only for those services which can not be placed in the above-mentioned classifications, such as all other service regardless of the length of the contract and service FERC Form. Describe the type of service in a footnote for each entry.

AD - Out-of-Period Adjustments. Use this code for any accounting adjustments or "true-ups" for service provided in prior reporting periods. Provide an explanation in a footnote for each adjustment.

DEFINITIONS

Commission Authorization (Comm. Auth.) -- The authorization of the Federal Energy Regulatory Commission, or any other Commission. Name the commission whose authorization was obtained and give date of the authorization.

Respondent -- The person, corporation, licensee, agency, authority, or other Legal entity or instrumentality in whose behalf the report is made.

# EXCERPTS FROM THE LAW

**Federal Power Act, 16 U.S.C. § 791a-825r**

Sec. 3. The words defined in this section shall have the following meanings for purposes of this Act, to with:

'Corporation' means any corporation, joint-stock company, partnership, association, business trust, organized group of persons, whether incorporated or not, or a receiver or receivers, trustee or trustees of any of the foregoing. It shall not include 'municipalities, as hereinafter defined;

'Person' means an individual or a corporation;

'Licensee, means any person, State, or municipality Licensed under the provisions of section 4 of this Act, and any assignee or successor in interest thereof;

'municipality means a city, county, irrigation district, drainage district, or other political subdivision or agency of a State competent under the Laws thereof to carry and the business of developing, transmitting, unitizing, or distributing power; .....

"project' means. a complete unit of improvement or development, consisting of a power house, all water conduits, all dams and appurtenant works and structures (including navigation structures) which are a part of said unit, and all storage, diverting, or fore bay reservoirs directly connected therewith, the primary line or lines transmitting power there from to the point of junction with the distribution system or with the interconnected primary transmission system, all miscellaneous structures used and useful in connection with said unit or any part thereof, and all water rights, rights-of-way, ditches, dams, reservoirs, Lands, or interest in Lands the use and occupancy of which are necessary or appropriate in the maintenance and operation of such unit;

"Sec. 4. The Commission is hereby authorized and empowered

'To make investigations and to collect and record data concerning the utilization of the water 'resources of any region to be developed, the water-power industry and its relation to other industries and to interstate or foreign commerce, and concerning the location, capacity, development costs, and relation to markets of power sites; ... to the extent the Commission may deem necessary or useful for the purposes of this Act."

FERC Form 3-Q for each calendar quarter must be filed within 60 days after the reporting quarter (18 C.F.R. § 141.400).

### Where to Send Comments on Public Reporting Burden.

The public reporting burden for the FERC Form 1 collection of information is estimated to average 1,168 hours per response, including the time for reviewing instructions, searching existing data sources, gathering and maintaining the data-needed, and completing and reviewing the collection of information. The public reporting burden for the FERC Form 3-Q collection of information is estimated to average 168 hours per response.

Send comments regarding these burden estimates or any aspect of these collections of information, including suggestions for reducing burden, to the Federal Energy Regulatory Commission, 888 First Street NE, Washington, DC 20426 (Attention: Information Clearance Officer); and to the Office of Information and Regulatory Affairs, Office of Management and Budget, Washington, DC 20503 (Attention: Desk Officer for the Federal Energy Regulatory Commission). No person shall be subject to any penalty if any collection of information does not display a valid control number (44 U.S.C. § 3512 (a)).

## GENERAL INSTRUCTIONS

Prepare this report in conformity with the Uniform System of Accounts (18 CFR Part 101) (USofA). Interpret all accounting words and phrases in accordance with the USofA.

Enter in whole numbers (dollars or MWH) only, except where otherwise noted. (Enter cents for averages and figures per unit where cents are important. The truncating of cents is allowed except on the four basic financial statements where rounding is required.) The amounts shown on all supporting pages must agree with the amounts entered on the statements that they support. When applying thresholds to determine significance for reporting purposes, use for balance sheet accounts the balances at the end of the current reporting period, and use for statement of income accounts the current year's year to date amounts.



"Sec. 304.

Every Licensee and every public utility shall file with the Commission such annual and other periodic or special* reports as the Commission may by rules and regulations or other prescribe as necessary or appropriate to assist the Commission in the proper administration of this Act. The Commission may prescribe the manner and FERC Form in which such reports shall be made, and require from such persons specific answers to all questions upon which the Commission may need information. The Commission may require that such reports shall include, among other things, full information as to assets and Liabilities, capitalization, net investment, and reduction thereof, gross receipts, interest due and paid, depreciation, and other reserves, cost of project and other facilities, cost of maintenance and operation of the project and other facilities, cost of renewals and replacement of the project works and other facilities, depreciation, generation, transmission, distribution, delivery, use, and sale of electric energy. The Commission may require any such person to make adequate provision for currently determining such costs and other facts. Such reports shall be made under oath unless the Commission otherwise specifies*.10

"Sec. 309.

The Commission shall have power to perform any and all acts, and to prescribe, issue, make, and rescind such orders, rules and regulations as it may find necessary or appropriate to carry out the provisions of this Act. Among other things, such rules and regulations may define accounting, technical, and trade terms used in this Act; and may prescribe the FERC Form or FERC Forms of all statements, declarations, applications, and reports to be filed with the Commission, the information which they shall contain, and the time within which they shall be field..."

## GENERAL PENALTIES

The Commission may assess up to $1 million per day per violation of its rules and regulations. See FPA § 316(a) (2005), 16 U.S.C. § 825o(a).

**FERC FORM NO. 1**
**REPORT OF MAJOR ELECTRIC UTILITIES, LICENSEES AND OTHER**

**IDENTIFICATION**

| 01 Exact Legal Name of Respondent | 02 Year/ Period of Report |
|---|---|
| Public Service Company of Colorado | End of: 2024/ Q4 |

| 03 Previous Name and Date of Change (If name changed during year) |
|---|
| / |

| 04 Address of Principal Office at End of Period (Street, City, State, Zip Code) |
|---|
| 1800 Larimer Street, Suite 1100, Denver, CO 80202 |

| 05 Name of Contact Person | 06 Title of Contact Person |
|---|---|
| Melissa L. Ostrom | Senior Vice President, Controller |

| 07 Address of Contact Person (Street, City, State, Zip Code) |
|---|
| 414 Nicollet Mall, Minneapolis, MN 55401 |

| 08 Telephone of Contact Person, Including Area Code | 09 This Report is An Original / A Resubmission | 10 Date of Report (Mo, Da, Yr) |
|---|---|---|
| (612) 330-5500 | (1) ☑ An Original<br>(2) ☐ A Resubmission | 04/04/2025 |

**Annual Corporate Officer Certification**

The undersigned officer certifies that:

I have examined this report and to the best of my knowledge, information, and belief all statements of fact contained in this report are correct statements of the business affairs of the respondent and the financial statements, and other financial information contained in this report, conform in all material respects to the Uniform System of Accounts.

| 01 Name | 03 Signature | 04 Date Signed (Mo, Da, Yr) |
|---|---|---|
| Melissa L. Ostrom | Melissa L. Ostrom | 04/04/2025 |
| 02 Title | | |
| Senior Vice President, Controller | | |

Title 18, U.S.C. 1001 makes it a crime for any person to knowingly and willingly to make to any Agency or Department of the United States any false, fictitious or fraudulent statements as to any matter within its jurisdiction.

| Name of Respondent:<br>Public Service Company of Colorado | This report is:<br>(1) ☑ An Original<br>(2) ☐ A Resubmission | Date of Report:<br>04/04/2025 | Year/Period of Report<br>End of: 2024/ Q4 |
|---|---|---|---|

**LIST OF SCHEDULES (Electric Utility)**

Enter in column (c) the terms "none," "not applicable," or "NA," as appropriate, where no information or amounts have been reported for certain pages. Omit pages where the respondents are "none," "not applicable," or "NA".

| Line No. | Title of Schedule<br>(a) | Reference Page No.<br>(b) | Remarks<br>(c) |
|---|---|---|---|
| | **Identification** | 1 | |
| | **List of Schedules** | 2 | |
| 1 | **General Information** | 101 | |
| 2 | **Control Over Respondent** | 102 | |
| 3 | **Corporations Controlled by Respondent** | 103 | |
| 4 | **Officers** | 104 | |
| 5 | **Directors** | 105 | |
| 6 | **Information on Formula Rates** | 106 | |
| 7 | **Important Changes During the Year** | 108 | |
| 8 | **Comparative Balance Sheet** | 110 | |
| 9 | **Statement of Income for the Year** | 114 | |
| 10 | **Statement of Retained Earnings for the Year** | 118 | |
| 12 | **Statement of Cash Flows** | 120 | |
| 12 | **Notes to Financial Statements** | 122 | |
| 13 | **Statement of Accum Other Comp Income, Comp Income, and Hedging Activities** | 122a | |
| 14 | **Summary of Utility Plant & Accumulated Provisions for Dep, Amort & Dep** | 200 | |
| 15 | **Nuclear Fuel Materials** | 202 | N/A |
| 16 | **Electric Plant in Service** | 204 | |
| 17 | **Electric Plant Leased to Others** | 213 | N/A |
| 18 | **Electric Plant Held for Future Use** | 214 | |
| 19 | **Construction Work in Progress-Electric** | 216 | |
| 20 | **Accumulated Provision for Depreciation of Electric Utility Plant** | 219 | |
| 21 | **Investment of Subsidiary Companies** | 224 | |
| 22 | **Materials and Supplies** | 227 | |
| 23 | **Allowances** | 228 | |
| 24 | **Extraordinary Property Losses** | 230a | N/A |
| 25 | **Unrecovered Plant and Regulatory Study Costs** | 230b | |
| 26 | **Transmission Service and Generation Interconnection Study Costs** | 231 | |
| 27 | **Other Regulatory Assets** | 232 | |

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|---|---|---|---|
| 28 | Miscellaneous Deferred Debits | 233 | |
| 29 | Accumulated Deferred Income Taxes | 234 | |
| 30 | Capital Stock | 250 | |
| 31 | Other Paid-in Capital | 253 | |
| 32 | Capital Stock Expense | 254b | N/A |
| 33 | Long-Term Debt | 256 | |
| 34 | Reconciliation of Reported Net Income with Taxable Inc for Fed Inc Tax | 261 | |
| 35 | Taxes Accrued, Prepaid and Charged During the Year | 262 | |
| 36 | Accumulated Deferred Investment Tax Credits | 266 | |
| 37 | Other Deferred Credits | 269 | |
| 38 | Accumulated Deferred Income Taxes-Accelerated Amortization Property | 272 | |
| 39 | Accumulated Deferred Income Taxes-Other Property | 274 | |
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| 41 | Other Regulatory Liabilities | 278 | |
| 42 | Electric Operating Revenues | 300 | |
| 43 | Regional Transmission Service Revenues (Account 457.1) | 302 | N/A |
| 44 | Sales of Electricity by Rate Schedules | 304 | |
| 45 | Sales for Resale | 310 | |
| 46 | Electric Operation and Maintenance Expenses | 320 | |
| 47 | Purchased Power | 326 | |
| 48 | Transmission of Electricity for Others | 328 | |
| 49 | Transmission of Electricity by ISO/RTOs | 331 | N/A |
| 50 | Transmission of Electricity by Others | 332 | |
| 51 | Miscellaneous General Expenses-Electric | 335 | |
| 52 | Depreciation and Amortization of Electric Plant (Account 403, 404, 405) | 336 | |
| 53 | Regulatory Commission Expenses | 350 | |
| 54 | Research, Development and Demonstration Activities | 352 | |
| 55 | Distribution of Salaries and Wages | 354 | |
| 56 | Common Utility Plant and Expenses | 356 | |
| 57 | Amounts included in ISO/RTO Settlement Statements | 397 | |
| 58 | Purchase and Sale of Ancillary Services | 398 | |
| 59 | Monthly Transmission System Peak Load | 400 | |
| 60 | Monthly ISO/RTO Transmission System Peak Load | 400a | N/A |
| 61 | Electric Energy Account | 401a | |
| 62 | Monthly Peaks and Output | 401b | |
| 63 | Steam Electric Generating Plant Statistics | 402 | |

| | | | |
|---|---|---|---|
| 64 | **Hydroelectric Generating Plant Statistics** | 406 | |
| 65 | **Pumped Storage Generating Plant Statistics** | 408 | |
| 66 | **Generating Plant Statistics Pages** | 410 | |
| 66.1 | **Energy Storage Operations (Large Plants)** | 414 | |
| 66.2 | **Energy Storage Operations (Small Plants)** | 419 | |
| 67 | **Transmission Line Statistics Pages** | 422 | |
| 68 | **Transmission Lines Added During Year** | 424 | |
| 69 | **Substations** | 426 | |
| 70 | **Transactions with Associated (Affiliated) Companies** | 429 | |
| 71 | **Footnote Data** | 450 | |
| | **Stockholders' Reports (check appropriate box)** | | |
| | Stockholders' Reports Check appropriate box:<br><br>☑ Two copies will be submitted<br>☐ No annual report to stockholders is prepared | | |

| Name of Respondent:<br>Public Service Company of Colorado | This report is:<br>(1) ☑ An Original<br>(2) ☐ A Resubmission | Date of Report:<br>04/04/2025 | Year/Period of Report<br>End of: 2024/ Q4 |
|---|---|---|---|

## NOTES TO FINANCIAL STATEMENTS

1. Use the space below for important notes regarding the Balance Sheet, Statement of Income for the year, Statement of Retained Earnings for the year, and Statement of Cash Flows, or any account thereof. Classify the notes according to each basic statement, providing a subheading for each statement except where a note is applicable to more than one statement.
2. Furnish particulars (details) as to any significant contingent assets or liabilities existing at end of year, including a brief explanation of any action initiated by the Internal Revenue Service involving possible assessment of additional income taxes of material amount, or of a claim for refund of income taxes of a material amount initiated by the utility. Give also a brief explanation of any dividends in arrears on cumulative preferred stock.
3. For Account 116, Utility Plant Adjustments, explain the origin of such amount, debits and credits during the year, and plan of disposition contemplated, giving references to Commission orders or other authorizations respecting classification of amounts as plant adjustments and requirements as to disposition thereof.
4. Where Accounts 189, Unamortized Loss on Reacquired Debt, and 257, Unamortized Gain on Reacquired Debt, are not used, give an explanation, providing the rate treatment given these items. See General Instruction 17 of the Uniform System of Accounts.
5. Give a concise explanation of any retained earnings restrictions and state the amount of retained earnings affected by such restrictions.
6. If the notes to financial statements relating to the respondent company appearing in the annual report to the stockholders are applicable and furnish the data required by instructions above and on pages 114-121, such notes may be included herein.
7. For the 3Q disclosures, respondent must provide in the notes sufficient disclosures so as to make the interim information not misleading. Disclosures which would substantially duplicate the disclosures contained in the most recent FERC Annual Report may be omitted.
8. For the 3Q disclosures, the disclosures shall be provided where events subsequent to the end of the most recent year have occurred which have a material effect on the respondent. Respondent must include in the notes significant changes since the most recently completed year in such items as: accounting principles and practices; estimates inherent in the preparation of the financial statements; status of long-term contracts; capitalization including significant new borrowings or modifications of existing financing agreements; and changes resulting from business combinations or dispositions. However were material contingencies exist, the disclosure of such matters shall be provided even though a significant change since year end may not have occurred.
9. Finally, if the notes to the financial statements relating to the respondent appearing in the annual report to the stockholders are applicable and furnish the data required by the above instructions, such notes may be included herein.

**1. Summary of Significant Accounting Policies**

**Business and System of Accounts** - PSCo is principally engaged in the regulated generation, purchase, transmission, distribution and sale of electricity and in the regulated purchase, transportation, distribution and sale of natural gas. PSCo is subject to regulation by the FERC and the Colorado Public Utility Commission (CPUC).

**Basis of Accounting** - The accompanying financial statements were prepared in accordance with the accounting requirements of the FERC as set forth in the Uniform System of Accounts and published accounting releases, which is a comprehensive basis of accounting other than Generally Accepted Accounting Principles (GAAP). The following areas represent the significant differences between the Uniform System of Accounts and GAAP:

- Current maturities of long-term debt are included as long-term debt, while GAAP requires such maturities to be classified as current liabilities.
- Accumulated deferred income taxes are shown as long-term assets and liabilities at their gross amounts in the FERC presentation, in contrast to the GAAP presentation as net long-term assets and liabilities.
- Regulatory assets and liabilities are classified as current and noncurrent for GAAP presentation, while the FERC requires all regulatory assets and liabilities to be classified as noncurrent deferred debits and credits, respectively.
- Unrecognized tax benefits are recorded for temporary differences in accounts established for accumulated deferred income taxes in the FERC presentation, in contrast to the GAAP presentation as taxes accrued and noncurrent other liabilities.
- Removal costs for future removal obligations are classified as accumulated depreciation on the utility plant in the FERC presentation and as regulatory liabilities in the GAAP presentation.
- Certain commodity trading purchases and sales transactions are presented gross as expenses and revenues for the FERC presentation; however the net margin is reported as net sales for the GAAP presentation.
- Various expenses such as donations, lobbying, and other non-regulatory expenses are presented as other income deductions for the FERC presentation and reported as operating expenses for the GAAP presentation.
- Income tax expense is shown as a component of operating expense in the FERC presentation, in contrast to the GAAP presentation as a below-the-line deduction from operating income.
- Wholly-owned subsidiaries are reported using the equity method of accounting in the FERC presentation and are required to be consolidated for GAAP.
- Borrowings and repayments with subsidiary companies are investing activities in the FERC statement of cash flows; however, they are operating activities in the GAAP statement of cash flows.
- For certain capital projects where there is recovery of a return on construction work in progress (CWIP), certain amounts of allowance for funds used during construction (AFUDC) are not recognized in CWIP for GAAP, while for the FERC presentation, they are recorded in CWIP but the benefit is deferred as a liability and amortized over the life of the property as a reduction of costs.
- Deferred debt issuance costs are included as a deferred debit, while GAAP presentation includes them with long-term liabilities.
- Regulatory baselines have been specified for qualified and non-qualified pension cost, which are compared to costs recorded for GAAP; amounts above or below these baselines are deferred on a FERC basis.
- A 15-year fixed FERC regulatory amortization is being recorded to reduce the GAAP qualified pension prepaid asset included in rate base, while GAAP remeasures the prepaid amount each period based on actuarial measurement of net periodic pension cost and employer cash contributions to the trust.

If GAAP were followed, these financial statement line items would have values greater/(lesser) than those shown by the FERC presentation of:

| **(Millions of Dollars)** | |
|---|---|
| Balance Sheet: | |
| Net utility plant | $ 385 |
| Current assets | 142 |
| Current liabilities | 426 |
| Other long-term assets | (1,050) |
| Long-term debt and other long-term liabilities | (949) |
| | |
| Statement of Income: | |
| Operating revenue | $ (77) |
| Operating expenses | (69) |
| Other income and deductions | 37 |
| Net interest charges | 4 |

**Subsequent Events -** Management has evaluated the impact of events occurring after Dec. 31, 2024 up to Feb. 27, 2025, the date PSCo's GAAP financial statements were issued and has updated such evaluation for disclosure purposes through the date of the draft. These statements contain all necessary adjustments and disclosures resulting from that evaluation.

**Use of Estimates** — PSCo uses estimates based on the best information available to record transactions and balances resulting from business operations. Estimates are used for items such as plant depreciable lives or potential disallowances, asset retirement obligations (AROs), certain regulatory assets and liabilities, tax provisions, uncollectible amounts, environmental costs, unbilled revenues, jurisdictional fuel and energy cost allocations, actuarially determined benefit costs and wildfire contingencies. Recorded estimates are revised when better information becomes available or actual amounts can be determined. Revisions can affect operating results.

**Regulatory Accounting** — PSCo accounts for income and expense items in accordance with accounting guidance for regulated operations. Under this guidance:

- Certain costs, which would otherwise be charged to expense or other comprehensive income (OCI), are deferred as regulatory assets based on the expected ability to recover the costs in future rates.
- Certain credits, which would otherwise be reflected as income or OCI, are deferred as regulatory liabilities based on the expectation the amounts will be returned to customers in future rates, or because the amounts were collected in rates prior to the costs being incurred.

Estimates and assumptions for recovery of deferred costs and refund of deferred credits are based on specific ratemaking decisions, precedent or other available information. Regulatory assets and liabilities are amortized consistent with the treatment in the rate setting process.

If changes in the regulatory environment occur, PSCo may no longer be eligible to apply this accounting treatment and may be required to eliminate regulatory assets and liabilities. Such changes could have a material effect on PSCo's results of operations, financial condition and cash flows.

See Note 3 for further information.

**Income Taxes** — PSCo accounts for income taxes using the asset and liability method, which requires recognition of deferred tax assets and liabilities for the expected future tax consequences of events that have been included in the financial statements. Income taxes are deferred for all temporary differences between pretax financial and taxable income and between the book and tax bases of assets and liabilities utilizing rates that are scheduled to be in effect when the temporary differences are expected to reverse. The effect of a change in tax rates on deferred tax assets and liabilities is recognized in the period that includes the enactment date.

Utility rate regulation has resulted in the recognition of regulatory assets and liabilities related to income taxes. The effects of PSCo's tax rate changes are generally subject to a normalization method of accounting. Therefore, the revaluation of most of its net deferred taxes upon a tax rate reduction results in the establishment of a net regulatory liability, refundable to utility customers over the remaining life of the related assets. PSCo anticipates that a tax rate increase would predominantly result in the establishment of a regulatory asset, subject to an evaluation of whether future recovery is expected.

Tax credits are recorded when earned unless there is a requirement to defer the benefit and amortize over the book depreciable lives of related property. The requirement to defer and amortize these credits specifically applies to certain federal investment tax credits (ITCs), as determined by tax regulations and PSCo tax elections. For tax credits otherwise eligible to be recognized when earned, PSCo considers the impact of rate regulation to determine if these credits and related adjustments should be deferred as regulatory assets or liabilities.

Deferred tax assets are reduced by a valuation allowance if it is more likely than not that some portion or all of the deferred tax asset will not be realized. This evaluation includes consideration of whether tax credits are expected to be sold at a discount and impact the realization of amounts presented as deferred tax assets. Transferable tax credits are accounted for under ASC 740, *Income Taxes*, and valuation allowances and any adjustments for discounts incurred on sales transactions are recorded to deferred tax expense, typically recovered in regulatory mechanisms.

PSCo measures and discloses uncertain tax positions that it has taken or expects to take in its income tax returns. A tax position is recognized in the financial statements when it is more likely than not that the position will be sustained upon examination based on the technical merits of the position. Recognition of changes in uncertain tax positions are reflected as a component of income tax expense.

Interest and penalties are recorded separately to their respective line items in the income statement.

Xcel Energy Inc. and its subsidiaries, including PSCo file consolidated federal income tax returns as well as consolidated or separate state income tax returns. Federal income taxes paid by Xcel Energy Inc. are allocated to its subsidiaries based on separate company computations. A similar allocation is made for state income taxes paid by Xcel Energy Inc. in connection with consolidated state filings. Xcel Energy Inc. also allocates its own income tax benefits to its direct subsidiaries.

See Note 5 for further information.

**Utility Plant and Depreciation in Regulated Operations —** Utility plant is stated at original cost. The cost of plant includes direct labor and materials, contracted work, overhead costs and AFUDC. The cost of plant retired is charged to accumulated depreciation and amortization. Amounts recovered in rates for future removal costs are recorded as regulatory liabilities. Significant additions or improvements extending asset lives are capitalized, while repairs and maintenance costs and replacement of items determined to be less than a unit of property are charged to expense as incurred.

Utility plant is tested for impairment when it is determined that the carrying value of the assets may not be recoverable. A loss is recognized in the current period if it becomes probable that part of a cost of a plant under construction or recently completed plant will be disallowed for recovery from customers and a reasonable estimate of the disallowance can be made. For investments in utility plant that are abandoned and not expected to go into service, incurred costs and related deferred tax amounts are compared to the discounted estimated future rate recovery, and a loss is recognized, if necessary.

Depreciation expense is recorded using the straight-line method over the plant's commission approved useful life. Actuarial life studies are performed and submitted to the state and federal commissions for review. Upon acceptance by the various commissions, the resulting lives and net salvage rates are used to calculate depreciation. Plant removal costs are typically recognized at the amounts recovered in rates as authorized by the applicable regulator. Depreciation expense, expressed as a percentage of average depreciable property, was approximately 3.8% in 2024 and 3.6% in 2023.

**AROs —** PSCo records AROs as a liability in the period incurred (if fair value can be reasonably estimated), with the offsetting/associated costs capitalized as a long-lived asset. The liability is generally increased over time by applying the effective interest method of accretion and the capitalized costs are typically depreciated over the useful life of the long-lived asset. Changes resulting from revisions to timing or amounts of expected asset retirement cash flows are recognized as an increase or a decrease in the ARO.

See Note 8 for further information.

**Benefit Plans and Other Postretirement Benefits —** PSCo maintains pension and postretirement benefit plans for eligible employees. Recognizing the cost of providing benefits and measuring the projected benefit obligation of these plans requires management to make various assumptions and estimates.

Certain unrecognized actuarial gains and losses and unrecognized prior service costs or credits are deferred as regulatory assets and liabilities, rather than recorded as other comprehensive income, based on regulatory recovery mechanisms.

See Note 7 for further information.

**Environmental Costs —** Environmental costs are recorded when it is probable PSCo is liable for remediation costs and the amount can be reasonably estimated. Costs are deferred as a regulatory asset if it is probable that the costs will be recovered from customers in future rates. Otherwise, the costs are expensed. For certain environmental costs related to facilities currently in use, such as for emission-control equipment, the cost is capitalized and depreciated over the life of the plant.

Estimated remediation costs are regularly adjusted as estimates are revised and remediation is performed. If other participating potentially responsible parties exist and acknowledge their potential involvement with a site, costs are estimated and recorded only for PSCo's expected share of the cost.

Future costs of restoring sites are treated as a capitalized cost of plant retirement.

See Note 8 for further information.

**Revenue from Contracts with Customers —** Performance obligations related to the sale of energy are satisfied as energy is delivered to customers. PSCo recognizes revenue that corresponds to the price of the energy delivered to the customer. The measurement of energy sales to customers is generally based on the reading of their meters, which occurs systematically throughout the month. At the end of each month, amounts of energy delivered to customers since the date of the last meter reading are estimated, and the corresponding unbilled revenue is recognized.

A separate financing component of collections from customers is not recognized as contract terms are short-term in nature. Revenues are net of any excise or sales taxes or fees.

PSCo recognizes physical sales to customers (native load and wholesale) on a gross basis in electric revenues and cost of sales. PSCo participates in SPP WEIS. Revenues for short-term physical wholesale sales of excess energy transacted through the imbalance market are recorded on a gross basis. Other revenues and charges settled/facilitated through SPP WEIS are recorded on a net basis in cost of sales.

**Cash and Cash Equivalents** — PSCo considers investments in instruments with a remaining maturity of three months or less at the time of purchase to be cash equivalents.

**Accounts Receivable and Allowance for Bad Debts —** Accounts receivable are stated at the actual billed amount net of an allowance for bad debts. PSCo establishes an allowance for uncollectible receivables based on a policy that reflects its expected exposure to the credit risk of customers. As of Dec. 31, 2024 and 2023, the allowance for bad debts was $50 million and $56 million, respectively.

**Inventory** — Inventory is recorded at the lower of average cost or net realizable value.

**Fair Value Measurements —** PSCo presents cash equivalents, interest rate derivatives, commodity derivatives and pension and postretirement plan assets at estimated fair values in its financial statements.

For interest rate derivatives, quoted prices based primarily on observable market interest rate curves are used to estimate fair value. For commodity derivatives, the most observable inputs available are generally used to determine the fair value of each contract. In the absence of a quoted price, quoted prices for similar contracts or internally prepared valuation models may be used to determine fair value.

For the pension and postretirement plan assets, published trading data and pricing models, generally using the most observable inputs available, are utilized to determine fair value for each security.

See Notes 6 and 7 for further information.

**Derivative Instruments** — PSCo uses derivative instruments in connection with its commodity trading activities, and to manage risk associated with changes in interest rates and utility commodity prices, including forward contracts, futures, swaps and options. Derivatives not qualifying for the normal purchases and normal sales exception are recorded on the balance sheets at fair value as derivative instruments. Classification of changes in fair value for those derivative instruments is dependent on the designation of a qualifying hedging relationship.

Changes in fair value of derivative instruments not designated in a qualifying hedging relationship are reflected in current earnings or as a regulatory asset or liability. Classification as a regulatory asset or liability is based on commission approved regulatory recovery mechanisms.

Gains or losses on commodity trading transactions are recorded as a component of electric operating revenues.

**Normal Purchases and Normal Sales —** PSCo enters into contracts for purchases and sales of commodities for use and sale in its operations. At inception, contracts are evaluated to determine whether they contain a derivative, and if so, whether they may be exempted from derivative accounting if designated as normal purchases or normal sales.

**Commodity Trading Operations —** Commodity trading activities are not associated with energy produced from PSCo's generation assets or energy and capacity purchased to serve native load. Commodity trading contracts are recorded at fair market value and commodity trading results include the impact of all margin-sharing mechanisms.

See Note 6 for further information.

***AFUDC*** — AFUDC represents the cost of capital used to finance utility construction activity and is computed by applying a composite financing rate to qualified CWIP. The amount of AFUDC capitalized as a utility construction cost is credited to other nonoperating income (for equity capital) and interest charges (for debt capital). AFUDC amounts capitalized are included in PSCo's rate base.

***Alternative Revenue*** — Certain rate rider mechanisms (including decoupling and demand side management (DSM) programs) qualify as alternative revenue programs. These mechanisms arise from instances in which the regulator authorizes a future surcharge in response to past activities or completed events. When certain criteria are met, including expected collection within 24 months, revenue is recognized, which may include incentives and return on rate base items. Billing amounts are revised periodically for differences between total amount collected and revenue earned, which may increase or decrease the level of revenue collected from customers. Alternative revenues arising from these programs are presented on a gross basis and disclosed separately from revenue from contracts with customers.

***Conservation Programs*** — The costs incurred for DSM programs are deferred if it is probable future revenue will be provided to permit recovery of the incurred cost. Revenues recognized for incentive programs designed for recovery of DSM program costs and/or conservation performance incentives are limited to amounts expected to be collected within 24 months from the year in which they are earned.

PSCo's DSM program costs are recovered through rider mechanisms. Regulatory assets are recognized to reflect the amount of costs or earned incentives that have not yet been collected from customers.

***Emission Allowances*** — Emissions allowances are recorded at cost, including broker commission fees. The inventory accounting model is utilized for all emissions allowances and any sales of these allowances are included in electric revenues.

***Renewable Energy Credits (RECs)*** — Cost of RECs that are utilized for compliance is recorded as electric fuel and purchased power expense. An inventory accounting model is used to account for RECs.

Sales of RECs are recorded in electric revenues on a gross basis. Cost of these RECs and amounts credited to customers under margin-sharing mechanisms are recorded in electric fuel and purchased power expense.

## 2. Joint Ownership of Generation, Transmission and Gas Facilities

Jointly owned assets as of Dec. 31, 2024:

| (Millions of Dollars, Except Percent Owned) | Plant in Service | Accumulated Depreciation | Percent Owned |
|---|---|---|---|
| Electric generation: | | | |
| Hayden Unit 1 | $ 158 | $ 117 | 76 % |
| Hayden Unit 2 | 152 | 93 | 37 |
| Hayden common facilities | 45 | 33 | 53 |
| Craig Units 1 and 2 | 82 | 58 | 10 |
| Craig common facilities | 40 | 27 | 7 |
| Comanche Unit 3 | 933 | 212 | 67 |
| Comanche common facilities | 29 | 5 | 77 |
| Electric transmission: | | | |
| Transmission and other facilities | 190 | 75 | Various |
| Gas transmission: | | | |
| Rifle, CO to Avon, CO | 28 | 10 | 60 |
| Gas transmission compressor | 8 | 3 | 50 |
| Total [a] | $ 1,665 | $ 633 | |

[a] Projects additionally include $28 million in CWIP

PSCo's share of operating expenses and construction expenditures is included in the applicable utility accounts. Respective owners are responsible for providing their own financing.

## 3. Regulatory Assets and Liabilities

Regulatory assets and liabilities are created for amounts that regulators may allow to be collected or may require to be paid back to customers in future electric and natural gas rates. PSCo would be required to recognize the write-off of regulatory assets and liabilities in net income or OCI if changes in the utility industry no longer allow for the application of regulatory accounting guidance under GAAP.

Components of regulatory assets:

BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

| | |
|---|---|
| Federal Power Act Section 202(c) | ) |
| Emergency Order: Tri-State | ) |
| Generation and Transmission | ) |
| Association, Platte River Power | ) |
| Authority, Salt River Project, | ) |
| PacifiCorp, and Xcel Energy | ) |

Exhibit to
Motion to Intervene and Request for Rehearing and Stay of
Public Interest Organizations

Exhibit 2-57:
2018 SIP Element Adopted

# Chapter 6 Best Available Retrofit Technology

**Table 6 - 2 BART Determinations for Colorado Sources**

| Emission Unit | Assumed ** NOx Control Type | NOx Emission Limit | Assumed ** $SO_2$ Control Type | $SO_2$ Emission Limit | Assumed ** Particulate Control and Emission Limit |
|---|---|---|---|---|---|
| **Cemex - Lyons** Kiln | Selective Non-Catalytic Reduction System | 255.3 lbs/hr (30-day rolling average)<br><br>901.0 tons/yr (12-month rolling average) | None | 25.3 lbs/hr (12-month rolling average)<br><br>95.0 tons/yr (12-month rolling average) | Fabric Filter Baghouse *<br><br>0.275 lb/ton of dry feed<br><br>20% opacity |
| **Cemex - Lyons** Dryer | None | 13.9 tons/yr | None | 36.7 tons/yr | Fabric Filter Baghouse*<br><br>22.8 tons/yr<br><br>10% opacity |
| **CENC** Unit 4 | Low NOx Burners with Separated Over-Fire Air | 0.37 lb/MMBtu (30-day rolling average)<br><br>Or<br><br>0.26 lb/MMBtu Combined Average for Units 4 & 5 (30-day rolling average) | None | 1.0 lb/MMBtu (30-day rolling average) | Fabric Filter Baghouse*<br><br>0.07 lb/MMBtu |
| **CENC** Unit 5 | Low NOx Burners with Separated Over-Fire Air, and Selective Non-Catalytic Reduction System | 0.19 lb/MMBtu (30-day rolling average)<br><br>Or<br><br>0.26 lb/MMBtu Combined Average for Units 4 & 5 (30-day rolling average) | None | 1.0 lb/MMBtu (30-day rolling average) | Fabric Filter Baghouse*<br><br>0.07 lb/MMBtu |
| **Comanche** Unit 1 | Low NOx Burners* | 0.20 lb/MMBtu (30-day rolling average)<br><br>0.15 lb/MMBtu (combined annual average for units 1 & 2) | Lime Spray Dryer* | 0.12 lb/MMBtu (30-day rolling average)<br><br>0.10 lb/MMBtu (combined annual average for units 1 & 2) | Fabric Filter Baghouse*<br><br>0.03 lb/MMBtu |

| | | | | | |
|---|---|---|---|---|---|
| **Comanche** Unit 2 | Low NOx Burners* | 0.20 lb/MMBtu (30-day rolling average)<br><br>0.15 lb/MMBtu (combined annual average for units 1 & 2) | Lime Spray Dryer* | 0.12 lb/MMBtu (30-day rolling average)<br><br>0.10 lb/MMBtu (combined annual average for units 1 & 2) | Fabric Filter Baghouse*<br><br>0.03 lb/MMBtu |
| **Craig** Unit 1 | Selective Catalytic Reduction System | *** | Wet Limestone scrubber* | 0.11 lb/MMBtu (30-day rolling average) | Fabric Filter Baghouse*<br><br>0.03 lb/MMBtu |
| **Craig** Unit 2 | Selective Catalytic Reduction System | 0.08 lb/MMBtu (30-day rolling average) | Wet Limestone scrubber* | 0.11 lb/MMBtu (30-day rolling average) | Fabric Filter Baghouse*<br><br>0.03 lb/MMBtu |
| **Hayden** Unit 1 | Selective Catalytic Reduction System | 0.08 lb/MMBtu (30-day rolling average) | Lime Spray Dryer* | 0.13 lb/MMBtu (30-day rolling average) | Fabric Filter Baghouse*<br><br>0.03 lb/MMBtu |
| **Hayden** Unit 2 | Selective Catalytic Reduction System | 0.07 lb/MMBtu (30-day rolling average) | Lime Spray Dryer* | 0.13 lb/MMBtu (30-day rolling average) | Fabric Filter Baghouse*<br><br>0.03 lb/MMBtu |
| **Martin Drake** Unit 5 | Ultra Low-NOx Burners (including Over-Fire Air) | 0.31 lb/MMBtu (30-day rolling average) | Dry Sorbent Injection | 0.26 lb/MMBtu (30-day rolling average) | Fabric Filter Baghouse*<br><br>0.03 lb/MMBtu |
| **Martin Drake** Unit 6 | Ultra Low-NOx Burners (including Over-Fire Air) | 0.31 lb/MMBtu (30-day rolling average) | Lime Spray Dryer or Equivalent Control Technology | 0.13 lb/MMBtu (30-day rolling average) | Fabric Filter Baghouse*<br><br>0.03 lb/MMBtu |
| **Martin Drake** Unit 7 | Ultra Low-NOx Burners (including Over-Fire Air) | 0.29 lb/MMBtu (30-day rolling average) | Lime Spray Dryer or Equivalent Control Technology | 0.13 lb/MMBtu (30-day rolling average) | Fabric Filter Baghouse*<br><br>0.03 lb/MMBtu |

* Controls are already operating

** Based on the state's BART analysis, the "assumed" technology reflects the control option found to render the BART emission limit achievable. The "assumed" technology listed in the above table is not a requirement.

*** Craig Unit 1 will either close on or before December 31, 2025 ***or*** cease burning coal no later than August 31, 2021 with the option to convert the unit to natural-gas firing by August 31, 2023. In the case of a conversion to natural-gas firing, a 30-day rolling average NOx emission limit of no more than 0.07 lb/MMBtu will be effective after August 31, 2021. Effective January 1, 2017 (first compliance date January 31, 2017), Craig Unit 1 will be subject to a NOx emission limit of 0.28 lb/MMBtu 30-day rolling average until closing or converting to natural gas. Additionally, an annual NOx limit of 4,065 tons per year will be effective December 31, 2019 on a calendar year basis beginning in 2020 for Craig Unit 1. The Division shall be notified in writing by the owner-operator no later than February 28, 2021 whether Craig Unit 1 will close or convert to gas.

### *6.4.3.4 BART Determination for Tri-State Generation and Transmission Association's Craig Facility*

Craig Units 1 and 2 are BART-eligible, being fossil-fuel steam electric plants of more than 250 MMBtu/hr heat input with the potential to emit 250 tons or more of haze forming pollution ($NO_x$, $SO_2$, $PM_{10}$), and having commenced operation in the 15-year period prior to August 7, 1977. These boilers also cause or contribute to visibility impairment at a federal Class I area at or above a 0.5 deciview change. Tri-State submitted a BART Analysis to the Division on July 31, 2006 with revisions, updates, and/or comments submitted on October 25, 2007, December 31, 2009, May 14, 2010, June 4, 2010 and July 30, 2010.

**SO2 BART Determination for Craig - Units 1 and 2**

*Wet FGD Upgrades* – As discussed in EPA's BART Guidelines, electric generating units (EGUs) with existing controls achieving removal efficiencies of greater than 50 percent do not need to be evaluated for potential removal of controls and replacement with new controls. Therefore, the following wet scrubber upgrades were considered for Craig Units 1 and 2, if technically feasible.

- *Elimination of bypass reheat*: The FGD system bypass was redesigned to eliminate bypass of the FGD system except for boiler safety situations in 2003-2004.
- *Installation of liquid distribution rings:* Tri-State determined that installation of perforated trays, described below, accomplished the same objective.
- *Installation of perforated trays:* Upgrades during 2003-2004 included installation of a perforated plate tray in each scrubber module.
- *Use of organic acid additives:* Organic acid additives were considered but not selected for the following reasons:
  1. Dibasic Acid (DBA) has not been tested at the very low inlet $SO_2$ concentrations seen at Craig Units 1 and 2.
  2. DBA could cause changes in sulfite oxidation with impacts on $SO_2$ removal and solids settling and dewatering characteristics.
  3. Installation of the perforated plate tray accomplished the same objective of increased $SO_2$ removal.
- *Improve or upgrade scrubber auxiliary equipment:* 2003-2004 upgrades included installation of the following upgrades on limestone processing and scrubber modules on Craig 1 and 2:
  1. Two vertical ball mills were installed for additional limestone processing capability for increased $SO_2$ removal. The two grinding circuit trains were redesigned to position the existing horizontal ball mills and the vertical ball mills in series to accommodate the increased quantity of limestone required for increased removal rates. The two mills in series also were designed to maintain the fine particle size (95% <325 mesh or 44 microns) required for high $SO_2$ removal rates.

2. Forced oxidation within the $SO_2$ removal system was thought necessary to accommodate increased removal rates and maintain the dewatering characteristics of the limestone slurry. Operation, performance, and maintenance of the gypsum dewatering equipment are more reliable with consistent slurry oxidation.
3. A ventilation system was installed for each reaction tank.
4. A new mist eliminator wash system was installed due to the increased gas flow through the absorbers since flue gas bypass was eliminated, which increased demand on the mist eliminator system. A complete redesign and replacement of the mist eliminator system including new pads and wash system improved the reliability of the individual modules by minimizing down time for washing deposits out of the pads.
5. Tri-State installed new module outlet isolation damper blades. The new blades, made of a corrosion-resistant nickel alloy, allow for safer entry into the non-operating module for maintenance activities.
6. Various dewatering upgrades were completed. Dewatering the gypsum slurry waste is done to minimize the water content in waste solids prior to placements of the solids in reclamation areas at the Trapper Mine. The gypsum solids are mixed or layered with ash and used for fill during mine reclamation at Trapper Mine. The installed system was designed for the increased capacity required for increased $SO_2$ removal. New hydrocyclones and vacuum drums were installed as well as a new conveyor and stack out system for solid waste disposal.
7. Instrumentation and controls were modified to support all of the new equipment.

- *Redesign spray header or nozzle configuration:* The slurry spray distribution was modified during 2003-2004. The modified slurry spray distribution system improved slurry spray characteristics and was designed to minimize pluggage in the piping.

Therefore, there are no technically feasible upgrade options for Craig Station Units 1 and 2. However, the state evaluated the option of tightening the emission limit for Craig Units 1 and 2 through the five-factor analysis and determined that a more stringent 30-day rolling $SO_2$ limit of 0.11 lbs/MMBtu represents an appropriate level of emissions control for this wet FGD control technology based on current emissions and operations. The tighter emission limits are achievable without additional capital investment. An SO2 limit lower than 0.11 lbs/MMBtu would likely require additional capital expenditure and is not reasonable for the small incremental visibility improvement of 0.02 deciview.

The projected visibility improvements attributed to the alternatives are as follows:

| SO2 Control Method | Craig – Unit 1 | | Craig – Unit 2 | |
|---|---|---|---|---|
| | SO2 Annual Emission Rate (lb/MMBtu) | 98th Percentile Impact (Δdv) | SO2 Annual Emission Rate (lb/MMBtu) | 98th Percentile Impact (Δdv) |
| Daily Maximum (3-yr) | 0.17 | | 0.16 | |
| Wet FGD | 0.11 | 0.03 | 0.11 | 0.03 |
| Wet FGD | 0.07 | 0.05 | 0.07 | 0.05 |

Based upon its consideration of the five factors summarized herein and detailed in Appendix C, the state has determined that SO2 BART is the following SO2 emission rates:

Craig Unit 1: 0.11 lb/MMBtu (30-day rolling average)
Craig Unit 2: 0.11 lb/MMBtu (30-day rolling average)

The state assumes that the BART emission limits can be achieved through the operation of existing lime spray dryers (LSD). The 30-day rolling SO2 limit of 0.11 lbs/MMBtu represents an appropriate level of emissions control associated with semi-dry FGD control technology.

**Particulate Matter BART Determination for Craig - Units 1 and 2**

The Division has determined that the existing Unit 1 and 2 emission limit of 0.03 lb/MMBtu ($PM/PM_{10}$) represents the most stringent control option. The units are exceeding a PM control efficiency of 95%, and the control technology and emission limits are BART for $PM/PM_{10}$. The state assumes that the BART emission limit can be achieved through the operation of the existing pulse jet fabric filter baghouses.

**NOx BART Determination for Craig - Units 1 and 2**

Potential modifications to the ULNBs, neural network systems, selective non-catalytic reduction (SNCR), and selective catalytic reduction (SCR) were determined to be technically feasible for reducing NOx emissions at Craig Units 1 and 2.

The following tables list the emission reductions, annualized costs and cost effectiveness of the control alternatives:

| Craig Unit 1 - $NO_x$ Cost Comparisons | | | |
|---|---|---|---|
| Alternative | Emissions Reduction (tpy) | Annualized Cost ($) | Cost Effectiveness ($/ton) |
| Baseline | 0 | $0 | $0 |
| SNCR | 779 | $3,797,000 | $4,877 |
| SCR | 4,048 | $25,036,709 | $6,184 |

| Craig Unit 2 - NOx Cost Comparisons | | | |
|---|---|---|---|
| Alternative | Emissions Reduction (tpy) | Annualized Cost ($) | Cost Effectiveness ($/ton) |
| Baseline | 0 | $0 | $0 |
| SNCR | 806 | $3,797,000 | $4,712 |
| SCR | 3,975 | $25,036,709 | $6,298 |

The energy and non-air quality impacts of SNCR are increased power needs, potential for ammonia slip, potential for visible emissions, and hazardous materials storage and handling.

There are no remaining useful life issues for the alternatives as the sources will remain in service for the 20-year amortization period.

The projected visibility improvements attributed to the alternatives are as follows:

| NOx Control Method | Craig – Unit 1 | | Craig – Unit 2 | |
|---|---|---|---|---|
| | NOx Annual Emission Rate (lb/MMBtu) | 98th Percentile Impact (Δdv) | NOx Annual Emission Rate (lb/MMBtu) | 98th Percentile Impact (Δdv) |
| Daily Maximum (3-yr) | 0.35 | | 0.35 | |
| SNCR | 0.24 | 0.31 | 0.23 | 0.31 |
| SCR | 0.07 | 1.01 | 0.08 | 0.94 |

While potential modifications to the ULNB burners and a neural network system were also found to be technically feasible, these options did not provide the same level of reductions as SNCR or SCR, which are included within the ultimate BART determination for Units 1 and 2. Therefore, these options were not further considered in the technical analysis.

Based upon its consideration of the five factors summarized herein and detailed in Appendix C, the state has determined that NOx BART is the following NOx emission rates:

Craig Unit 1: 0.070 lb/MMBtu (30-day rolling average)

Craig Unit 2: 0.080 lb/MMBtu (30-day rolling average)

The 0.08 lb/MMbtu limit for Unit 2 was based upon evidence before the AQCC in 2010, and took into consideration both cost and feasibility. Significant progress towards installation of SCR at Unit 2 has been made, and the vendor has guaranteed performance at the 0.08 lb/MMBtu 30-day rolling average NOx limit. Both vendor performance and equipment performance can improve over time, and the Division has determined, and Tri-State has agreed, that Tri-State can achieve a 0.07 lb/MMBtu NOx limit at Unit 1. The state assumes that the BART emission limits can be achieved through the operation of SCR. For SCR at Units 1 and 2, the cost per ton of emissions removed, coupled with the estimated visibility improvements gained, falls above the guidance criteria presented earlier in Chapter 6. The criteria guide the state's general approach to these policy considerations, but are not binding. Therefore, the state deviates from the guidance criteria in this case due to the fact that Tri-State has agreed to achieve the proposed emission rates at Craig Units 1 and 2 and the notable visibility improvements..

- Unit 1: $6,184 per ton NOx removed; 1.01 deciview of improvement
- Unit 2: $6,298 per ton NOx removed; 0.94 deciview of improvement

To the extent practicable, any technological application Tri-State utilizes to achieve these BART emission limits shall be installed, maintained, and operated in a manner consistent with good air pollution control practices for minimizing emissions. Once EPA approves this revision to the Regional Haze SIP, Tri-State will be required to meet the 0.07 lb/MMBtu NOx emission limit by August 31, 2021. Once the revised emission limit is approved, Tri-State will begin the design and development of bid documents, engage in a process to review bids and select a contractor for the multi-year construction project. Based on Tri-State's experience at Unit 2 (where construction and installation of SCR is already underway), and taking into consideration such factors as the weather in Craig, Colorado, the coordination necessary between the various owners of Unit 1, electric utilities and regional entities responsible for the bulk electric system, and compliance deadlines for other similar types of facilities in Colorado, Arizona and Wyoming, the Division has determined that the compliance deadline of August 31, 2021 is as expeditiously as practicable as SCR can be installed at Unit 1. This BART determination is the result of an agreement between Tri-State, WildEarth Guardians, the National Parks Conservation Association, EPA, and the state to resolve an appeal of EPA's approval of Craig Station –related elements of Colorado's Regional Haze Plan. This BART determination is consistent with the information provided by the FLMs and is supported by the associated visibility improvement information as well as the SCR cost information provided in the SIP materials and otherwise reflected in the 2014 hearing record.

In 2016, based on new information provided from an agreement amongst Tri-State, WildEarth Guardians, the National Parks Conservation Association, EPA, and the state, the state conducted a BART reassessment for Craig Unit 1. This reassessment evaluates the additional scenarios:

Scenario 1 (Close by December 31, 2025): The first table below assumes an amortization period of four years and four months of operation from the projected compliance date to the date of retirement (December 31, 2025) and that control technology could be installed by August 31, 2021, consistent with the 2014 BART determination. In the second table below, an assumed amortization period of eight years of operation[1] is used since a projected compliance date could occur earlier depending on the alternative selected. Both of these assumed amortization periods change the remaining useful life for the alternatives as Craig Unit 1 will no longer remain in service for the 20-year amortization period used in the 2014 BART determination, depending on the alternative selected[2]. Both of these reduced timeframes change the cost effectiveness for the alternatives as follows:

[1] Operation period begins calendar year 2018 (December 31, 2017).
[2] EPA finalized revisions of the Air Pollution Cost Control Manual (Chapters 1 and 2) in May 2016; these revisions change the amortization period for SCR from 20 years to 30 years. The amortization period for SNCR remains 20 years.

| Craig Unit 1 - $NO_x$ Cost Comparisons (assuming four years, four months of operation) | | | |
|---|---|---|---|
| Alternative | Emissions Reduction (tpy) | Annualized Cost ($) | Cost Effectiveness ($/ton) |
| Baseline | 0 | $0 | $0 |
| SNCR | 779 | $6,172,522 | $7,928 |
| SCR | 4,048 | $64,106,699 | $15,835 |

| Craig Unit 1 - $NO_x$ Cost Comparisons (assuming eight years of operation) | | | |
|---|---|---|---|
| Alternative | Emissions Reduction (tpy) | Annualized Cost ($) | Cost Effectiveness ($/ton) |
| Baseline | 0 | $0 | $0 |
| SNCR | 779 | $4,755,842 | $6,109 |
| SCR | 4,048 | $41,476,535 | $10,245 |

Based on this assessment, regardless of the amortization period used, both SNCR and SCR are not cost effective when the remaining useful life is shortened, and when considering the remaining BART factors as discussed in Appendix C. For Craig Unit 1, a NOx emission limit of 0.07 lb/MMBtu (2014 BART determination) is BART under a 20 or 30 year remaining useful life.

or;

Scenario 2: A cease coal burning date of August 31, 2021 with the option to convert the unit to natural-gas firing by August 31, 2023. In the case of a conversion to natural-gas firing, a 30-day rolling average NOx emission limit of no more than 0.07 lb/MMBtu applies after August 31, 2021. This scenario (without the inclusions below) is equivalent to the 2014 BART determination.

Both of these scenarios include a 30-day rolling average NOx emission limit of 0.28 lb/MMBtu that will commence on January 1, 2017 (first compliance date January 31, 2017) and be effective until either closure or conversion to natural gas. Additionally, an annual NOx limit of 4,065 tons per year will be effective December 31, 2019 on a calendar year basis beginning in 2020 for Craig Unit 1.

The scenario options under this BART reassessment are the result of an agreement. This reassessment relies on the 2014 BART determination for Craig Unit 1 and supplements that determination to reflect the terms of the agreement. This agreement achieves greater air quality benefits than the 2011 Regional Haze SIP. Both of these scenarios achieve greater NOx reductions and other environmental co-benefits compared to the 2014 BART determination. Consistent with the agreement, Craig Unit 1 will either close on or before December 31, 2025 ***or*** cease burning coal by August 31, 2021 with the option to convert the unit to natural-gas firing by August 31, 2023. In the case of a conversion to natural-gas firing, a 30-day rolling average NOx emission limit of no more than 0.07 lb/MMBtu will apply after August 31, 2021. Effective January 1, 2017 (first compliance date January 31, 2017), Craig Unit 1 will be subject to a NOx emission

limit of 0.28 lb/MMBtu 30-day rolling average until closure or conversion to natural gas. Additionally, an annual NOx limit of 4,065 tons per year will be effective on December 31, 2019 on a calendar year basis beginning in 2020 for Craig Unit 1.

A complete analysis that supports the BART determination for Craig Station Units 1 and 2 and the BART reassessment for Unit 1, including substantial cost information for NOx controls, can be found in Appendix C.

### *8.5.2 Point Source RP Determinations*

The following summarizes the RP control determinations that will apply to each source.

**Table 8-2 RP Control Determinations for Colorado Sources**

| Emission Unit | Assumed** NOx Control Type | NOx Emission Limit | Assumed** $SO_2$ Control Type | $SO_2$ Emission Limit | Assumed** Particulate Control and Emission Limit |
|---|---|---|---|---|---|
| **Rawhide** Unit 101 | Enhanced Combustion Control* | 0.145 lb/MMBtu (30-day rolling average) | Lime Spray Dryer* | 0.11 lb/MMBtu (30-day rolling average) | Fabric Filter Baghouse*<br><br>0.03 lb/MMBtu |
| **CENC** Unit 3 | No Control | 246 tons per year (12-month rolling total) | No Control | 1.2 lbs/MMBtu | Fabric Filter Baghouse*<br><br>0.07 lb/MMBtu |
| **Nixon** Unit 1 | Ultra-low NOx burners with Over-Fire Air | 0.21 lb/MMBtu (30-day rolling average) | Lime Spray Dryer | 0.11 lb/MMBtu (30-day rolling average) | Fabric Filter Baghouse*<br><br>0.03 lb/MMBtu |
| **Clark** Units 1 &2 | Shutdown 12/31/2013 | 0 | Shutdown 12/31/2013 | 0 | Shutdown 12/31/2013 |
| **Holcim - Florence** Kiln | SNCR | 2.73 lbs/ton clinker (30-day rolling average)<br><br>2,086.8 tons/year | Wet Lime Scrubber* | 1.30 lbs/ton clinker (30-day rolling average)<br><br>721.4 tons/year | Fabric Filter Baghouse*<br>246.3 tons/year |
| **Nucla** | No Control | 0.5 lb/MMBtu (30-day rolling average)*** | Limestone Injection* | 0.4 lb/MMBtu (30-day rolling average) | Fabric Filter Baghouse*<br><br>0.03 lb/MMBtu |
| **Craig** Unit 3 | SNCR | 0.28 lb/MMBtu (30-day rolling average) | Lime Spray Dryer* | 0.15 lb/MMBtu (30-day rolling average) | Fabric Filter Baghouse*<br><br>0.013 lb/MMBtu filterable PM<br><br>0.012 lb/MMBtu PM10 |
| **Cameo** | Shutdown 12/31/2011 | 0 | Shutdown 12/31/2011 | 0 | Shutdown 12/31/2011 |

* Controls are already operating

** Based on the state's RP analysis, the "assumed" technology reflects the control option found to render the RP emission limit achievable. The "assumed" technology listed in the above table is not a requirement.

*** Nucla Station will close on or before December 31, 2022. Additionally, an annual NOx limit of 952 tons per year will be effective on January 1, 2020 beginning in 2020 on a calendar year basis for Nucla Station.

### *8.5.2.6 RP Determination for Tri-State Generation and Transmission Association's Nucla Facility*

The Tri-State Nucla Station is located in Montrose County about 3 miles southeast of the town of Nucla, Colorado. The Nucla Station consists of one coal fired steam driven electric generating unit (Unit 4), with a rated electric generating capacity of 110 MW (gross), which was placed into service in 1987. Nucla Unit 4 is considered by the Division to be eligible for the purposes of Reasonable Progress, being an industrial boiler with the potential to emit 40 tons or more of haze forming pollution ($NO_x$, $SO_2$, $PM_{10}$) at a facility with a Q/d impact greater than 20. Tri-State Generation and Transmission Association (Tri-State) provided information relevant to RP to the Division on December 31, 2009, May 14, 2010, June 4, 2010 and July 30, 2010.

**SO2 RP Determination for Nucla – Unit 4**

Limestone injection improvements, a spray dry absorber (SDA) system (or dry FGD), limestone injection improvements with a SDA, hydrated ash reinjection (HAR), and HAR with limestone injection improvements were determined to be technically feasible for reducing SO2 emissions from Nucla Unit 4. Study-level information for HAR systems at Nucla or any other EGU in the western United States were not available for use in evaluating costs. Since the option to install a dry FGD alone (even without improving limestone injection) provides a better estimated control efficiency than a HAR system plus limestone injection improvements, the HAR system was not considered further in this analysis.

The following tables list the emission reductions, annualized costs and cost effectiveness of the control alternatives:

| Nucla Unit 4 - SO2 Cost Comparison | | | |
|---|---|---|---|
| Alternative | Emissions Reduction (tpy) | Annualized Cost ($) | Cost Effectiveness ($/ton) |
| Baseline | 0 | $0 | $0 |
| Limestone Injection Improvements | 526 | $914,290 | $4,161 |
| Spray Dry Absorber (dry FGD) | 1,162 | $7,604,627 | $6,547 |
| Limestone Injection Improvements + dry FGD | 1,254 | $9,793,222 | $7,808 |

A dry FGD system, or limestone injection improvements plus dry FGD system, were eliminated from consideration by the state as unreasonable during this planning period due to: 1) the excessive costs, 2) that they would require replacement of an existing system and installation of a completely new system (with attendant new capital costs and facility space considerations), and 3) the lack of modeled visibility affects associated with these particular SO2 reductions.

There is no energy and non-air quality impacts associated with limestone injection improvements. For dry FGD, the energy and non-air quality impacts include less mercury removal compared to unscrubbed units and significant water usage.

There are no remaining useful life issues for alternatives as the source will remain in service for the 20-year amortization period.

Due to time and domain constraints, projected visibility improvements were not modeled by the state for this analysis.

Nucla already has a system in place to inject limestone into the boiler as required by current state and federal air permits. This system achieves an approximate 70% SO2 emissions reduction capture efficiency at a permitted emission rate of 0.4 lbs/MMBtu limit. Increased SO2 capture efficiency (85%) with the existing limestone injection as an effective system upgrade, by use of more limestone (termed "limestone injection improvements") was evaluated and determined to not be feasible under certain operating conditions. The system cannot be 'run harder' with more limestone to achieve a more stringent SO2 emission limit; the system would have to be reconstructed or redesigned with attendant issues, or possibly require a new or different SO2 system, to meet an 85% capture efficiency.

Based upon its consideration of the five factors summarized herein and detailed in Appendix D, the state has determined that the existing permitted SO2 emission rate for Unit 4 satisfies RP:

Nucla Unit 4: 0.4 lb/MMBtu (30-day rolling average)

The state assumes that the emission limit can be achieved through the operation of the existing limestone injection system.

**PM10 RP Determination for Nucla – Unit 4**

The state has determined that the existing regulatory emissions limit of 0.03 lb/MMBtu represents the most stringent control option. The unit is exceeding a PM control efficiency of 95%, and the emission limit is RP for PM/$PM_{10}$. The state assumes that the emission limit can be achieved through the operation of the existing fabric filter baghouse.

**NOx RP Determination for Nucla – Unit 4**

Selective non-catalytic reduction (SNCR) was determined to be technically feasible for reducing NOx emissions at Nucla Unit 4. SCR is not technically feasible on a circulating fluidized bed coal-fired boiler, and is otherwise not cost-effective, as discussed in Appendix D. With respect to SNCR, however, there is substantial uncertainty surrounding the potential control efficiency achievable by a full-scale SNCR system at a CFB boiler burning western United States coal. The state and Tri-State's estimates vary between 10 – 40% NOx reduction potential, which correlates to between $3,000 - $17,000 per ton NOx reduced and may result in between 100 to 400 tons NOx reduced per year.

The energy and non-air quality impacts of SNCR are increased power needs, potential for ammonia slip, potential for visible emissions, hazardous materials storage and handling.

There are no remaining useful life issues for the alternatives as the sources will remain in service for the 20-year amortization period.

Due to time and domain constraints, projected visibility improvements were not modeled by the state for this analysis. There are several qualitative reasons that NOx controls may be warranted at Nucla. First, NOx control alternatives may result in between 100 – 400 tons of NOx reduced annually. Second, Nucla is within 100 kilometers in proximity to three Class I areas, depicted in the figure above, and within approximately 115 kilometers to five Class I areas, including Utah's Canyonlands and Arches National Parks. Third, Nucla has a limited, small-scale SNCR system for emissions trimming purposes installed.

Based upon its consideration of the five factors summarized herein and detailed in Appendix D, the State has determined that NOx RP for Nucla Unit 4 is no control at the following NOx emission rate:

Nucla Unit 4: 0.5 lb/MMBtu (30-day rolling average)

**Additional Analyses of SO2 and NOx Controls for Nucla**

As state-only requirements of this Reasonable Progress determination, the Commission requires, and Tri-State agrees, that Tri-State conduct a comprehensive four factor analysis of all SO2 and NOx control options for Nucla using site-specific studies and cost information and provide to the state a draft analysis by July 1, 2012. A protocol for the four-factor analysis and studies will be approved by the Division in advance. The analysis will include enhancements or upgrades to the existing limestone injection system for increased SO2 reduction performance, other relevant SO2 control technologies such as lime spray dryers and flue gas desulfurization, and all NOx control options. A final analysis that addresses the state's comments shall be submitted to the state by January 1, 2013. By January 1, 2013, Tri-State shall also conduct appropriate cost analyses, study and, if deemed necessary by the state and the source, testing, as approved by the Division, to inform what performance would be achieved by a full-scale SNCR system at Nucla to determine potential circulating fluidized bed (CFB) boiler-specific NOx control efficiencies. By January 1, 2013, Tri-State shall conduct CALPUFF modeling in compliance with the Division's approved BART-modeling protocol to determine potential visibility impacts the different SO2 and NOx control scenarios for Nucla. Finally, Tri-State shall propose to the state any preferred SO2 and NOx emission control strategies for Nucla by January 1, 2013. On December 26, 2012, Tri-State submitted an updated four-factor analysis and visibility modeling to the Division, with the conclusion that limestone for SO2 control and existing SNCR for NOx reduction remained the preferred strategy.

**Requirements for Nucla Station**

On December 31, 2012, EPA approved Colorado's Regional Haze SIP, including Colorado's Reasonable Progress determination for Nucla Unit 4 (0.5 lb/MMBtu (30-day rolling average)). In 2016, based on new information provided from an agreement amongst Tri-State, WildEarth Guardians, the National Parks Conservation Association, EPA, and the state, the state conducted a Reasonable Progress review of Nucla. This review adds a requirement of a closure date on or before December 31, 2022 for Nucla Station. Additionally, an annual $NO_x$ limit of 952 tons per year will be effective January 1, 2020 on a calendar year basis beginning in 2020.

These requirements are the result of an agreement. The 2022 closure achieves further NOx reductions and other environmental co-benefits than the 2011 RP determination. Consistent with the agreement and in lieu of being subject to stringent requirements as part of the long term strategy for the second implementation period of Regional Haze, Nucla Station will close by December 31, 2022.

Additionally, an annual NOx limit of 952 tons per year will be effective on January 1, 2020 on a calendar year basis beginning in 2020. Nucla Unit 4 will still comply with the 2011 RP determination of 0.5 lb/MMBtu (30-day rolling average) until closure. A complete analysis that supports the RP determination and review for the Nucla facility can be found in Appendix D.

BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

| | |
|---|---|
| Federal Power Act Section 202(c) | ) |
| Emergency Order: Tri-State | ) |
| Generation and Transmission | ) |
| Association, Platte River Power | ) |
| Authority, Salt River Project, | ) |
| PacifiCorp, and Xcel Energy | ) |

Exhibit to
Motion to Intervene and Request for Rehearing and Stay of
Public Interest Organizations

Exhibit 2-58:
Lisa Tiffin 2020 ERP Direct Testimony

**BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF COLORADO**

**PROCEEDING NO. 20A-0528E**

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**APPLICATION OF TRI-STATE GENERATION AND TRANSMISSION ASSOCIATION, INC. FOR APPROVAL OF ITS 2020 ELECTRIC RESOURCE PLAN**

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# DIRECT TESTIMONY AND ATTACHMENTS OF LISA K. TIFFIN ON BEHALF OF TRI-STATE GENERATION AND TRANSMISSION ASSOCIATION, INC.

**December 1, 2020**

Colorado PUC E-Filings System

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## ATTACHMENTS

| | |
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## GLOSSARY

| Term | Meaning |
|---|---|
| ARIMA | Auto-Regressive Integrated Moving Average |
| AQCC | Colorado Air Quality Control Commission |
| BA | Balancing Authority |
| BE | Beneficial Electrification |
| BEA | U.S. Department of Commerce Bureau of Economic Analysis |
| CAISO | California Independent System Operator |
| CDPHE | Colorado Department of Public Health and Environment |
| CEP | Clean Energy Plan |
| EIA | Energy Information Administration |
| ERP | Electric Resource Plan |
| GHG | Greenhouse Gas |
| PNM | Public Service Company of New Mexico |
| RAP | Resource Acquisition Period |
| RES | Renewable Energy Standard |
| RPS | Renewable Portfolio Standard |
| RTO | Regional Transmission Organization |
| RUS | Rural Utilities Service |
| SAE | Statistically Adjusted End-Use |
| SIP | State Implementation Plan |
| SPP | Southwest Power Pool |
| WEIM | Western Energy Imbalance Market |
| WEIS | Western Energy Imbalance Service |
| W&P | Woods & Poole Economics, Inc. |
| WAPA | Western Area Power Administration |

A: While the Commission need not consider New Mexico's RPS when evaluating Tri-State's Colorado ERP, Tri-State operates an integrated, interconnected, interstate generation and transmission system that must meet the legislative and regulatory requirements of all of the states in which it is located. Tri-State must ensure that its system and associated resources comply with Colorado's and New Mexico's relevant laws and regulations.

**Q: IS TRI-STATE'S 2020 ERP CONSISTENT WITH ALL STATE AND FEDERAL LAWS RELATED TO RENEWABLE STANDARDS?**

A: Yes. As described in Volume I, "Base Case and Alternative Scenario Comparison" and in Volume II Attachment 6-2 of the ERP, Tri-State is exceeding the requirements of both the Colorado RES and the New Mexico RPS.

## XIII. COSTS AND BENEFITS OF EARLY RETIREMENTS

**Q: HOW WERE THE ANNOUNCED EARLY RETIREMENT DATES OF CRAIG UNIT 1, CRAIG UNIT 2 AND CRAIG UNIT 3 DEVELOPED?**

A: The owners (Yampa Participants) of Craig Unit 1 will retire Craig Station Unit 1 by December 31, 2025, as is required by the current Colorado Regional Haze State Implementation Plan. The Yampa Participants also agreed to a September 30, 2028, retirement date for Craig Unit 2. December 31, 2029, was selected as the retirement date for Craig Unit 3 in order to meet carbon reduction goals in 2030.

**Q: DID TRI-STATE CONSIDER THE COSTS AND BENEFITS OF EARLY RETIREMENTS OF GENERATION RESOURCES?**

A: Yes. In all scenarios, including the base case, Tri-State modeled the previously announced early retirements of Escalante, Craig Unit 1, Craig Unit 2 and Craig Unit 3. In each scenario except the base case, Tri-State enabled modeling consideration of retirement of coal resources prior to their planned early retirement dates or, as applicable, prior to the end of their useful life. In the social cost of carbon scenario, Tri-State enabled modeling consideration of both coal and gas retirements prior to end of useful life or scheduled retirement date. Assumptions related to retirements, which varied by scenario, are outlined in Volume I "Base Case & Alternative Scenario Results" section of the ERP.

**Q: HOW DOES THIS ANALYSIS RELATE TO THE BENCHMARKING ANALYSIS YOU DESCRIBED EARLIER IN YOUR TESTIMONY?**

A: Whereas the benchmarking analysis is intended to provide information regarding the relative performance of Tri-State's resources compared to generic resources, it does not specifically consider early retirements. Instead, the benchmarking analysis informs the consideration of early retirements by providing information on generation units that may be underperforming.

## XIV. ASSESSMENT OF NEED FOR ADDITIONAL RESOURCES

**Q: PLEASE DESCRIBE TRI-STATE'S APPROACH TO ASSESSING ITS NEED FOR ADDITIONAL RESOURCES.**

A: Tri-State's assessment of the need for additional resources is driven by a number of factors, including early retirement of existing fossil units; Utility Members' load forecasts; RES/RPS requirements; potential for growth in demand-side management and energy efficiency; regulations addressing carbon emissions; implementation of beneficial electrification; and Tri-State's entry into an organized market.

**Q: PLEASE DESCRIBE TRI-STATE'S PLANNED RETIREMENTS OF EXISTING RESOURCES.**

A: Tri-State retired the Escalante Generating Station in November 2020. Tri-State has announced planned retirements of Craig Unit 1 by December 31, 2025, Craig Unit 2 by September 30, 2028, and Craig Unit 3 by December 31, 2029. Craig Unit 1 and Unit 2 are owned by the Yampa Participants, and the retirement decisions were made jointly by the participants.

**Q: PLEASE DESCRIBE THE IMPACT OF TRI-STATE'S LOAD FORECAST ON THE ASSESSMENT OF RESOURCE NEEDS.**

A: Tri-State's load forecast of peak demand and firm peak obligations, together with losses and reserve requirements, are compared to existing resources, while accounting for planned retirements and contract expirations, to determine system balance capacity needs.

BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

| | |
|---|---|
| Federal Power Act Section 202(c) | ) |
| Emergency Order: Tri-State | ) |
| Generation and Transmission | ) |
| Association, Platte River Power | ) |
| Authority, Salt River Project, | ) |
| PacifiCorp, and Xcel Energy | ) |

Exhibit to
Motion to Intervene and Request for Rehearing and Stay of
Public Interest Organizations

Exhibit 2-59:
Intertek Reliability Study

intertek
Total Quality. Assured.

# Update of Reliability and Cost Impacts of Flexible Generation on Fossil-fueled Generators for Western Electricity Coordinating Council

**WESTERN ELECTRICITY COORDINATING COUNCIL**
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**REPORT NO**
AIM 191210726-2-1

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**DATE**
12 May 2020



## List of Revisions

| Rev. | Date | Revision Details | Author |
|---|---|---|---|
| 0 | 12 May 2020 | Final Issue | N. Kumar |

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# 1 | Introduction

The addition of variable generation (VG) places new constraints and costs on conventional generation of power in utility systems, particularly due to an increase in the variability and uncertainty associated with VG. There is a need to include the change in reliability and cost of operating fossil-fueled power plants with operating patterns that include increased generator flexibility.

Fossil-fueled power plants operated in flexible mode are likely to have increased wear and tear on the equipment and/or reliability impacts that do not necessarily occur if the plants were run in baseload operation mode. This is particularly true for power plants designed for baseload operation. A power plant designed for baseload operation typically operates at full load for long periods of time between cold shutdowns. Critical components operate at design temperatures, with temperature imbalances which occur only at that load. Startups and shutdowns are infrequent, and the load ramp rates consistent, so fatigue damage is less of a concern.

Flexible or cycling operation, on the other hand, requires several different modes of operation: two-shifting, load following, and low load operation, as well as frequent startups (hot, warm, and cold), faster ramp rates, and more thermal cycles than originally designed for. Temperature imbalances may be exacerbated by operation at non-optimum, non-design loads. Temperature differences between components may cause flexibility issues and subsequent fatigue damage.

The Western Electricity Coordinating Council (WECC) and the Production Cost Model Data Work Group are seeking to update the estimate of the cost of flexible generation and reliability impacts on the conventional fossil-fueled generators for operation in calendar year 2030.

Intertek AIM (previously Aptech Engineering Services) had provided an estimate of increased wear and tear costs and reliability impacts to WECC [Intertek Project AES 11077831-2] and National Renewable Energy Laboratory (NREL) [Contract No. DE-AC36-08GO28308].[1]

In our previous study, Intertek AIM had organized the results by the following eight generator plant types in the following eight groups:

1. Small coal-fired sub-critical steam (35-299 MW)
2. Large coal-fired sub-critical steam (300-900 MW)
3. Large coal-fired supercritical steam (500-1300 MW)
4. Gas-fired combined-cycle plants (combustion turbine (CT)-steam turbine (ST) and heat recovery steam generators (HRSG)
5. Gas-fired simple cycle large frame (GE 7/9, N11, V94.3A, and similar types)
6. Gas-fired simple cycle Aero-Derivative CT (LM 6000, 5000, 2500)
7. Gas-fired steam (50-700 MW)
8. Retrofitted coal-fired steam (plants retrofitted to provide load following or regulation) – these plants should be parsed by size/type same as Types 1 through 7.

[1] https://www.nrel.gov/docs/fy12osti/55433.pdf

The primary task of the study included the estimation of "lower bound" cycling cost data for the above identified groups of generator plant types, including the following:

- Hot, warm, and cold start costs
- Baseload variable operations and maintenance (VOM) costs

Figure 1 was a key output of the analysis showing the spread of cycling-related costs.

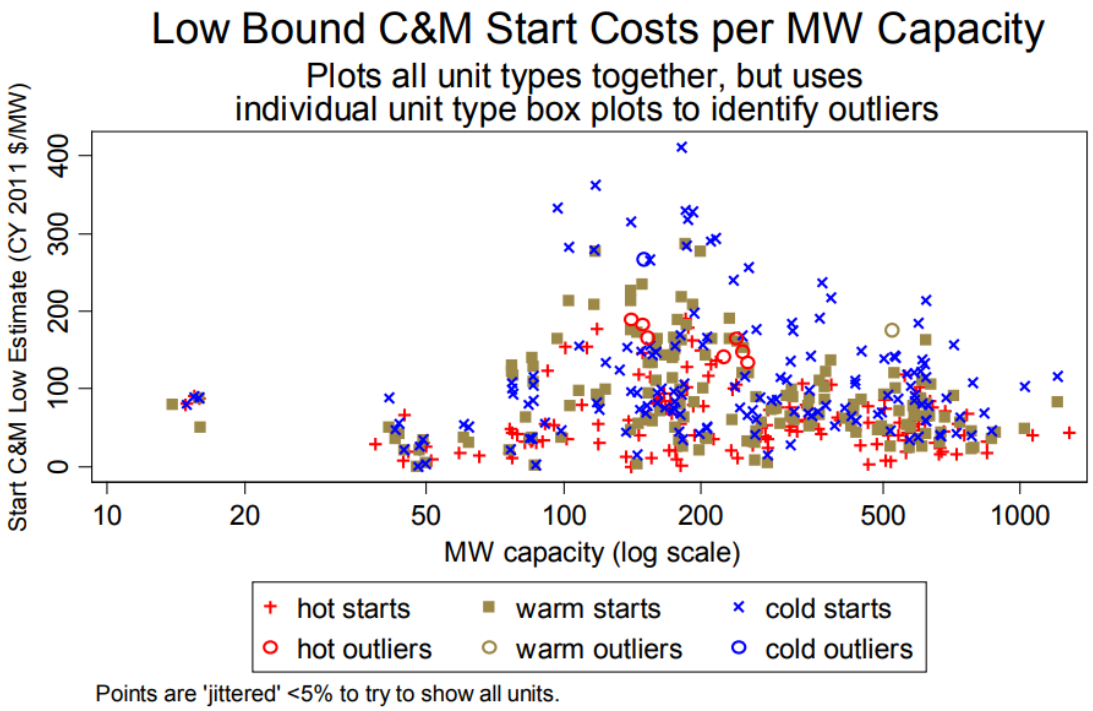



**Figure 1 — Lower Bound – Capital and Maintenance Start Costs per MW Capacity.**

## Background

Since Intertek AIM and WECC collaborated on this work in 2011, several changes have occurred with respect to power plant operating profiles and technologies. Further, different regions in the U.S. have witnessed different outcomes from the integration of VG.

A combination of market deregulation, increasing VG, changes in fuel prices, and other factors have forced operators to cycle aging fossil units that were originally designed for mainly base load operation. As shown in previous studies, all fossil generators can perform cycling operation, but the impact of cycling on wear and tear cost or damage and the reliability of the plants from the cycling differs from one unit to another (see figure 1).

Intertek AIM has performed evaluation of the evolving operating regime of several hundred power plants in the U.S.[2] As an example, Figure 2 shows the change in operating mode of the fossil generation fleet in California from 2005 to 2015. The change in operating profile is largely driven by the rapid increase in solar generation in the state. Solar generation in the state forces the natural gas fleet in California (about 40% of capacity) to operate with increased cycling. Fossil units are staying offline for more hours in 2015 compared to 2005, and when they are online, they typically ramp up to full load (as solar generation falls at night). There is also a trend of increased operating hours at lower loads in 2015 versus 2005.

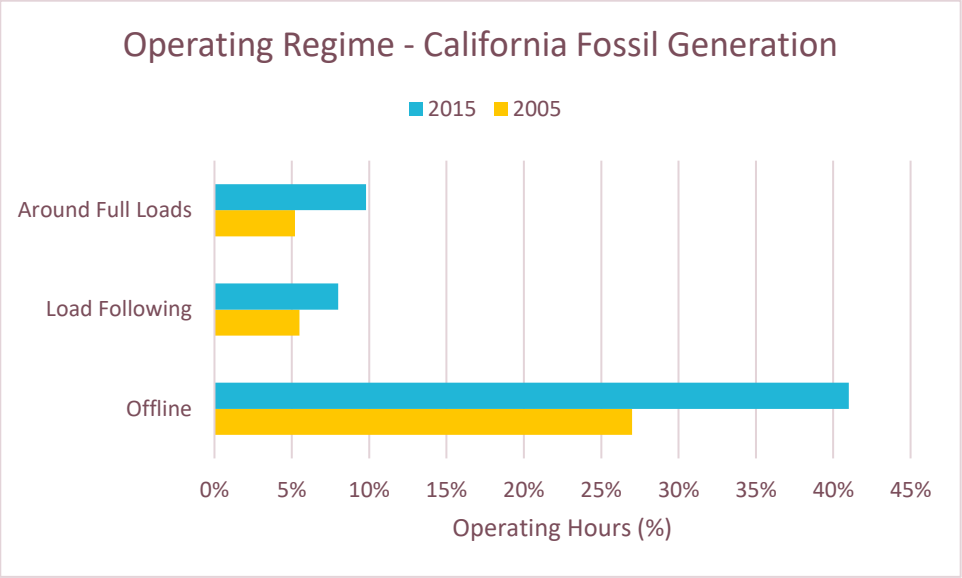



**Figure 2 — Operating Regime of California Fossil Generators (2005 vs. 2015).**

Characterizing fossil power generation impacts from large VG on the grid requires an understanding of the operating regime of the power plants. Further, the analysis should cover a long enough time horizon to account for the "time lagged" wear and tear damage on fossil generation equipment. When a power plant is relatively new, there is a much larger time lag between increased cycling and failures, compared to an older plant[3]

Flexible generation or cycling refers to the operation of electric generating units at varying load levels, including on/off and low load variations, in response to changes in system load requirements. Every time a power plant is turned off and on, the boiler, steam lines, turbine, and auxiliary components go through unavoidably large thermal and pressure stresses, which cause damage. This damage is made worse by the phenomenon we call creep-fatigue interaction. Creep and fatigue are terms commonly used in engineering mechanics. Creep is time-dependent change in the size or shape of a material due to constant stress (or force) on that material. In fossil power plants, creep is caused by continuous stress that results from constant high temperature and pressure in a pipe or tube occurring during

[2] Impact of Large-Scale Wind & Solar Integration on Existing Fossil Generation in United States, N. Kumar et al., 15th Wind Integration Workshop, Vienna (2016)
[3] "Power Plant Cycling Costs," N. Kumar et al. http://www.nrel.gov/docs/fy12osti/55433.pdf.

steady-state base load operation. Fatigue is a phenomenon leading to cracking and possible fracture (failure) when a material is under repeated, fluctuating stresses. In a fossil power plant, such fluctuating stresses result from large transients in both pressures and temperatures. The worst of these transients typically occur during cyclic operation. Because base load fossil units are designed to operate in the creep range, they experience increased outages when they are additionally subjected to cycling-related fatigue. The term creep-fatigue interaction suggests that the two phenomena (creep and fatigue) are not necessarily independent, but act in a synergistic manner to cause premature failure. In fact, materials behave in a complex manner when both types of stresses occur.

Relating this discussion to power plants, if an older, base loaded plant (that used to have three to six starts per year and is at 40 to 80% design life from creep damage) is now suddenly dispatched to operate at 50 starts per year, it may take only 2 to 6 years to cause component failures. Thus, while cycling-related increases in failure rates may not be noted in the first months, critical components will eventually start to fail. Shorter component life expectancies will result in higher plant equivalent forced outage rates (EFOR) and/or higher capital and maintenance costs to replace components at or near the end of their service lives. In addition, cycling increases may result in reduced overall plant life. How soon these detrimental effects will occur will depend on the amount of creep damage present and the specific types and frequency of the cycling.

As a power plant ages, the equipment degrades even though it is maintained and inspected and is unable to perform as well as brand new equipment. It becomes necessary to upgrade or replace degraded equipment to "new condition". For example, even though condensers are cleaned annually or more often, condenser retubing becomes necessary every 10 or 15 years. In other words, maintenance is necessary to minimize the effect of equipment degradation with age and operating regime. With cycling operation, some components face accelerated life degradation from the effects of aging and the off-design operations.

Capital expenses, as well as variable and fixed operations and maintenance (O&M) costs at a generating facility, can be analyzed to assess maintenance and equipment replacements at a power plant and determine the current condition. Costs associated with plant cycling and the impact of the cycling on reliability can also be gauged and quantified. Plants that have underspent on capital and/or O&M are likely to suffer with lower historical reliability or are at risk of future forced outages.

The unit's specific analysis results depend heavily on the regression analysis of the costs versus cycles and the unit signature data during cyclic operations including the range of all load changes. A comprehensive methodology to determine the cost associated with plant cycling has been discussed in recent renewable integration studies.

The increased incremental costs that are attributed to cycling are broken down into the following categories[4]:

1. Increases in maintenance and overhaul capital expenditures.
2. Forced outage effects including forced outage time, replacement energy, and capacity.

[4] Lew, D.; Brinkman, G.; Ibanez, E.; Florita, A.; Heaney, M.; Hodge, B.-M.; Hummon, M.; Stark, G.; King, J.; Lefton, S.A.; Kumar, N.; Agan, D.; Jordan, G.; Venkataraman, S. (2013). The Western Wind and Solar Integration Study: Phase 2. NREL/TP-5500-55588. Golden, CO: National Renewable Energy Laboratory. Accessed May 2, 2014: http://www.nrel.gov/docs/fy13osti/55588.pdf.

3. Efficiency, both long-term losses as well as operational losses associated with startups and low/variable loads.
4. Cost of startup fuel, auxiliary power, chemicals, and extra startup manpower.

## Report Goals

WECC's Production Cost Model Data Work Group required Intertek AIM to update the cost and reliability impacts estimated in the 2012 study for modes of operation in calendar year 2030.

The following technical approach was used to quantify the wear and tear cost impacts:

- Characterize historical operations of thermal units within WECC.
- Evaluate and control for recent and projected power plant Capital Expenditures (CapEx) and Operating Expenditures (OpEx)
- Calculate changes to cycling duty and the potential impacts on wear and tear costs, as well as reliability impacts.

The results presented in this report include the following generation types:

1. Small coal-fired sub-critical steam (35-299 MW)
2. Large coal-fired sub-critical steam (300-900 MW)
3. Large coal-fired supercritical steam (500-1300 MW)
4. Gas-fired steam (50-700 MW), includes both supercritical and subcritical technologies
5. Gas-fired simple cycle large frame (GE 7/9, N11, V94.3A, and similar types)
6. Gas-fired simple cycle Aero-Derivative CT (LM 6000, 5000, 2500). New data set to include, New Fast Start Gas Turbines – Aero-Derivative (LMS 100 and similar)
7. Gas-fired combined-cycle plants (CT-ST and HRSG) – Conventional[5]
8. Gas-fired combined-cycle plants (CT-ST and HRSG) – High Efficiency Gas Turbines (H Class and Similar)
9. Gas-fired combined-cycle plants (CT-ST and HRSG) – Fast Start
10. Gas Reciprocating Engines

Intertek AIM has limited the sample size of units to the Western Interconnect where reasonable; however, we have included other U.S.-based power plants if sample size is small.

[5] F-Class based machines. F-class turbines are typically in the 170-230 MW range. Products include GE's 7F.03-.05 models, Siemen's SGT6-5000F, and Mitsubishi Hitachi's M501F

The results of the projected 2030 cost of cycling and reliability impacts will be provided in the following format:

- **Hot, Warm, and Cold Start Costs**

  Costs per start for hot, warm and cold starts (2020$).

  **Physical Constraints**: Intertek AIM will also provide typical ramping capabilities, minimum up and down time, startup time for the different generation technologies, and the corresponding cost impacts.

- **Load Following Costs**

  Costs for various load following modes – mild, significant, and operation at minimum load (2020$).

  Minimum load operation to be evaluated may be at approximately 80%, 50%, and 30% of maximum load. Generation technologies that are unable to operate below any minimum load operation described above will be noted. These costs will inherently include all cycling-related costs (except forced outage costs).

  **Physical Constraints**: Ramping capabilities at various low loads will be listed, including cost impacts.

- **Base-loaded Variable O&M Costs**

  Intertek AIM determines the cycling-related O&M cost (listed above) and subtracts that from the total O&M costs to generate a baseload VOM cost. These costs assume a power plant running at steady load without any on/off cycling. This will ensure no double counting of VOM costs in WECC's production cost modeling.

- **Reliability Impacts**

  While cycling, increases in failure rates may not be noted immediately, critical components will eventually start to fail. Shorter component life expectancies will result in higher plant EFOR and/or higher capital and maintenance costs to replace components at or near the end of their service lives. Intertek AIM will provide the expected "lower-bound" increase in EFOR (in added percentage for a single year) due to each cycle type.

# 2 | Flexible Generation Costs and Reliability Impacts

Calculated cycling costs for typical load cycles of any power plant unit are recorded by Intertek AIM as the total present-valued future cost of the next "incremental" cycle.

These numbers are best estimates based on the assumption that the overall amount of cycling (i.e., equivalent hot start (EHS) per year) continues at no more than 75% of the level of past operations. If the amount of cycling of a given unit increases dramatically, the cost per cycle would also increase due to nonlinear creep-fatigue interaction effects.

However, if CapEx and OpEx spend is reduced for any reason, such as an impending retirement of the asset, then the net cost of cycling is reduced. The reduced spend will manifest as reduced reliability. Such trends have been observed at other sites assessed by the author.[6]

## Basic Premise

Maintenance requirements are based on an assessment of hours of operation or cycling of a unit (besides any reactionary events). Major costs for each inspection are for labor, consumables, and capital replacement parts. Labor is the extra manpower needed to perform the inspection. The consumables are material which will be used during the inspection or maintenance activity, such as gaskets, welding products, etc. Capital replacement parts are the parts that are examined for corrosion and wear during each inspection. Generally, the capital replacement costs dominate the overall ratio of costs, as this is primarily to counter for the life shortening effects of aging or additional cycling.

Cost is one of the key factors influencing the choice of fuels and technologies used to generate electricity. Capital, maintenance, operating, and financing costs often vary significantly across technologies and fuels. In addition, regional differences in construction, fuel, transmission, and resource costs mean that location also matters. Because electricity prices differ throughout the day, the timing of a plant's output affects its cost recovery.

The underlying premise of Intertek AIM's approach is that cycling directly causes a significant proportion of annual non-fuel unit costs. For economic modeling, the independent cycling-related variable was taken to be equivalent hours of operation.

### Costs per Start

The desired result is an estimate of the cycling cost elements combined to determine the effect of an additional equivalent start. Intertek AIM's methodology brings all future forecasted costs to their present value using the client's discount rate, cost escalation factor (or simply inflation rate), and aging effects.

[6] Cochran, Jaquelin, Debra Lew, and Nikhil Kumar. Flexible Coal: Evolution from Baseload to Peaking Plant. NREL, 2013 https://www.nrel.gov/docs/fy14osti/60575.pdf

The present value of future wear and tear cycling costs for the plant equipment is the sum of two components: added costs and accelerated costs:

- Specifically, the first component, adding costs, is the cost of extra cycling-related maintenance necessary to avoid shortening of the component's life caused by an additional start.

- The second component, accelerated costs, is the cost of "moving up" future maintenance costs in time (i.e., maintenance costs occur sooner) caused by adding one "start". Adding a "start" to a unit's operation will cause the time required before maintenance is needed to decrease. Thus, this second component represents the present value of the acceleration of costs incurred for ordinary maintenance costs due to an additional start, especially overhaul costs and other large non-annual costs.

Further, it is important to highlight the impact of life shortening as a result of increased flexible operation. Increased cycling can have a significant life-shortening impact on certain units. This cost element can be significant for units that are near their end-of-life, but less important in cases of planned retirements. Note that as long as capital and maintenance expenditures are made to counter cycling effects, this cost element will be small compared to such costs as maintenance and extra fuel. In other words, the cost of maintenance is essentially countering the effects of life shortening over time.

It is important to note that since not all subsystems have the same life expectancy; targeted spending patterns for critical subsystems are required. Intertek AIM looks at both total spending and spending patterns to determine if current and projected critical subsystem spending is enough to maintain efficiency and reliability.

Table 1 provides definitions of costs included in the wear and tear estimates.

**Table 1 — Definitions of the Cycling-related Costs**

| | Cost Includes | Cost Excludes |
|---|---|---|
| Cost of O&M | • Operator non-fixed labor<br>• General engineering and management cost (including planning and dispatch)<br>• Maintenance and overhaul maintenance expenditures (preventative and scheduled) for boiler, turbine, generator, air quality control systems, and balance of plant key components | • Fixed labor<br>• Fixed maintenance and overhaul maintenance expenditures for boiler, turbine, generator, air quality control systems, and balance of plant key components<br>• Preventative maintenance and routine maintenance on auxiliary equipment like buildings, HVAC, etc. |
| Cost of Capital Maintenance | • Overhaul capital maintenance expenditures for boiler, turbine, generator, air quality control systems, and balance of plant key components | • Replacement due to obsolescence<br>• Preventative maintenance and routine maintenance on auxiliary equipment like buildings, HVAC, etc. |

## Damage Modeling & Cost Estimation

Intertek AIM's full comprehensive top-down and bottom-up methodologies for estimating cycling costs provide better and high confidence estimates, which require extensive cost and operational data. That approach models the relationship between total cycling costs (wear and tear, EFOR, startup costs, etc.) and historical cycling operations for the unit or plant. To set up and run a complete cost of cycling program, we require 8 to 10 years of cost and hourly megawatt and plant reliability data as a minimum. In the absence of these required considerable data, we have found that a reasonable (though less accurate) method is to "benchmark" or measure the cost estimates from those units against those from similar units previously analyzed for which we have completed the more rigorous cost estimate methodology with detailed information.

Figure 3 shows the overview of our process to estimate lower bound cycling costs.

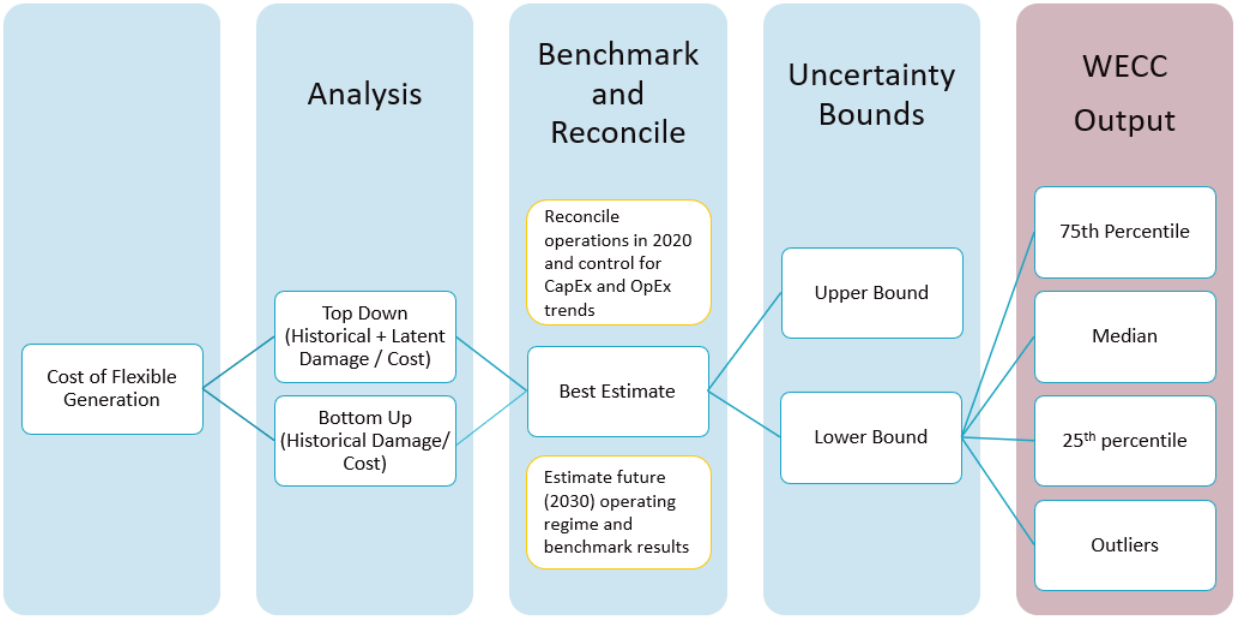



**Figure 3 — Lower Bound Cost Estimation Methodology.**

To establish the reference unit cycling costs, we used our top-down methodology. We used elaborate statistical models to develop "lower bound" estimates of the total unit equipment damage costs due to cycling, which include the incremental wear and tear costs and the capitalized maintenance and O&M costs in the full-blown, top-down cost of cycling analysis. The results of these statistical analyses are then used as benchmarks for calculating the cycling costs presented in this report.

The control variables in our benchmarking approach are listed below:

- Size — We defined size by the megawatt capacity of generators for the unit (for combined-cycle units, we sum the capacities of the ST and gas turbine(s)).



- Cycling rate and age — These factors account for unit age and for differing annual and cumulative rates of cycling damage expressed in EHS, as measured using Intertek AIM's damage algorithm – Loads Model[7].
- Vintage and design characteristics — Some technologies are better suited to operate flexibly (example, gas turbines or reciprocating engines).
- Typical cycle damage ratio (in units of EHS per cycle) — The ratio of the average damage for the subject unit's start or load follow to that of the benchmark unit; again, as estimated using the Loads Model, the cycle ratios for each start type (hot, warm, and cold) and load follow are considered, along with typical load follows.
- Annual plant maintenance costs — Plant maintenance and capitalized maintenance costs of benchmarked units were compared to the top-down reference unit costs.
- Reliability — Flexible operation, as well as aging of equipment, influence reliability.

## Operating Profile of Different Generation Technologies

An important step in estimating cycling costs and reliability impacts is to characterize the operating regime of the 10 groups of generation technologies. The next series of charts shows the operating regime of the coal steam and combined-cycle generation technologies over a 20-year horizon. Highlights from the analysis are:

- On average, the coal steam units have not witnessed increases in on/off cycling; however, they are operating with increased load following. Figures 4 and 5 highlight the operation of the sample of subcritical coal units within WECC. Evidently both the large and small coal units are operating more hours at lower loads in the recent years, and while the number of starts has not trended higher, when the units do go offline, they stay off for longer periods (cold starts).
- Simple cycle CTs continue to perform as peaking units, with low capacity factors. The generation peaks in the summer months as expected and shown in Figure 6.
- The combined-cycle fleet, with lower natural gas prices and a growing share of the overall grid capacity have transitioned to more baseload operation. Figure 7 shows the annual starts for a sample of conventional combined-cycle, newer high efficiency and fast start combined-cycle units.

[7] An EHS is Intertek AIM's unit of cycling intensity. One normal hot start and shutdown cycle would produce about one EHS. One abrupt hot start with especially damaging ramp rates and other load range characteristics would produce well over one EHS, as would most warm starts and all cold starts. The usually more numerous load follow cycles each typically produce a small fraction of an EHS.

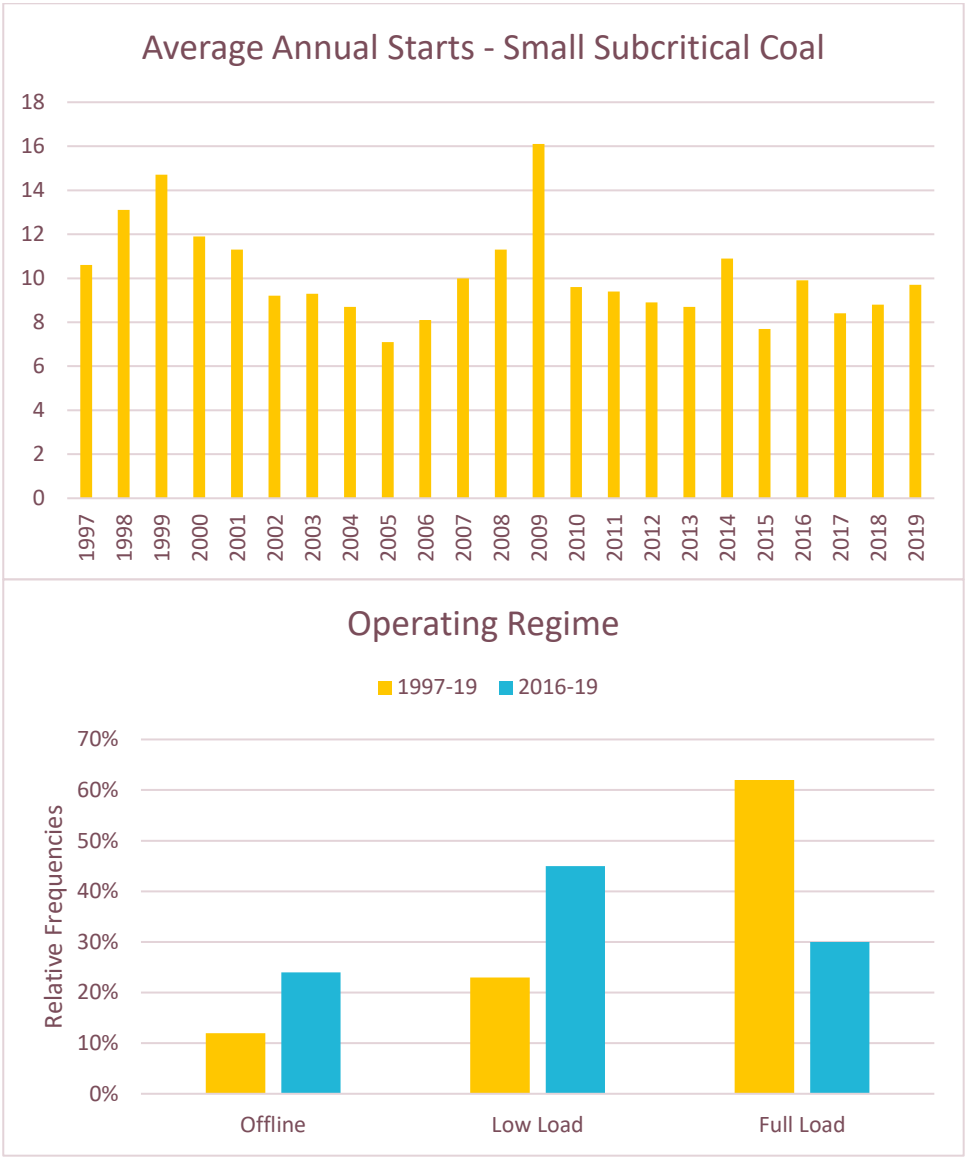



**Figure 4 — Small Subcritical Coal (<300 MW) Operating Regime.**

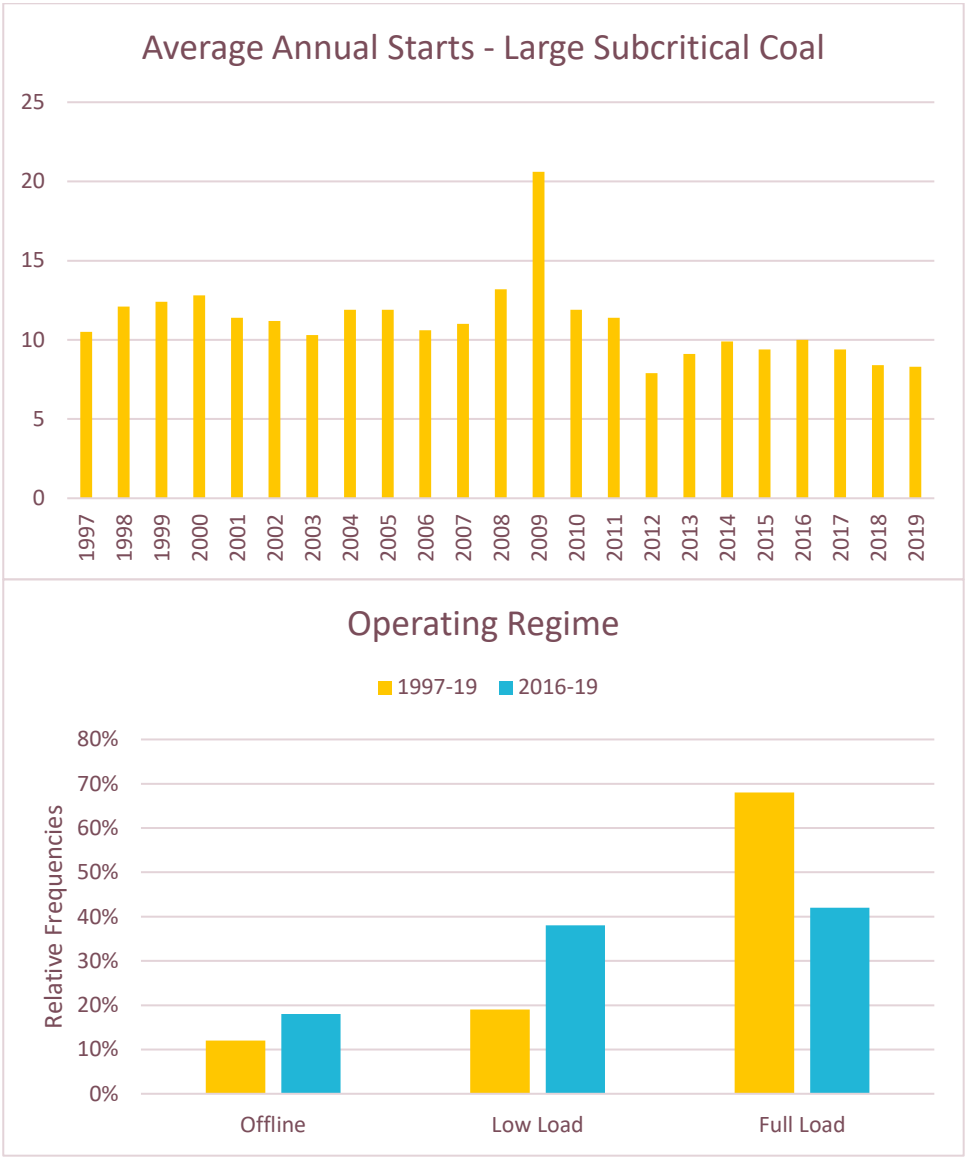



**Figure 5 — Large Subcritical Coal (>300 MW) Operating Regime.**

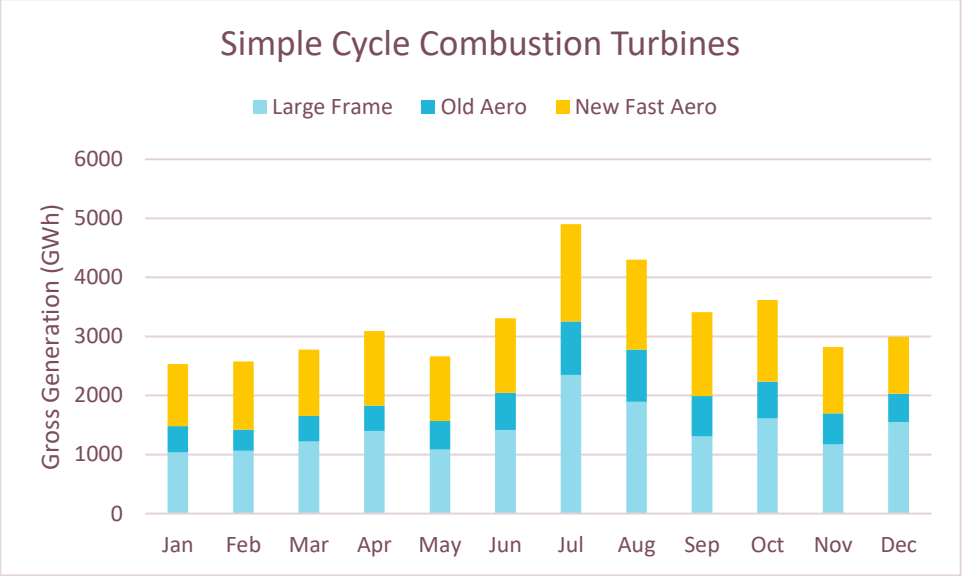



**Figure 6 — Simple Cycle CT Monthly Operating Regime.**

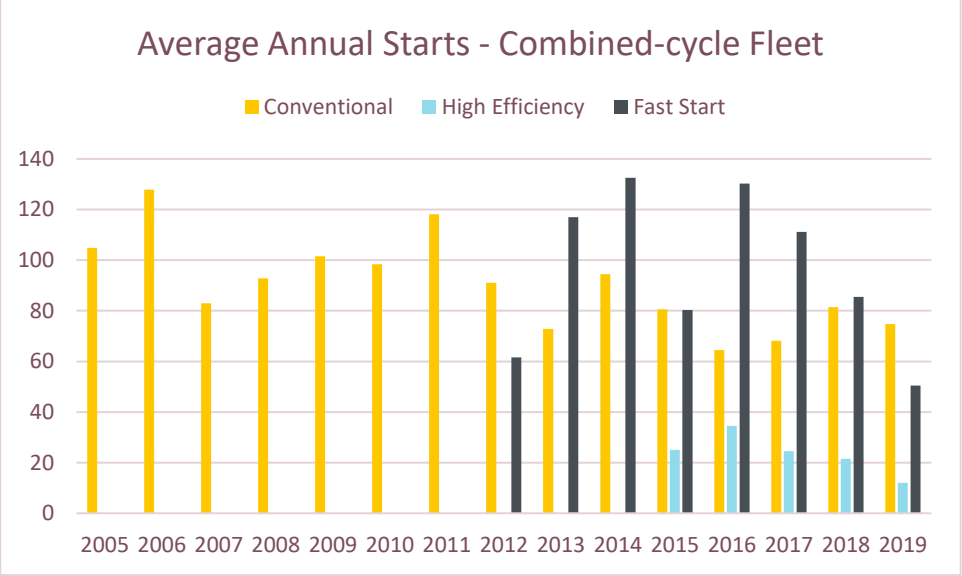



**Figure 7 — Annual Starts – Combined-cycle Fleet.**

## Flexible Generation Impacts and Results

Power plant operations that start, stop, cycle, two shift, base load, and operate above a unit's rating have a quantifiable impact on component life and on total associated unit operating costs. The true costs of cycling and low load operations are often not known or not well understood because of the complex effects of these operations on additional capital and/or maintenance spending requirements, increased EFOR, increased heat rate, and reduced life effects.

Figure 8 shows a risk chart from a small sample of units that show a relation between cycling and forced outage rates. To help reduce the clutter in the chart, some key units have been highlighted to illustrate the impact of cycling on forced outage rates for different design units[8].

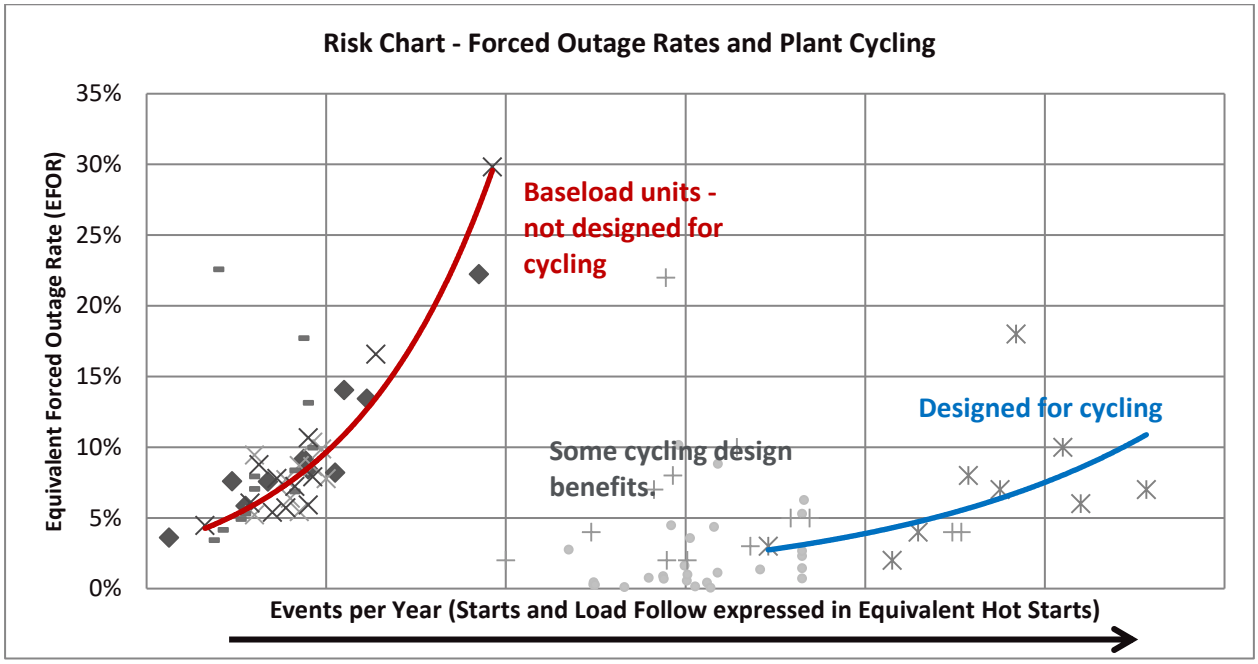



**Figure 8 — Flexible Generation and Reliability Impacts.**

Even when a unit is thought to be properly designed for cycling, there are external effects in the balance-of-plant design, water chemistry, etc., that make some units more susceptible to cyclic damage than others.

Another risk factor for an aging fleet of fossil generators is High Impact Low Probability (HILP) events. With increased cycling and an aging plant, operators of older assets, conventional steam as well as older combined-cycle units, are putting the units at increased risk of increased forced outages and HILP events. Older units have a much higher chance of experiencing HILP-related forced outages. Figure 9 shows hazard rates for aging power plants. Intertek AIM analyzed NERC GADS data and defined a HILP as a full forced (i.e., unplanned) outage greater than 350 hours.[9]

[8] Impact of plant cycling on availability, N. Kumar et al., ASME Power 2015, POWER2015-49359
[9] Impact of Aging on Power Plant Reliability, N. Kumar and P. Besuner, Intertek Engineering Technical Paper 214

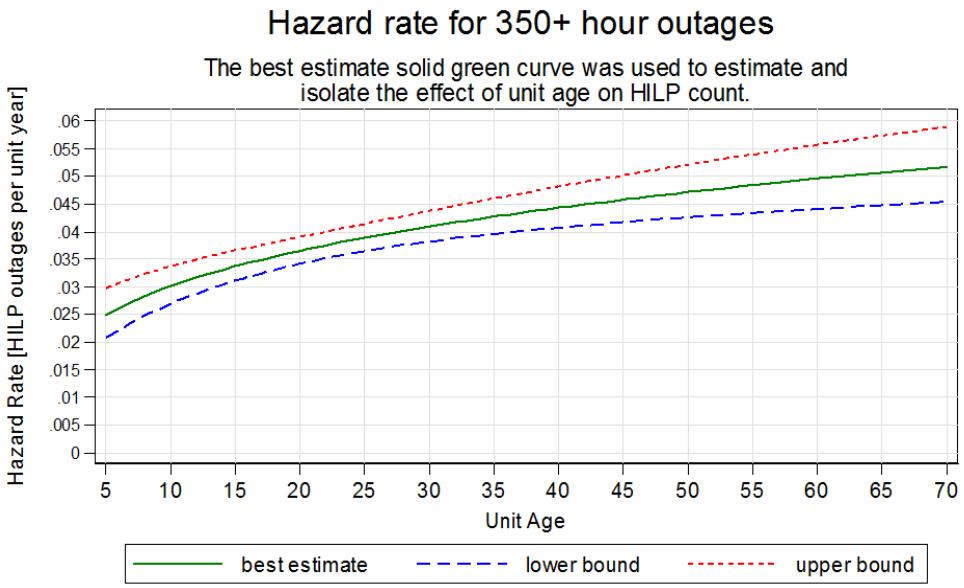



**Figure 9 — Hazard Rate for HILP Outages.**

Costs associated with plant cycling and the impact of the cycling on reliability can also be gauged and quantified. As a power plant operates with increased cycling and ages, the equipment degrades even though it is maintained and inspected and is unable to perform as well as brand new equipment. It then becomes necessary to upgrade or replace degraded equipment to "new condition."

Increased maintenance spend is necessary to minimize the effect of equipment degradation with age and changing operating regime. Plants that have underspent on capital and/or O&M are likely to suffer lower historical reliability or are at greater risk of future forced outages. As discussed earlier, Intertek AIM assessed the existing fleet operations within WECC to estimate accumulated cycling damage, and then benchmarked cost of flexible generation to reference units in our database. Over time, most North American operators have tended to minimize O&M spend.

Figure 10 shows the historical trend of real O&M for all plants and weighted by generation has decreased from 1990-2005 and has leveled out in recent years. Highlights of our analysis are discussed below: [10]

- While O&M spending is levelling off, capital costs are much higher than any other costs covered in our analysis. Essentially, even with extensive maintenance, the performance of the equipment will deteriorate over time to the point where it must be replaced.
- Coal power plant O&M has not been very high but there are some signs of increased coal O&M among the oldest plants. This tendency to keep O&M costs down for coal plants may also explain Intertek AIM's observation and analysis of increased forced outages with age.
- Combined-cycle units tend to have lower O&M spend, particularly in recent years.

[10] Power Plant O&M Spend in U.S. – Trends and Impact, N. Kumar & P. Besuner Intertek Technical Paper 305

- There are observed variations in O&M costs by state. California is an exception to low overall western state O&M costs, with moderately high O&M spending; but well below that of some of the highest O&M states in the U.S.

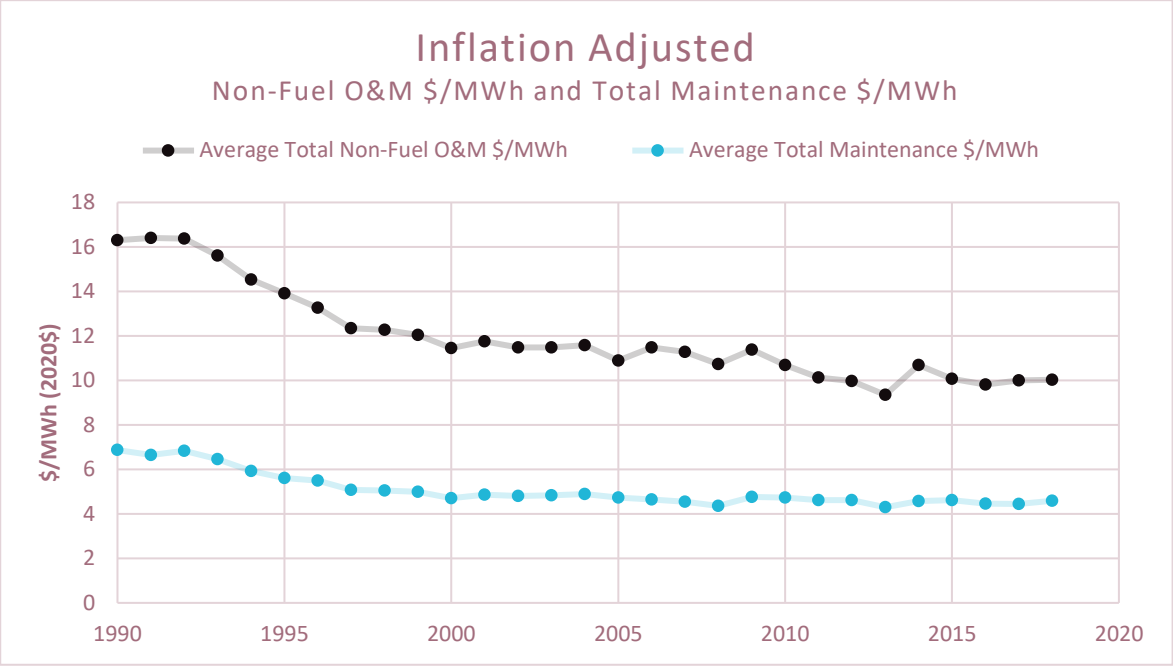



**Figure 10 — Historical Non-fuel O&M Spend.**

Finally, we referenced the U.S. Energy Information Administration (EIA) Annual Energy Outlook 2020 to forecast likely operating regime of the various fossil generation technologies in 2030[11].

The general trend discussed by the EIA, and our own assessment forecasts that:

- While there will be additional coal generation retirements by 2030, the remaining higher efficiency (thermal or economical) coal units will tend to operate similar to how they operate in 2016-2019 (Figures 4 and 5). However, these units are likely to suffer from lower O&M spend, increased offline hours, and deterioration of reliability as these units age.
- Simple cycle CTs and reciprocating engines are designed for cycling operation, and the operating profile will not differ significantly in 2030. Also, by definition, a majority of the VOM spend on these units is associated with cycling operation, which is reflected in our results.
- Conventional combined-cycle units would have accumulated several thousand hours of operation, as these units continue to operate more baseload. By 2030, several of these units would be over 25 years old, with competition from newer higher efficiency units, and therefore likely to operate with more on/off cycling. Per the EIA, "The currently most common combined-cycle units, with their

[11] https://www.eia.gov/outlooks/aeo/



lower efficiency, and the new single-shaft (1 x 1 x 1 configuration) combined-cycle units decline in utilization as a group, from 56% in 2020 to 36% by 2035".

- Fast start combined-cycles will see modest increase in on/off cycling, while the higher efficiency combined-cycle fleet will predominantly operate as they do now.

**Results**

Table 2 shows the physical constraints and capabilities of the ten (10) generation types analyzed:

- As expected, the simple cycle aeroderivative CTs and the reciprocating engines provide significant flexibility, with fast ramping capabilities and relatively short down times. Reciprocating engines have extremely fast ramp rates and can get up to full load at a ramp rate of 50% (as a percent of Gross Dependable Capacity (GDC)) per minute. Large frame CTs are not quite as flexible as aero derivative machines.
- Coal units have improved the low load capabilities, and more so on the larger subcritical coal units. Coal steam units are limited in terms of gas/oil support availability and/or number of mills in operation at low loads. Larger units have been able to improve low load operation from about 50% in the past to about 35-40% minimum load (as a percent of GDC). Coal units are also less flexible in terms of startup times and up times. Some units have been transitioning to sliding pressure operation, which may limit ramping response.[12]
- The median age of operating gas steam units is over 55. Most of the units in WECC are subcritical and have low capacity factors (<30%). Typically, these units perform no more than 40 starts a year and are utilized infrequently. The units can operate at low loads (around 20-30%) for extended periods of time but are not as efficient and used sparingly. These units are also operated with ramp rates that are significantly higher than coal steam units.
- Combined-cycle units typically have a minimum emissions compliance load, which limits the operating range. Multiple gas turbine configuration on these units lend increased flexibility in operation. Some of the new higher efficiency combined-cycle units are, however, in 1x1 configuration and operate mostly baseloaded. The ST is often a limiting factor for high ramp rates, and unless the plant is designed for cycling operation (e.g., bypass system), the units tend to have some limitations in terms of flexibility.
- Fast start combined-cycle units have HRSGs with a Benson® high pressure section or are single-pressure non-reheat units that minimize damage on the components. These units also might take advantage of the shutdown purge sequence (in compliance with NFPA® 85) to improve startup times.
- The high efficiency combined-cycle units can achieve efficiencies in excess of 60%. These units are typically constrained on ramp rates as well as low loads.

The values presented in Table 2 are for typical power plants and do not include units that may have been retrofitted or best in class.

[12] https://www.babcockpower.com/wp-content/uploads/2018/02/constant-and-sliding-pressure-options-for-new-supercritical-plants.pdf

## Table 2 — Capabilities and Physical Constraints of Fossil Generators

| Unit Types | Coal - Small Sub Critical | Coal - Large Sub Critical | Coal - Super Critical | Gas - Steam | Gas - Large Frame CT | Gas - Aero Derivative CT | Typical CC [GT+HRSG+ST] | High Eff. - CC [GT+HRSG+ST] | Fast Start - CC [GT+HRSG+ST] | Gas - Recip. [per Engine] |
|---|---|---|---|---|---|---|---|---|---|---|
| **Time (min)** | | | | | | | | | | |
| **Minimum Up Time** | 720 | 720 | 1440 | 120 | 60 | 60 | 120 | 120 | 60 | 30 |
| **Minimum Down Time** | 360 | 480 | 480 | 240 | 60 | 30 | 360 | 480 | 360 | 15 |
| **Startup Ramp Rate (%GDC/min)** | | | | | | | | | | |
| Typical - almost no diff. by start type | 2.0% | 3.5% | 3.5% | 10.0% | 10.0% | 90.0% | 6.0% | 5.5% | 8.0% | 95.0% |
| **Turndown Ramp Rate (%GDC/min)** | | | | | | | | | | |
| Don't see significant changes in rates for level of turndown. However, some steam units use sliding pressure. | 5% | 8% | 8% | 20% | 15% | 90% | 10% | 10% | 15% | 95% |
| **Minimum Load (% GDC)** | | | | | | | | | | |
| **Typical** | 40% | 35% | 45% | 20% | 50% | 50% | | | | - |
| **1x1** | | | | | | | 48% | 48% | 48% | |
| **2x1** | | | | | | | 25% | 25% | 25% | |

Tables 3 and 4 below present the lower bound cycling cost results for the ten (10) unit types for projected operations and annual spend in 2030. As with our analysis in 2012, it should be emphasized that there are large variations in costs between individual units of each type, and that the results provided by Intertek AIM are *low bounds*[13].

All cost numbers in this report have been adjusted for calendar year 2020$.

## Use of the generic lower bound costs, without accounting for actual unit operations and spend can result in significant under/over estimation of power plant cycling costs.

Table 3 presents the typical load following costs for three different operating regimes: mild load change (20% of GDC); typical load change (for each unit type); and minimum load operation. Figure 11 presents the same information in a graphical form. The load following costs are not significantly impacted by modest changes to ramp rates. In our assessment for load follow operation, an increase of 25% will have no measurable increase in costs. However, doubling of current ramp rates on the steam units (limited by design) will result in increased costs as indicated in Table 3. For the gas turbine-based technologies, the original equipment manufacturer limits ramp rate capabilities, and typically there is little leeway for operators to increase these rates (without control upgrades, or retrofits).

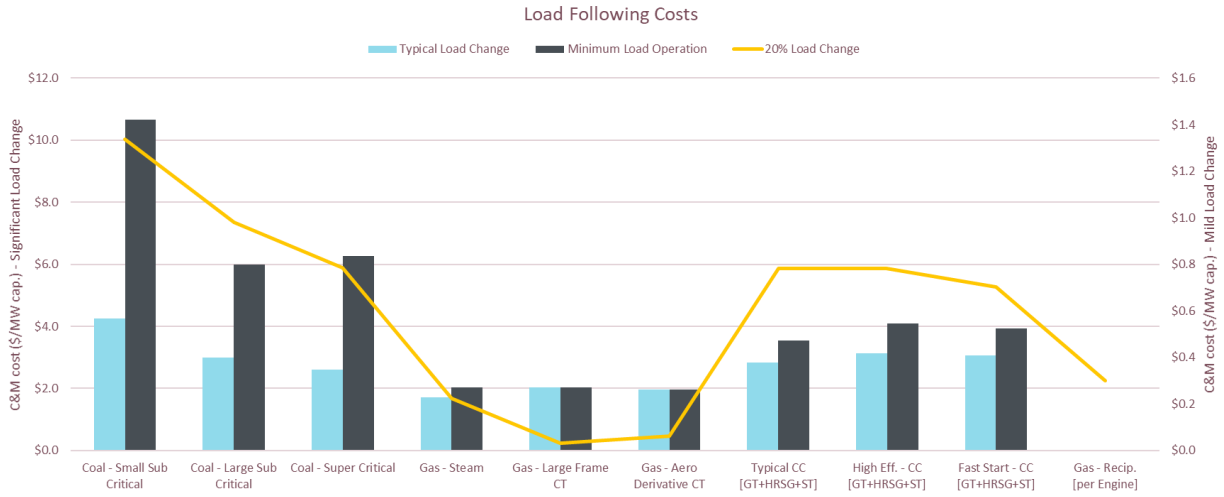



**Figure 11 — Load Following Costs.**

**Note: Mild load change costs are shown on the secondary y-axis.**

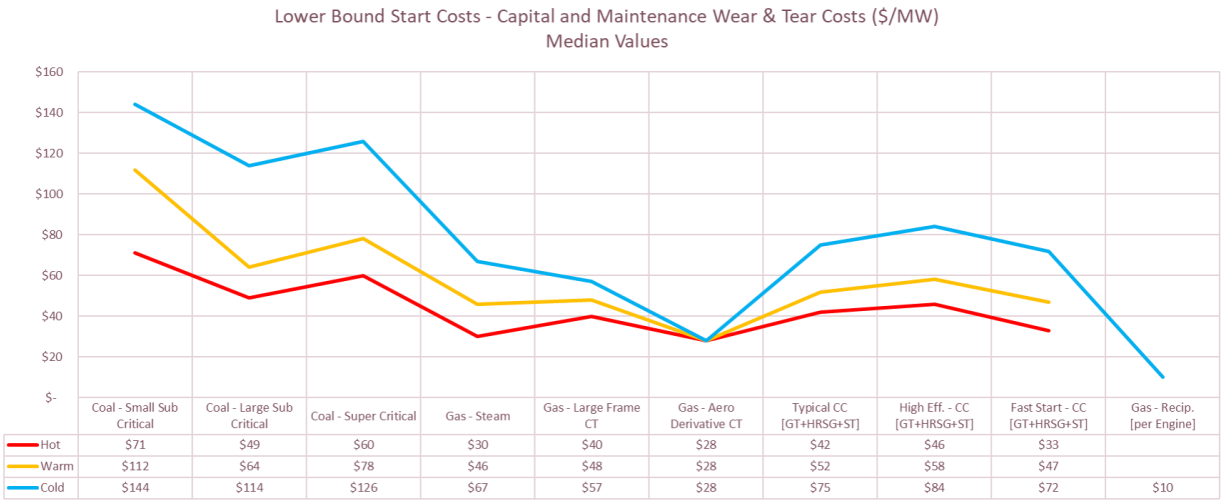
[13] Care should be taken to implement the lower bound cycling cost. For example, if a unit goes through 200 starts per year and the start cost is underestimated by $1,000/start, then the annual cost of this erroneous number can be significant. Moreover, if this unit is indeed cycled on/off more often due to the lower cost estimate, then it would accumulate damage at a significantly higher rate.

## Table 3 — Projected 2030 Load following cost estimates (lower bound, 2020$)

| Unit Types | Coal - Small Sub Critical | Coal - Large Sub Critical | Coal - Super Critical | Gas - Steam | Gas - Large Frame CT | Gas - Aero Derivative CT | Typical CC [GT+HRSG+ST] | High Eff. - CC [GT+HRSG+ST] | Fast Start - CC [GT+HRSG+ST] | Gas - Recip. [per Engine] |
|---|---|---|---|---|---|---|---|---|---|---|
| **Typical Load Follows Data** | | | | | | | | | | |
| **-C&M cost ($/MW cap.) - 20% Load Change** | | | | | | | | | | |
| **Median** | 1.34 | 0.98 | 0.78 | 0.22 | 0.03 | 0.06 | 0.78 | 0.78 | 0.70 | 0.30 |
| **~25th_centile** | 0.76 | 0.56 | 0.61 | 0.14 | 0.02 | 0.04 | 0.37 | 0.37 | 0.33 | 0.25 |
| **~75th_centile** | 1.54 | 1.24 | 0.95 | 0.27 | 0.05 | 0.14 | 0.90 | 0.90 | 0.81 | 0.40 |
| **-C&M cost ($/MW cap.) - Typical Low Load** | | | | | | | | | | |
| **Median** | 4.26 | 2.99 | 2.61 | 1.70 | 2.03 | 1.96 | 2.84 | 3.13 | 3.06 | |
| **~25th_centile** | 2.44 | 1.71 | 2.02 | 1.04 | 1.20 | 1.31 | 1.33 | 1.47 | 1.44 | |
| **~75th_centile** | 4.90 | 3.79 | 3.17 | 2.06 | 3.57 | 5.28 | 3.29 | 3.61 | 3.54 | |
| **-C&M cost ($/MW cap.) - Minimum Load** | | | | | | | | | | |
| **Median** | 10.66 | 5.98 | 6.27 | 2.02 | 2.03 | 1.96 | 3.55 | 4.08 | 3.92 | |
| **~25th_centile** | 6.10 | 3.42 | 4.86 | 1.23 | 1.20 | 1.31 | 1.67 | 1.91 | 1.84 | |
| **~75th_centile** | 12.26 | 7.57 | 7.61 | 2.45 | 3.57 | 5.28 | 4.11 | 4.72 | 4.53 | |
| | | | | | | | Doesn't include a GT start | | | |
| **Ramp Rate Effect** | | | | | | | | | | |
| **-Typical Range X 1.25** | - | - | - | - | - | - | - | - | - | - |
| **-C&M cost ($/MW cap.) - Typical Range X 2** | | | | | | | | | | |
| **Median** | 6.40 | 5.38 | 4.70 | 2.13 | | | | | | |
| **~25th_centile** | 3.66 | 1.97 | 2.33 | 1.19 | | | | | | |
| **~75th_centile** | 7.35 | 11.36 | 9.51 | 2.68 | | | | | | |

Table 4 below presents the updated cost of starts (and stops) and non-cycling baseload VOM costs for the different generation technologies. Figure 12 presents the start cost per megawatt capacity for each of the generation types graphically (median values). As a reminder, these are 2030 projected costs in 2020$.

Table 5 presents the expected increase in EFOR (in added percentage for a single year[14]) due to each cycle type. Baseload or cycling operation both cause forced outages at plants. Cycling operation can accelerate EFOR, especially on a baseload design power plant. Countering the impact on reliability can only be done by replacing or repairing equipment, that is, increased CapEx and OpEx. This is evident in the results of this study. With lower spending, there is a general trend of increased cycling-related reliability impact. Further, in our experience, we know that cycling-related increases in failure rates may not be noted immediately, but critical components will eventually start to fail as the plant accumulates cycling-related damage. Since a vast sample of the units in 2030 will have accumulated several thousand operating hours, the forecasted impact on reliability is valid, and perhaps conservative considering lower O&M spending.




| | Coal - Small Sub Critical | Coal - Large Sub Critical | Coal - Super Critical | Gas - Steam | Gas - Large Frame CT | Gas - Aero Derivative CT | Typical CC [GT+HRSG+ST] | High Eff. - CC [GT+HRSG+ST] | Fast Start - CC [GT+HRSG+ST] | Gas - Recip. [per Engine] |
|---|---|---|---|---|---|---|---|---|---|---|
| Hot | $71 | $49 | $60 | $30 | $40 | $28 | $42 | $46 | $33 | |
| Warm | $112 | $64 | $78 | $46 | $48 | $28 | $52 | $58 | $47 | |
| Cold | $144 | $114 | $126 | $67 | $57 | $28 | $75 | $84 | $72 | $10 |

**Figure 12 — Typical Lower Bound Load Following Costs (Median Values).**

[14] For example, Table shows a median (lower bound) EFOR impact of 0.0194% per hot start for small sub critical coal units. Assume that the EFOR = 2% for some future year and the Unit typically sees 10 hot starts annually. If 5 additional hot starts are imposed, the EFOR will be raised to 2.097% (2 + 0.00194*5) for a single near-future year.

## Table 4 — Projected 2030 Start Cost and Baseload VOM Costs (Lower Bound, 2020$)

| Unit Types | Coal - Small Sub Critical | Coal - Large Sub Critical | Coal - Super Critical | Gas - Steam | Gas - Large Frame CT | Gas - Aero Derivative CT | Typical CC [GT+HRSG+ST] | High Eff. - CC [GT+HRSG+ST] | Fast Start - CC [GT+HRSG+ST] | Gas - Recip. [per Engine] |
|---|---|---|---|---|---|---|---|---|---|---|
| Cost Item/ | | | | | | | | | | |
| Typical Hot Start Data | | | | | | | | | | |
| -C&M cost ($/MW cap.) | | | | | | | | | | |
| Median | 71 | 49 | 60 | 30 | 40 | | 42 | 46 | 33 | |
| ~25th_centile | 71 | 36 | 43 | 25 | 18 | | 32 | 35 | 26 | |
| ~75th_centile | 130 | 70 | 77 | 47 | 122 | | 82 | 99 | 80 | |
| Typical Warm Start Data | | | | | | | | | | |
| -C&M cost ($/MW cap.) | | | | | | | | | | |
| Median | 112 | 64 | 78 | 46 | 48 | | 52 | 58 | 47 | |
| ~25th_centile | 94 | 52 | 60 | 34 | 19 | | 29 | 32 | 26 | |
| ~75th_centile | 211 | 82 | 109 | 91 | 131 | | 108 | 139 | 96 | |
| Typical Cold Start Data | | | | | | | | | | |
| -C&M cost ($/MW cap.) | | | | | | | | | | |
| Median | 144 | 114 | 126 | 67 | 57 | 28 | 75 | 84 | 72 | 10 |
| ~25th_centile | 92 | 66 | 85 | 57 | 20 | 11 | 41 | 46 | 39 | 6 |
| ~75th_centile | 333 | 159 | 154 | 104 | 138 | 66 | 117 | 157 | 112 | 15 |
| Typical Non-cycling Related Costs | | | | | | | | | | |
| - Baseload Variable Cost ($/MWH) | | | | | | | | | | |
| Median | 1.79 | 2.40 | 3.76 | 0.29 | 0.56 | 0.45 | 2.10 | 1.80 | 1.72 | 0.00 |
| ~25th_centile | 1.14 | 1.62 | 3.15 | 0.24 | 0.47 | 0.18 | 1.65 | 1.27 | 1.30 | 0.00 |
| ~75th_centile | 2.70 | 3.42 | 4.79 | 1.74 | 1.10 | 0.66 | 4.42 | 4.40 | 4.53 | 0.00 |

## Table 5 — Projected Impact of Cycling on EFOR

| Unit Types | Coal - Small Sub Critical | Coal - Large Sub Critical | Coal - Super Critical | Gas - Steam | Gas - Large Frame CT | Gas - Aero Derivative CT | Typical CC [GT+HRSG+ST] | High Eff. - CC [GT+HRSG+ST] | Fast Start - CC [GT+HRSG+ST] | Gas - Recip. [per Engine] |
|---|---|---|---|---|---|---|---|---|---|---|
| Cost Item/ | | | | | | | | | | |
| Typical Hot Start Data | | | | | | | | | | |
| -EFOR Impact | | | | | | | | | | |
| Median | 0.0194% | 0.0071% | 0.0046% | 0.0062% | 0.0020% | | 0.0028% | 0.0027% | 0.0025% | |
| ~25th_centile | 0.0045% | 0.0035% | 0.0030% | 0.0015% | 0.0007% | | 0.0021% | 0.0021% | 0.0021% | |
| ~75th_centile | 0.0495% | 0.0164% | 0.0130% | 0.0285% | 0.0145% | | 0.0081% | 0.0084% | 0.0070% | |
| Typical Warm Start Data | | | | | | | | | | |
| -EFOR Impact | | | | | | | | | | |
| Median | 0.0308% | 0.0088% | 0.0068% | 0.0114% | 0.0028% | | 0.0043% | 0.0041% | 0.0039% | |
| ~25th_centile | 0.0058% | 0.0059% | 0.0059% | 0.0025% | 0.0007% | | 0.0023% | 0.0023% | 0.0023% | |
| ~75th_centile | 0.0624% | 0.0390% | 0.0390% | 0.0308% | 0.0165% | | 0.0095% | 0.0205% | 0.0186% | |
| Typical Cold Start Data | | | | | | | | | | |
| -EFOR Impact | | | | | | | | | | |
| Median | 0.0318% | 0.0114% | 0.0114% | 0.0171% | 0.0035% | 0.0089% | 0.0058% | 0.0056% | 0.0055% | 0.0020% |
| ~25th_centile | 0.0085% | 0.0047% | 0.0060% | 0.0041% | 0.0007% | 0.0036% | 0.0033% | 0.0033% | 0.0033% | 0.0011% |
| ~75th_centile | 0.0652% | 0.0300% | 0.0202% | 0.0467% | 0.0118% | 0.0199% | 0.0091% | 0.0215% | 0.0195% | 0.0031% |

# 3 | Conclusions

Some of the observations from the figures and tables are as follows:

- There is a large spread of cycling costs as well as reliability impacts.
- On a per megawatt basis, small coal units have the highest cost, while the gas reciprocating engines are the lowest cost. This trend is reflected in terms of the reliability impacts also. Small coal units have the most significant impact while reciprocating engines are designed for flexible operation and hence have the least effect.
- Examining the results published by Intertek AIM in 2012, we estimate the cost of hot and warm starts on conventional steam units (subcritical coal and gas steam units), will be slightly lower in 2030 (results are in 2020$). The drivers for the lower start cost are both the expected increase in the different start types, as well as lower overall spend.
- Small subcritical coal will be subject to increased cycling (lower capacity factors), along with reduced total O&M spend similar to recent trends. This increased cycling, as well as aging, results in significant impact on reliability.
- Larger coal units have similar lower future O&M spend but will likely operate in load following mode with extended shutdowns (cold starts). Therefore, cold start costs increase, while other start costs remain similar or lower to results published in 2012.
- Supercritical coal power plants are operated at baseload and do not cycle on/off much. As these units age and are forced to operate in more flexible mode, the cost of cycling is likely to increase. This will result in slightly lower “baseload VOM” costs compared to historical results. These units cannot easily be brought online under these circumstances and such factors are not fully captured in this dataset. Note that there is a relatively small sample of supercritical coal units in WECC.
- Median cold start cost for each of the generation types is about 1 to 3 times the hot start capital and maintenance cost. For the lower bound 75th percentile, this ratio of cold start cost versus hot start cost is only slightly higher.
- Aeroderivative gas turbines and reciprocating gas engines are designed for flexible operation, and therefore have lower costs. These units also do not get heavily impacted in terms of reliability. In the case of gas turbines, the typical maintenance cycle of the units essentially renews the wear and tear damage. Note that fast starts are deviations to standard start sequence, which may result in increased cycling costs.
- There are some important economies of scale for large steam units that lower their per cycle costs. So, the highest costs per capacity, as shown here, occur in some less efficient or older smaller units, especially for cold starts.
- There is an inherent “tradeoff” relation between higher capital and maintenance expenditure and corresponding lower EFOR.
- Aging effects on conventional combined-cycle units is significant (in 2030). Older units act more like the present coal fleet, while the newer combined-cycle units tend to operate baseload or load following.

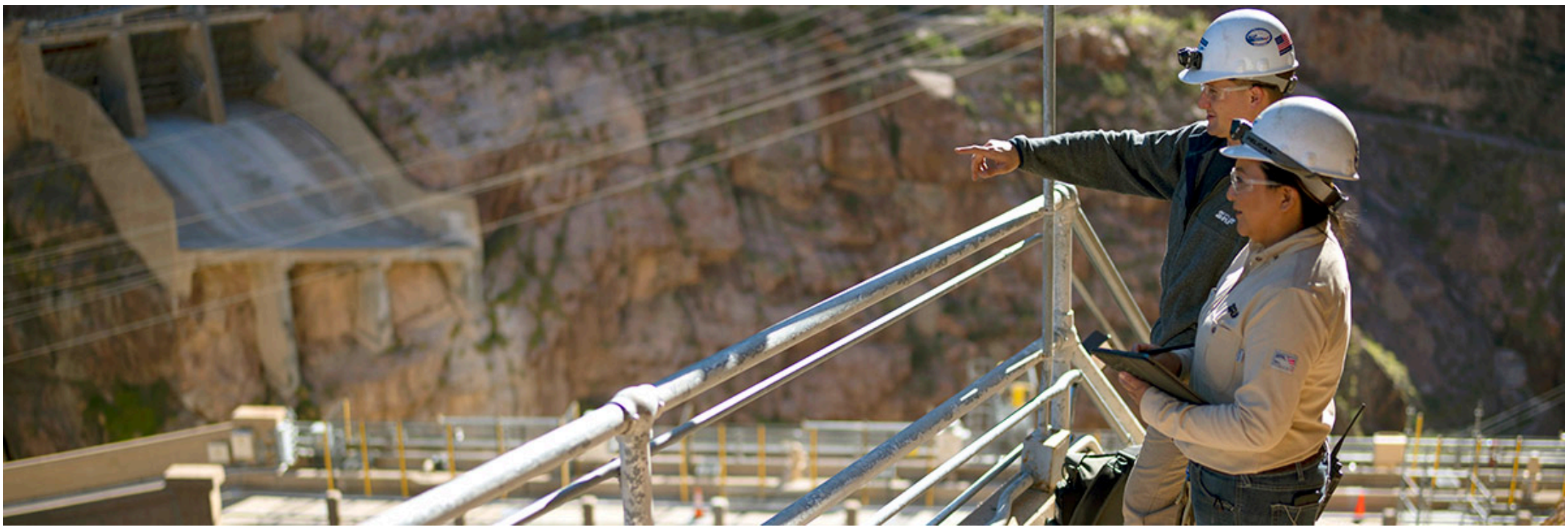
- Conventional (older) combined-cycle units were designed for baseload operation and when operated in cycling mode can have higher cycling costs. Similarly, the more efficient, higher temperature gas turbine-based combined-cycle units are also not designed for frequent start/stops. Hence, the cost per cycle of the high efficiency gas combined-cycle units is modestly higher than older combined-cycle units. The fast start combined-cycle units, as expected, are much more economical to operate in on/off mode.
- Reciprocating engines almost always operate as flexible units. The baseload VOM cost for these units is negligible as all the costs are cycling related. These units also do not see much effects on reliability from increased on/off cycles. At low load operation, typically engines on a site may be turned off.
- The coal-fired small and large units were the expensive load following units. As an example, the mill cycle from full load to low load adds significant costs. Emissions control equipment is also affected when units are operated at minimum load for extended hours.
- The combined-cycle units tend to have slightly lower but significant load following costs. This is true because the steam cycle components (i.e., the HRSG, ST, and balance of plant equipment) are impacted by changing operating transients at lower loads. The HRSG is the significant contributor to the cost, though some STs in the industry have been adversely affected by extended low load operation.
- Modest increases in ramp rates during load following results in almost no increase in damage or costs. Doubling accepted ramp rates (subject to design limit or original equipment manufacturer recommendation) is possible on the steam units, though such operation will increase costs. Yet, there might be market mechanisms that allow units to take advantage of the faster ramp rates.
- Aggregating cycling costs at the system level results in ignoring the “flash flood” situation of heavy cycling on individual units on the grid. Transmission expansion studies should include power plant cycling as an input.

BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

| | |
|---|---|
| Federal Power Act Section 202(c) | ) |
| Emergency Order: Tri-State | ) |
| Generation and Transmission | ) |
| Association, Platte River Power | ) |
| Authority, Salt River Project, | ) |
| PacifiCorp, and Xcel Energy | ) |

Exhibit to
Motion to Intervene and Request for Rehearing and Stay of
Public Interest Organizations

Exhibit 2-60:
SRP Power Generation Sources



# SRP power generation sources

SRP is strengthening and preparing the grid for a future that's powered by renewable energy while maintaining the reliability we need to keep your family safe.

**On this page:**

Explore SRP power sources

Sustainability at SRP

Technology and innovation

**On related pages:**

Santan Generating Station reports & action plans

Coolidge Generating Station reports & action plans

Feedback

## Explore SRP power sources

SRP operates and participates in a number of major power plants and generating facilities in Arizona and around the Southwest. As we add more renewable energy sources to our energy mix, we're strategically using traditional energy sources like natural gas and coal to reliably strengthen our power grid, especially during the hot summer months when energy needs are at their highest.

Explore our diverse energy mix by source or location on the map below.

Filter by Technology

Coronado

Apache County, AZ

Operating Year: 1979

Conventional Steam Coal

Craig (CO)

Moffat County, CO

Operating Year: 1980

Conventional Steam Coal

Davis

Mohave County, AZ

Operating Year: 1951

Conventional Hydropower

Desert Basin

Casa Grande, AZ

Operating Year: 2001

Natural Gas

Dorman Battery

Chandler, AZ

Operating Year: 2018

Battery

Dry Lake Wind

Navajo County, AZ

Operating Year: 2009

Onshore Wind Turbine

East Line Solar

Coolidge, AZ

Operating Year: 2020

Solar Photovoltaic



**Craig (CO)**: Conventional Steam Coal

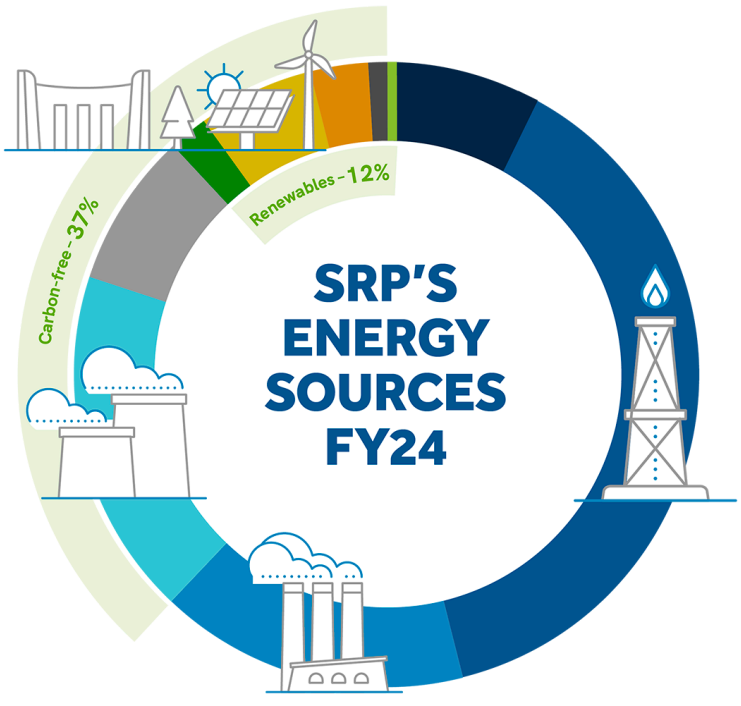
Operated by Tri-State Generation and Transmission, SRP owns a share of this three-unit station (29% of Unit 1 and 29% of Unit 2) located in northwestern Colorado. SRP is committed to reducing our carbon emissions, and we are starting to decommission certain coal-fired plants. The plan includes decommissioning Craig Unit 1 in 2025 and Unit 2 in 2028.

Esri Community Maps Contributors, © OpenStreetMap, Microsoft, Esri, TomTom, Garmin, SafeGraph,… Powered by Esri

Feedback

## Sustainability at SRP

As part of our commitment to achieve net zero carbon by 2050, we are expanding our mix of clean, renewable energy sources.




**We are committed to net-zero carbon emissions by 2050.**

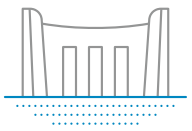
**MARKET – 8%**
**NATURAL GAS – 38%**
**COAL – 16%**
**NUCLEAR – 18%**
**CUSTOMER PROGRAMS – 8%**
**HYDRO – 2%**
**SOLAR – 5%**
**GEOTHERMAL – 3%**
**WIND – 1%**
**BIOMASS – <1%**

*The pie chart shows how the power needs of SRP's retail customers were met during fiscal year 2024 (May 1, 2023–April 30, 2024). This chart represents generation output from all generating facilities operational in FY24. Generation data is pending third-party verification by The Climate Registry.*

*SRP is committed to cutting carbon emissions intensity by 65% by 2035 and reaching net zero by 2050. Learn more about sustainability at SRP.*

## Renewables

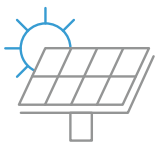
At SRP, we're steadily expanding our energy portfolio to include more power from carbon-free sources.



### Hydropower

SRP manages eight dams on the Salt River and Verde River watersheds that provide more than 230 megawatts (MW) of hydropower.

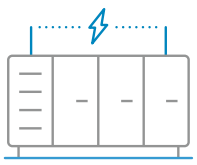
Learn more



### Solar

SRP is harnessing the power of America's sunniest city to support a variety of solar solutions for homes and businesses.

Learn more



### Battery storage

SRP uses large-scale battery storage projects to store renewable energy for when it is most needed to support grid reliability.

Feedback

Learn more



### Other renewables

SRP is investing in additional carbon-free resources like wind, geothermal and biomass.

Learn more

*SRP generation resources comply with local, state and federal air quality regulations which are protective of human health and the environment. Learn more about our environmental policies and programs.*

## Technology and innovation

We're continually working to provide reliable, affordable and sustainable power today and for Arizona's future. Check out the stories below to learn how we're innovating today to ensure Arizona continues thriving tomorrow.



### Powering the grid with solar

Learn more

Feedback



## Powering carbon neutrality with new energy storage technology

Learn more

BACK TO TOP

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[Future plan for energy | SRP]

Ensuring that the Valley's energy future remains reliable requires energy experts and communities working together. Learn about SRP's energy plan for the future.



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Protecting and preserving natural and cultural resources is at the core of SRP's mission. Learn more about SRP's environmental programs here.



[Sustainability at SRP]

The future of our water and power resources depends on the actions we take today. See how we're working toward a sustainable future.



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| | |
|---|---|
| Federal Power Act Section 202(c) | ) |
| Emergency Order: Tri-State | ) |
| Generation and Transmission | ) |
| Association, Platte River Power | ) |
| Authority, Salt River Project, | ) |
| PacifiCorp, and Xcel Energy | ) |

Exhibit to
Motion to Intervene and Request for Rehearing and Stay of
Public Interest Organizations

# Exhibit 2-61:
# 2023 ERP Phase II Modeling Assumptions

Colorado PUC E-Filings System

# Modeling Assumptions

The following table and discussion identify the modeling assumptions to be used in Phase I of Tri-State's 2023 ERP.

*Table 1: Modeling Assumptions*

| Category | Assumption | Description of Modeling Input |
|---|---|---|
| **Financial** | Electric and Gas Forward Curves, and Transport Cost | • Horizon[1] 2023 Spring Forecasts for electric and gas forward curves<br>• Transport adders based on interstate gas provider rates |
| | Coal Forward Curve | March 2023 forecast in real and nominal dollars |
| | Capital Expenditures and Fixed O&M | Tri-State 2023 O&M Budget and 10-Year Capital Plan |
| | Variable O&M | 2023 O&M Budget of thermal resource VOMs |
| | Annual Inflation Forecast | Annual inflation projections as of February 2023 |
| | Depreciation Costs and Schedules | 2023 Depreciation Study will inform the rate that existing assets are depreciated in the financial modeling |
| | Renewable and Storage Generic Resource Prices – PPAs and Build Transfers | Updated based on 2020 ERP Phase II bid responses, IRA impacts, latest PTC/ITC, and $1/MWh Wyoming Wind Tax |
| | Gas Generic Resource Build Prices | B&V reviewed and refreshed generic gas pricing |
| | Innovative Technology Pricing | Newly added resource types and modeling assumptions (e.g., Small Modular Reactors, Hydrogen, Molten Salt Long-Term Storage, Iron Air Storage, Geothermal, etc.) |
| | Resource Integration Adder (Ancillary Service Costs) | Generic resources (as applicable) as follows: WCO, WY-WNE, and ECO updated with WACM; and NM updated with PNM |
| | Discount Rate / Weighted Average Cost of Capital (WACC) | Updated to 4.12% |
| | LRS 2 & 3 Retirement Cost Profile | Reflects continuation of fixed and capex costs through useful life |
| | Springerville Unit 3 (SPV 3) Retirement Cost Profile | Financing and equity partner penalties applicable if unit retired early |
| | Craig Station Decommissioning Cost | Reflects third-party cost estimate, and Tri-State's share of the cost |
| | Book Life for Generic Li-Ion Batteries, Renewables, and Gas | Use of book life assumptions for each generic resource and useful life for each existing resource |
| | Third Party Transmission | • Reflects network and firm point to point transmission available between planning regions |

[1] Horizons Energy is a data and analytics consulting company providing market price forecasts for the energy industry. See: https://www.horizons-energy.com/market-price-forecasting/.

| | | |
|---|---|---|
| | | • Added ability to procure additional transmission between planning regions as available at a cost. |
| **Operational** | CRSP Hydro Forecast | Forecasted capacity from CRSP hydro contract reflects continued reduction through the planning period due to drought. |
| | Load Forecast | Forecast as of Summer 2022 with United Power and Northwest Rural Public Power District exiting May 1, 2024 and Mountain Parks exiting February 1, 2025 |
| | | Partial Requirements Contracts for May 2021 and May 2022 Open Seasons (excluding Mountain Parks) included as applicable load reductions beginning January 2026 |
| | Beneficial Electrification | Achievable-Moderate level from 2023 BE Potential Study[2] |
| | Distributed Generation Forecast | Forecast of Member DG as of March 2023 with appropriate Member exits (United Power and Mountain Parks) |
| | Constraints | Updated constraints on new resource builds and transmission interconnection |
| | Level I & II Reliability Metrics | Scenarios were modeled to meet minimum Level I and II reliability requirements |
| | Thermal Build Constraint | No thermal builds allowed before 2028 |
| | Gas Retirement Constraint | No gas resources allowed to retire |
| | Coal Unit Uptime | Uptime minimum 12 hours |
| | Coal Unit Downtime | Downtime minimum 8 hours |
| | Craig 3 Modeling | Craig 3 is modeled in ECON mode |
| | Craig Unit Retirements | • Craig Units 1 and 2 retirements are modeled to occur on the announced dates.<br>• Craig Unit 3 is modeled to retire between 2028-2029.[3] |
| | Tri-State Exit MBPP[4] | Allowed in modeling beginning January 1, 2027 |
| | SPV 3 Retirement | Allowed in modeling beginning January 1, 2037 |
| | SPV 3 Max Capacity | SPV 3 rerated to 419 MW per 2022 testing |
| | Effective Load Carrying Capability (ELCC) | Based on third-party study |
| | Scheduled Outages | Planned outage schedules updated for all thermal units |
| | Forced Outage Factors | Applied unit-specific rates based on 5 years of historical data from GADs. Updated forced outage method in dispatch runs to have random outage days instead of a derate. |
| | Modeling of Market Sales and Purchases Depths | • Market sales and purchases hourly depth updated.<br>• Values are reflective of: |

[2] Attachment G-3 of the ERP Report (LKT-1)
[3] Also see Attachment B-3 of the ERP Report (LKT-1) for unique scenario assumptions.
[4] Tri-State has no current plans to exit the Missouri Basin Power Project ("MBPP") – see written information regarding this modeling assumption below.

| | | |
|---|---|---|
| | | ○ Member exits<br>○ Moving WACM load (WY/WNE, WCO and a portion of ECO) to SPP RTO in April 2026<br>○ Remainder of ECO load and all NM load to RTO by 2030. |
| | Modeling of Term Sales | Known and anticipated term sales opportunities are reflected in modeling |
| | Modeling of Proxy Sales | Anticipated capacity and energy sales opportunities are reflected in modeling |
| | Generic Resource Availability | The model will be able to select generic resources starting in as soon as 2026, depending on lead time of each technology |
| | PPA and Contract Information | Updated latest known COD and reflect any updated terms |
| | SRP Contract | Model based on market optimization |
| | System Loss Factor | NM region losses are financial; updated ECO, WCO and WY/NE to 3.5% |
| **Demand-Side Management** | Demand Response | DR Target (4% of load) modeled for ECO and WCO; Tri-State DR Program Levels selectable for NM and WY |
| | Energy Efficiency (EE) | EE Targets modeled for ECO and WCO; Achievable-Low NM and Low WY allowed for model to select and updated per Mesa Point 2023 DSM Potential Study[5] |
| **Environmental** | Emissions and Water Use Rates | Updated generator emission and water use rates per TS Environmental and eGrid 2021 rates, as applicable. Thermal resource rates were provided by B&V, while rates for innovative technologies were sourced from public resources. |
| | Emissions Reduction Targets | 26% in 2025<br>36% in 2026<br>46% in 2027<br>80% in 2030 |
| | APCD Workbook Inputs and Resource, Market & Contract Emissions Rates | *2005 Emissions Baseline:* Updated to reflect Partial Requirements Contracts and Member Exits |
| | | *Market & Contract Emissions Rates:*[6] Generator Resource emission rates updated per TS Environmental. Basin Eastern Interconnection contract updated to 2021 eGRID MROW rates; Basin Western Interconnection contract proxy emission rate is updated to LRS rate for 2025 and 2021 eGRID rate for 2026 to 2029. Market purchase and |

[5] May 2023 "Addendum to 2020 Demand-Side Management and Energy Efficiency Potential Study."
[6] Settlement Agreement section 3.11.3. "…Tri-State will use published system, region or market rates as applicable and consistent with APCD regulations and guidance for unspecified source market and contract purchases…" and section 3.11.4. "…Tri-State will convene a meeting before the next ERP to discuss the emissions rate for unspecified energy purchases…" That meeting was held on August 16, 2022.

| | | |
|---|---|---|
| | | sales updated to 2021 eGRID RMPA and AZNM rates as applicable. |
| | Social Cost of Carbon | As of February 2021 IWG[7] @ 2.5% discount rate |
| | Social Cost of Methane | As of February 2021 IWG @ 2.5% discount rate |

***Financial***

### Electric and Gas Forward Curves, and Transport Costs

Tri-State has updated the electric and gas forward curves using Horizons Energy's Spring 2023 Advisory Reference Case results. The Advisory Service provides fundamental analysis of electricity markets. Horizons Energy produces the EnCompass National Database for developing fundamental prices of the electricity markets including fuel and energy throughout North America related to integrated resource planning. Horizons Energy used Henry Hub gas forward prices from Natural Gas Intelligence through December 2023 and then trended forward through 2050. Cheyenne Hub forecasted basis is used for CIG and Waha forecasted basis is used for Waha fuel curves. Horizons Energy electric forward curves are provided for the four WECC areas of Eastern and Western Colorado, New Mexico, and Wyoming. Tri-State forward price curve blends all four areas equally for an average hourly market price through 2050. Monthly forward price curves are modeled in real 2023 dollars.

Figure 1 represents the electric forward curve data in real (2023) dollars for the resource planning period (RPP):



Figure 2 represents the gas forward curve in real (2023) dollars.

[7] https://www.whitehouse.gov/wp-content/uploads/2021/02/TechnicalSupportDocument_SocialCostofCarbonMethaneNitrousOxide.pdf

[redacted]

Table 1 summarizes the additional transport costs and forward curves associated with each gas generating unit:

*Table 1: Transportation Costs & Fuel Forward Curve for Gas Resources*

| Existing Gas Plant | [redacted] | Forward Curve |
|---|---|---|
| **Limon** | [redacted] | CIG |
| **Knutson** | [redacted] | CIG |
| **Pyramid** | [redacted] | Waha |
| **JM Shafer** | [redacted] | CIG |
| **Generic Gas Resources – CO & WY** | [redacted] | CIG |
| **Generic Gas Resources – NM** | [redacted] | Waha |

## Coal Forward Curve

Tri-State's forward coal prices change at least annually. The coal price forecast, including rail delivery fees (or "freight"), are used in EnCompass and in the final PVRR analysis in UIPlanner. Tri-State updated the Craig coal forward curve in March 2023. [redacted]

[redacted]

[redacted]



[redacted]



## Capital Expenditures and Fixed O&M

Tri-State forecasts capital expenditures based on actual planned or expected projects. Tri-State updated its capital expenditure forecast for use in the modeling.

[redacted][9]

[redacted]

Tri-State also reviews historical data for O&M costs and incorporates known changes impacting future O&M costs to produce an annual forecast of O&M costs. Tri-State utilized its O&M forecast to derive a new fixed O&M forecast for use in the modeling.

[redacted]

[redacted]

## Variable O&M

The variable O&M (VOM) reflects the latest average VOM calculated by Tri-State Generation Engineering for the units. Use of the most recent average VOM results in [redacted]

[9] Axial Basin and Dolores Canyon solar resources are not yet operational; therefore, no capital expenditures have been forecasted. Initial capital construction cost is reflected in the financial analysis.

[redacted] Other units' average VOM costs remained relatively consistent with values used in previous modeling.

[redacted]

## Annual Inflation Forecast

Tri-State's financial planning and analysis team applies an assumed rate of inflation to adequately budget fixed costs and modeled capital and O&M expenditures used in ERP modeling throughout the resource planning period. The escalation rate is 2.5% in 2024, 2.2.% in 2025, 2.30% in 2026 and 2027, and 2.15% thereafter.

## Depreciation Costs and Schedules

Depreciation costs and schedules for existing resources were modeled based on Tri-State's 2023 Generation Plant Depreciation Study completed in May 2023. Also see Attachment C-3 of the ERP Report (Attachment LKT-1). Generic resource modeling assumptions, including book life and operating life, can be found in Attachment C-2.

## Renewable and Storage Generic Resource Prices – PPAs and Build Transfers

Tri-State's consultant, CDG, updated the forward price curves for generic renewable, and hybrid resource Power Purchase Agreements (PPAs) as well as renewable build-transfer and standalone storage build costs reflect updated capital and operating expense forecasts, Inflation Reduction Act (IRA) tax credit additions and extensions (production tax credits (PTC) and investment tax credits (ITC)), 2020 ERP Phase II pricing, and, for generic wind in Wyoming, the Wyoming $1/MWh "Wind Tax" is included.

## Gas Generic Resource Build Prices

In 2023, Black & Veatch (B&V) reviewed and refreshed generic gas pricing assumptions for the ERP. The assumptions can be found in Attachment C-2: Generic Resources Summary.

## Innovative Technology Pricing

Per the 2020 ERP Phase I Settlement Agreement,[10] Tri-State added new generic resource types (e.g., Small Modular Reactors, Hydrogen, Molten Salt Long-Term Storage, Iron Air Storage, Geothermal, etc.) with associated pricing and technology assumptions, as identified in Attachment C-2: Generic Resources Summary.

## Resource Integration Adder (Ancillary Service Costs)

Integration Adders are modeled to reflect the ancillary service cost for generic resources in the Balancing Authority Area (BAA) operating in each Tri-State planning region. The adders were updated to reflect 2023 pricing and were applied in the modeling are as follows:

PNM (NM):

- No extra intermittent resource specific charges

WACM (WCO, WYO-WNYE, and ECO):

- Wind: Schedule 3 Regulation $0.4293/kW month
- Solar: Schedule 3 Regulation $0.8427/kW month

## Discount Rate

Tri-State's weighted average cost of capital (WACC), or discount rate, as of February 2023 was 4.12%. For comparison, Tri-State's WACC was 4.18% in 2020 ERP Phase II and 4.15% in 2020 ERP Phase I.

## LRS 2 & 3 Retirement Cost Profile

Tri-State's portion of the fixed O&M and capital expenditures for Laramie River Station (LRS) Units 2 and 3 are reflected in the financial analysis for each scenario as a sunk cost, continuing through each unit's useful life. Given that these costs are a contractual obligation, they are not an avoidable cost in the expansion plan modeling.

## Springerville Unit 3 Retirement Cost Profile

Springerville Unit 3 (SPV 3) retirement cost profile reflects the latest estimated calculation of the following [redacted]

- [redacted]
- [redacted]
- [redacted]

The SPV 3 retirement cost profile still does not reflect potential penalties or costs associated with early contract termination, or facilities and operational costs for shared facilities under joint ownership, which could occur under an early retirement scenario, but continue to be unknown at this time.

[10] Section 3.11.15 of Attachment A of the Unopposed Comprehensive Settlement Agreement, filed January 18, 2022 in Proceeding No. 20A-0528E.

### Craig Station Decommissioning Cost

The cost for decommissioning Craig Station was updated in the financial modeling, replacing the previous internal estimate with an estimate that reflects a third-party quote. The decommissioning cost was also updated to reflect Tri-State's share of the cost.

### Book Life for Generic Li-Ion Batteries, Renewables and Gas

Generic resources' book life assumptions are identified in Attachment C-2. Useful life of existing resources is identified in Attachment C-3.

### Third Party Transmission

All available third-party transmission between planning regions, whether network or purchased long term firm point to point transmission, is included in the model and associated sunk costs are included in the financial model. Also included in the dispatch model is the option to purchase:

- up to 133 MW of hourly transmission at PSCO's Open Access Transmission Tariff (OATT) rate as needed for additional transfers from ECO to NM;
- up to 76 MW of third-party transmission at CRSP's OATT rate from ECO to WCO at an incremental cost; and
- up to 100 MW of third-party transmission at PNM's OATT rate from NM to ECO at an incremental cost.

## *Operational*

### CRSP Hydro Forecast

Energy and capacity profiles for Colorado River Storage Project (CRSP) contracts through the RPP are at normal levels, for the following regions: CRSP ECO, CRSP NM, CRSP WCO. This assumption is in light of the U.S. Bureau of Reclamation's May 2023 projection[11] for the Colorado River system of a 0% probability of minimum power pool through 2027 along with recent improvements in near term hydro allotments.

### Load Forecast

The load assumptions used in the modeling are based on Tri-State's latest finalized long-term load forecast produced in June 2022. The methodology used for load forecasting is outlined in Attachment F of the ERP Report (LKT-1). Adjustments were made to the forecast to reflect Member exits,[12] Partial Requirements contract load reductions, Colorado energy efficiency, system-wide beneficial electrification for the Tri-State system, and member distributed generation.

Member exits assumed include the following:

- United Power exiting May 1, 2024;
- Northwest Rural Public Power District (NRPPD) exiting May 1, 2024; and

[11] https://www.usbr.gov/lc/region/g4000/riverops/crss-5year-projections.html

[12] Paragraph 63 of Decision No. C23-0437, issued in Proceeding No. 20A-0528E, directed Tri-State to "…submit a load forecast that is indicative of anticipated member departures at the time of filing…"

- Mountain Parks exiting February 1, 2025.

Tri-State is no longer planning its system or acquiring resources to serve the load and reliability needs of these three Members, therefore they are not included in the resource plan.

Separate from the gross load forecast, an offset for 280 MW of Partial Requirements[13] load reduction is included in the model. The quantity of Partial Requirements Member MAX selections known at the time of the start of modeling is 163 MW beginning in 2026 and the quantity for MARS selections is 117 MW beginning in 2026. Based on this, the 163 MW MAX selections reduce the system capacity that Tri-State is responsible for by 163 MW, but the 117 MW MARS selection is a capacity reduction at a prorated amount equivalent to the type of intermittent resource selected (modeled as utility-scale solar). Partial Requirements elections reflect May 2021 and May 2022 Open Seasons, excluding Mountain Parks' election.

System-wide beneficial electrification, discussed below, is added to the load forecast, and Colorado energy efficiency targets—which were modeled as a base assumption in every scenario rather than as a selection by the dispatch model—are subtracted from the gross load forecast in modeling every scenario. Member-owned renewable or distributed generation projects are a deduction to gross load in the modeling process.

## Beneficial Electrification

Beneficial Electrification (BE) is included in ERP modeling as additional load in the load forecast. An Achievable-Moderate level BE is modeled for all planning regions in all 2023 ERP Phase I scenarios in alignment with the 2020 ERP Phase I Settlement Agreement.[14] The Achievable-Moderate level of BE load is determined by the BE Potential Study (Attachment G-3 of the ERP Report (LKT-1). "Achievable" potential takes into account barriers that hinder consumer adoption of measures and the capability to ramp up BE program activity over time. The BE Potential Study incorporated the following BE technologies and program opportunities: electric building heating measures, electric vehicles and non-road electric vehicles, cooking measures, and electric equipment such as lawn and garden equipment.

The Achievable-Moderate level of potential assumes BE measures are incented at 50% of the incremental cost, resulting in ~668 GWh of cumulative growth on the Tri-State system through 2040 (roughly 4.4% addition to 2040 base gross load). In the ERP financial analysis, the cost of attaining an Achievable-Moderate level of BE is reflective of Tri-State BE staff forecasted expenditures for incentives and program delivery.

## Distributed Generation Forecast

Distributed generation (DG) forecast consists of energy and demand forecasts on a project level for Member self-supply options, including Board Policy 115 – renewable distributed generation on Member Systems, Board Policy 119- Community Solar, and Partial Requirements MARS options. Projects are forecasted based on technology type and location with the use of historical load shapes where available.

[13] Partial Requirements Members can select MAX (Firm capacity) or MARS (intermittent resource) options.
[14] Section 3.11.11.

### Constraints

See Attachments B-1 and B-2 of the ERP Report (LKT-1).

### Level I & II Reliability Metrics

All 2023 ERP scenarios were modeled to achieve the minimum Level I and II Reliability Metrics identified in the ERP Report (LKT-1).

### Thermal Build Constraint

No new thermal builds allowed until 2028 due to infeasibility of engineering, procurement, construction, and permitting completion prior to 2028.

### Gas Retirement Constraint

Gas and oil units, including those with dual-fuel capability available for contingency operations are not allowed to retire in the modeling given that they are necessary for maintaining reliability. These units operate during extreme weather events, support market price arbitrage to reduce costs, support reliability during coal unit outages, and can offer surplus interconnection benefits for co-located renewable resources.

### Coal Unit Uptime

Minimum run-time for all coal units was set to 12 hours in the modeling, reflective of a May 2020 report[15] by the Western Electricity Coordinating Council (WECC).

### Coal Unit Downtime

Minimum down-time for all coal units was set to 8 hours in the modeling, reflective of a May 2020 report[16] by the WECC.

### Craig 3 Modeling

Per the 2020 ERP Phase I Settlement Agreement,[17] Tri-State modeled Craig 3 in the ECON designation, allowing the model to economically commit and dispatch the unit subject to the minimum up and down times.

### Craig Unit Retirements

Craig Units 1 and 2 retirements are modeled to occur on the announced dates; and Craig Unit 3 is modeled to allow the unit's retirement between January 1, 2028 and December 31, 2029, except where otherwise modeled per unique scenario assumptions (see Attachment B-3: Unique Scenario Assumptions of the ERP Report (LKT-1)). Craig Unit 3 is not allowed to retire prior to January 1, 2028 in the modeling to ensure sufficient lead-time for the community transition between completion of the 2023 ERP and the earliest potential retirement date and to allow sufficient time for replacement resources to be secured. Craig Unit

[15] *Update of Reliability and Cost Impacts of Flexible Generation on Fossil-fueled Generators for Western Electricity Coordinating Council*, May 12, 2020; Table 2, page 21 (720 minutes Minimum Up Time for coal units). Available: 1r10726 WECC Update of Reliability and Cost Impacts of Flexible Generation on Fossil.pdf.
[16] *Update of Reliability and Cost Impacts of Flexible Generation on Fossil-fueled Generators for Western Electricity Coordinating Council*, May 12, 2020; Table 2, page 21 (480 minutes Minimum Down Time for coal units). Available: 1r10726 WECC Update of Reliability and Cost Impacts of Flexible Generation on Fossil.pdf.
[17] Section 3.6.6.

3 is not allowed to retire later than December 31, 2029 given that date is the publicly announced retirement date for the unit as identified in Colorado Regulation No. 23 Regional Haze Limits.

### Tri-State Exit MBPP

Tri-State has no current plans to exit the Missouri Basin Power Project ("MBPP"). Tri-State is an MBPP participant and receives a portion of Laramie River Station (LRS) generation and transmission through its share of the MBPP contract. Tri-State is only a partial owner of LRS, therefore any "LRS early retirement" modeling simulates Tri-State exit of the MBPP Agreement, not retirement of the unit. This assumption is applied to be informative to the resource plan modeling.

### SPV 3 Retirement

SPV 3 is allowed to retire beginning January 1, 2037, upon the conclusion of the 100 MW third-party supply contract (Fall 2036), except where otherwise modeled per unique scenario assumptions (see Attachment B-3 of the ERP Report (LKT-1)).

### SPV 3 Max Capacity

In July 2022, a capacity test was conducted affirming the previous maximum capacity rating for SPV 3 of 419 MW.

### Effective Load Carrying Capability

ELCCs were updated for wind, solar, storage, coal, and gas resources for the 2023 ERP based on the third-party study completed in August 2023. The ELCC methodology and study results are provided in Attachment G-1 of the ERP Report (LKT-1). For capacity expansion modeling, firm capacity of each unit reflects the Equivalent Forced Outage Rate (eFOR) by unit identified in *Table 18. TSGT UCAP Capacity* of Attachment G-1 of the ERP Report (LKT-1).

### Scheduled Outages

The following identifies the scheduled outages modeled for coal units during the RAP.

*Table 4: Scheduled Coal Unit Outages During the RAP*

[redacted]

## Forced Outage Factors

Dispatch plan modeling reflects the average FOFs by unit,[18] as shown in Table 5.

*Table 5: Thermal Unit Forced Outage Factors (FOFs)*

| Unit | 5-yr Average FOF (%) |
|---|---|
| **Craig 1** | 4.00 |
| **Craig 2** | 2.05 |
| **Craig 3** | 13.89 |
| **LRS 2** | 6.49 |
| **LRS 3** | 7.18 |
| **SPV3** | 5.78 |
| **Burlington 1** | 0.99 |
| **Burlington 2** | 0.53 |
| **Knutson 1** | 1.98 |
| **Knutson 2** | 0.72 |
| **Limon 1** | 0.67 |
| **Limon 2** | 0.33 |
| **Pyramid 1** | 0.19 |
| **Pyramid 2** | 1.24 |
| **Pyramid 3** | 0.44 |
| **Pyramid 4** | 0.95 |
| **JM Shafer** | 4.71 |

These FOF factors were developed using five years of historical FOFs data from 2018-2022, shown in Table 6.

*Table 6: Historical Thermal Unit FOFs*

| Unit | 2018 | 2019 | 2020 | 2021 | 2022 |
|---|---|---|---|---|---|
| **Craig 1** | 5.53 | 1.21 | 3.35 | 8.18 | 1.75 |
| **Craig 2** | 0.27 | 2.18 | 0.99 | 2.17 | 4.65 |
| **Craig 3** | 45.24 | 3.39 | 3.67 | 4.36 | 12.78 |
| **LRS 2** | 6.33 | 2.20 | 7.82 | 12.71 | 3.39 |
| **LRS 3** | 0.01 | 0.51 | 10.34 | 23.47 | 1.56 |
| **SPV3** | 7.77 | 9.09 | 1.41 | 7.8 | 2.82 |
| **Burlington 1** | 2.46 | 0.70 | 0.43 | 1.34 | 0 |
| **Burlington 2** | 0.67 | 0.32 | 0.35 | 0.87 | 0.45 |
| **Knutson 1** | 0.33 | 0.89 | 0.22 | 0.03 | 8.45 |
| **Knutson 2** | 0.21 | 0.66 | 1.55 | 0.4 | 0.77 |
| **Limon 1** | 1.71 | 0.29 | 0.06 | 0.01 | 1.29 |

[18] The input field in EnCompass is FOR.

| Unit | 2018 | 2019 | 2020 | 2021 | 2022 |
|---|---|---|---|---|---|
| **Limon 2** | 0.45 | 0.57 | 0.12 | 0.45 | 0.07 |
| **Pyramid 1** | 0.27 | 0.35 | 0.02 | 0.02 | 0.31 |
| **Pyramid 2** | 2.76 | 0.07 | 0.39 | 0 | 2.97 |
| **Pyramid 3** | 0.26 | 0.97 | 0.91 | 0.08 | 0 |
| **Pyramid 4** | 0.26 | 2.41 | 0.18 | 1.88 | 0 |
| **JM Shafer** | 5.04 | 13.13 | 1.46 | 2.12 | 1.8 |

EnCompass randomly selects for each day how many individual units will be forced out due to operational failure. This random selection is based on the FOR and Random Outage Seed inputs. The model uses the FOR to determine the number of full forced outage days per year and will randomly select the dates in each year.

## Modeling of Market Sales and Purchase Depths

All market purchases and sales are transacted at a regional level trading hub within the model. Market depths in 2024 are reflective of Member exits, and access to existing Western Energy Imbalance Market (WEIM) and Western Energy Imbalance Service (WEIS) markets. Market depths beginning in 2026 are reflective of the WACM BA moving to SPP RTO. Additional market depth in ECO is added in 2030 reflective of an assumption that PSCo will be in an RTO by 2030. Market depths in New Mexico are reflective of assumptions that PNM joins an RTO by 2030. The tables below show the market depths as modeled.[19]

*Table 7: Market Sales Characteristics*

| Market | 2024-March 2026 | April 2026-2029 | 2030- |
|---|---|---|---|
| | ATC (MW) | ATC (MW) | ATC(MW) |
| ECO | 200 | 250 | 300 |
| WCO | 100 | 200 | 200 |
| NM | 75 | 75 | 150 |
| WYO-WNE | 100 | 200 | 200 |

*Table 8: Market Purchase Characteristics*

| Market | 2024-March 2026 | April 2026-2029 | 2030- |
|---|---|---|---|
| | ATC (MW) | ATC (MW) | ATC (MW) |
| ECO | 150 | 200 | 200 |
| WCO | 100 | 200 | 200 |
| NM | 100 | 100 | 200 |
| WYO-WNE | 75 | 200 | 200 |

Tri-State currently meets its contingency reserve requirements through its membership in the Southwest Reserve Sharing and two sub-entity Reserve Sharing Group agreements. Modeling includes contingency

[19] Market sales were reviewed by a third-party consultant in May 2023.

reserve requirements for these existing reserve sharing groups. Potential regulation and contingency reserve sales opportunities within the SPP RTO are not reflected in the Phase I modeling.[20]

## Modeling of Short & Long-Term Sales

Modeling reflects existing term sales as follows:

- **City of Farmington Sale** (Modeled as a Term Sale)**:** 25 MW per hour maximum on-peak capacity; 15 MW per hour maximum off-peak capacity ~181 GWh/year in energy sales. Effective date 7/1/23; contract expires 12/31/25.
- **DOE National Nuclear Security Administration Sale** (Modeled as a Term Sale)**:** Up to 40 MW capacity, ~351 GWh/year in energy sales. Contract is effective from 1/1/24-12/31/25.
- **SRP Sale:** SPV 3 located in Arizona, 100 MW (Maximum Capacity) ~375 GWh/year. Effective Date 10/20/2003; Contract Expires 8/31/2036. In some of the modeled scenarios, Springerville 3 is retired before the end of the contract date. Tri-State cannot terminate operations of Springerville 3 and the related third-party contract without reaching agreement with impacted parties.

## Modeling of Proxy Sales

Tri-State modeled proxy sales for near-term years in anticipation of the ability to sell excess power upon Member exits. Proxy sales include:

- [redacted]
- [redacted]

In September 2023, Tri-State issued a reverse RFP and resulting potential sales are still under evaluation with some negotiations in progress.

## Generic Resource Availability

The model is able to select generic resources to be added in the expansion plan starting as soon as 2026, depending on lead time of each technology as identified in Attachment C-2 of the ERP Report (LKT-1).

## PPA and Contract Information

Modeling reflects PPA capacity, energy, and CoDs shown in Attachment C-1 of the ERP Report (LKT-1). Tri-State's modeling reflected known PPA updates, including:

- Escalante Solar commercial operation date (COD) was advanced from December 2024 to June 2024 based on updated project schedule. Escalante Solar was modeled through December 2043, the end of the Resource Acquisition Period.
- Axial Basin and Dolores Canyon are no longer PPAs and were modeled as Tri-State owned resources.[21]

[20] Tri-State is evaluating the potential to model these opportunities in Phase II of the 2023 ERP.
[21] See Attachment C-3 of the ERP Report (LKT-1). Also see Proceeding No. 23A-0548E.

After scenario modeling began, additional PPA changes occurred:

- Due to global supply chain and tariff uncertainties impacting construction schedules, the Coyote Gulch Solar PPA was terminated, effective October 1, 2023.[22]
- Additionally, due to similar reasons noted above, the price increased from [redacted] for the Spanish Peaks and Spanish Peaks II PPAs. Simultaneous to the price modification, the Spanish Peaks and Spanish Peaks II PPAs were also extended for four additional years, from a 2039 contract end date to 2043 (making them 19-year PPA terms).[23]

### SRP Contract

Salt River Project (SRP) is assumed to take at least the contract minimum capacity amount from SPV 3, but if the cost of SPV 3 energy is lower than forecasted market prices, the SRP take can be modeled above the contract minimum, up to the max contract capacity (100 MW).

### System Loss Factor

The transmission system loss factor is meant to represent an average of expected transmission losses as Tri-State load in the Western Interconnection is located across multiple BAs and Transmission Provider systems. The transmission loss factor used in the planning and dispatch models was 3.5% in the Wyoming, Western Colorado, and Eastern Colorado planning regions. A portion of transmission system losses are financial, and are recorded in the financial models as a purchase power expense.

## *Demand-Side Management*

### Demand Response

For the ECO and WCO planning regions, Tri-State models achievement of the "DR Target." The DR Target[24] requires Tri-State to "…develop in-house demand response offerings in Colorado by 2025 that are designed to control at least 4% of Tri-State's Colorado peak load." Tri-State bases its DR modeling on the programs it anticipates launching, which include controls for: water heaters and air conditioners for residential and small commercial settings, irrigation load, and commercial and industrial (C&I) applications. Tri-State also models Low DR for WYO-WNE and NM planning regions,[25] which is generally consistent with internally-forecasted levels of uptake of DR programs.

*Modeling the DR Target for ECO and WCO* involves the following input assumptions and parameters:

- DR Target of at least 4% MW is a must-take, not a selection in the model.
- There are five different "DR resource" types: (1) Commercial & Industrial (C&I), (2) Irrigation, (3) Residential Battery Energy Storage Systems (BESS), (4) Residential Air Conditioning (A/C), and

[22] The Coyote Gulch Solar PPA was cancelled subsequent to initiation of Phase I scenario modeling, and therefore was included in the modeling, with a July 2026 COD. Replacement capacity will be procured through 2023 ERP Phase II.
[23] These contract modifications occurred subsequent to initiation of Phase I scenario modeling.
[24] See 2020 ERP Phase I Settlement Agreement, section 3.11.8.
[25] "Low DR" is based on the DSM and EE Potential Study completed by MesaPoint Energy for the 2020 ERP, May 8, 2020.

18(5) Residential Water Heaters (WH). Each has different values for Max Capacity, Maximum Daily Energy, Maximum Annual Energy, and Payback Required.

- **Max Capacity** sets the daily maximum output for each DR resource;
- **Maximum Daily Energy (%)** sets the maximum capacity factor for each day, limiting daily output to this input capacity factor;
- **Maximum Storage (MWh)** sets the maximum amount of energy that can be stored at any given time; and
- **Maximum Annual Energy (%)** sets the maximum capacity factor for the year.
- **Payback Required (%)** sets the percentage rate at which the interrupted load requirements need to be replaced.

- DR resource costs assumed for meeting the DR Target for ECO and WCO, both programmatic and incentive costs, are included in each scenario's financial analysis (i.e., revenue requirements), applied across the "lifetime" of the DR resources. The costs were provided by Tri-State's DSM department.

DR is dispatched by the model by determining the most economical way to dispatch DR thus shifting load while adhering to the hourly constraints and payback requirements in a given hour, day, and season. For example, the C&I DR resource is able to be called on year-round, but only during hours 8-16 (nine hrs/day) up to 14.5 MW in 2030, but only up to 8.6 GWh/yr (6.8% of annual capacity), and only can dispatch six of the nine hours in a given day (6/24 = 25% of Maximum Daily Energy). Also, DR resources are modeled like a battery in that whatever demand energy is curtailed, some amount of payback is required. In the case of the C&I DR resource, a 50% payback is required, so, for example, in year 2030 if it curtails 8.6 GWh/yr, 4.3 GWh/yr is paid back.

*Modeling DR resources for WYO-WNE and NM* involves the following input assumptions and parameters:

- DR resources can be selected by the model for WYO-WNE and NM.
- All of the five DR resources together are one Project in Encompass with an associated capital cost (CapEx) based on the present value of the lifetime expenditures for that project. If the Project is the most economic choice for meeting system load needs then the Project is selected and the associated Capex is modeled as an expenditure and the DR resource parameters (Max Capacity, etc. noted above) are applied in the modeling.
- The costs associated with the selected DR resources for WYO-WNE and NM, both the programmatic and incentive costs, are included in each scenario's financial analysis (i.e., revenue requirements) applied across the "lifetime" of the DR resources. The costs were provided by Tri-State's DSM department.

Because much of DR reflects shifts in the time periods when energy is used, financial models – which focus on energy billed to members within a month – show DR energy impacts net of timing shifts.

## Energy Efficiency

ECO and WCO regions were modeled to achieve the EE Targets[26] of 0.35% in 2023, 0.5% by 2024, 0.75% by 2025, and 1% by 2030 in incremental annual energy efficiency savings for Colorado Utility Member

[26] *See* 2020 ERP Phase I Settlement Agreement, Section 3.11.9.

system load.[27] See table below for estimated energy equivalents for EE Targets based on the latest load forecast.[28] WYO and NM regions were allowed to select Achievable-Low EE[29] starting in 2025.

*Table 9: Colorado Energy Efficiency Targets and GWh Equivalent*

| Target Year | EE Target (%) | Est. GWh Equivalent |
|---|---|---|
| 2023 | 0.35% | 39.0 |
| 2024 | 0.50% | 145.6 |
| 2025 | 0.75% | 59.0 |
| 2030 | 1.00% | 73.4 |

## *Environmental*

### Emission and Water Use Rates

Emission rates (lbs/MWh) and water use (gal/MWh)[30] for existing units were updated based on 2022 actual emissions, water use, and net generated MWh for each generator. Emissions rates and water use for generic thermal resources were reviewed and updated by B&V in Spring 2023. Emission rates and water use for innovative technologies were based on industry research and developer specs, where available. Emission and water use rates used for 2023 ERP Phase I modeling are shown in the table below. Also see Attachment C-2 of the ERP Report (LKT-1).

*Table 10: Emission and Water Use Rates*

| | $CO_2$ | $SO_2$ | NOx | Hg | PM | VOC | Water Usage |
|---|---|---|---|---|---|---|---|
| UNIT | lbs per Net MWh | lbs per Net MWh | lbs per Net MWh | lbs per Gross MWh | lbs per Gross MWh | lbs per Gross MWh | (gal/MWh) |
| LRS 2 | 2489 | 1.414 | 1.693 | 0.00001 | 0.126 | 0.0325 | 685 |
| LRS 3 | 2489 | 1.414 | 1.693 | 0.000 | 0.126 | 0.0325 | 685 |
| Craig 1[31] | 2388 | 0.604 | 2.790 | 0.0000040 | 0.104 | 0.0021 | 573 |
| Craig 2 | 2388 | 0.526 | 0.801 | 0.0000038 | 0.117 | 0.0019 | 573 |
| Craig 3 | 2204 | 1.332 | 2.240 | 0.0000065 | 0.040 | 0.0299 | 573 |
| Springerville 3 | 2372 | 0.990 | 0.857 | 0.0000043 | 0.196 | 0.0325 | 548 |

[27] There were two minor inputs to energy efficiency that were incorrectly reflected in calculation of Colorado load for purposes of determining EE Targets in the modeling: 1) Partial Requirements deductions from total load started in 2025 instead of 2026; and 2) deductions for *all* Partial Requirements member elections were deducted from Colorado load requirements for purposes of calculating energy efficiency in the modeling, but should not have included non-Colorado partial requirements. The magnitude of this impact is immaterial, at less than a tenth of a percent.

[28] Page 27 of Tri-State's informational DSM plan filed in Proceeding No. 20A-0528E on September 1, 2022 contained EE Targets forecasted based on Tri-State Colorado system load at that time.

[29] Attachment G-3 of the ERP Report (LKT-1).

[30] Pursuant to Rule 3605(a)(IV)(I).

[31] NOx limits for Craig 1 are in place to comply with the Colorado State Implementation Plan related to the Regional Haze rule.

| | $CO_2$ | $SO_2$ | NOx | Hg | PM | VOC | Water Usage |
|---|---|---|---|---|---|---|---|
| **UNIT** | **lbs per Net MWh** | **lbs per Net MWh** | **lbs per Net MWh** | **lbs per Gross MWh** | **lbs per Gross MWh** | **lbs per Gross MWh** | **(gal/MWh)** |
| Burlington 1 | 2121 | 0.063 | 10.633 | *N/A* | 0.145 | 0.0050 | 10 |
| Burlington 2 | 2121 | 0.063 | 10.895 | *N/A* | 0.149 | 0.0051 | 10 |
| Pyramid 1 | 1232 | 0.010 | 1.394 | *N/A* | 0.074 | 0.0213 | 40 |
| Pyramid 2 | 1232 | 0.008 | 1.127 | *N/A* | 0.068 | 0.0205 | 40 |
| Pyramid 3 | 1232 | 0.017 | 1.285 | *N/A* | 0.079 | 0.0184 | 40 |
| Pyramid 4 | 1232 | 0.009 | 1.147 | *N/A* | 0.070 | 0.0207 | 40 |
| Limon 1 | 1594 | 0.009 | 0.294 | *N/A* | 0.067 | 0.0026 | 32 |
| Limon 2 | 1594 | 0.011 | 0.387 | *N/A* | 0.079 | 0.0028 | 32 |
| Knutson 1 | 1515 | 0.011 | 0.387 | *N/A* | 0.118 | 0.0008 | 17 |
| Knutson 2 | 1515 | 0.010 | 0.329 | *N/A* | 0.118 | 0.0008 | 17 |
| J. M. Shafer | 985 | 0.005 | 0.725 | *N/A* | 0.053 | 0.0465 | 343 |
| **Unspecified Energy Purchases** | **Years 2023 - 2029** | | | | | | |
| Basin Nebraska | 996 | 0.981 | 0.822 | *N/A* | *N/A* | *N/A* | *N/A* |
| Basin Electric- CO/WY thru 2025 | 2596 | 1.299 | 1.443 | *N/A* | *N/A* | *N/A* | *N/A* |
| Basin Electric- CO/WY 2026-2029 | 1159 | 1.299 | 1.443 | *N/A* | *N/A* | *N/A* | *N/A* |
| Market Purchases | 1159 | 0.344 | 0.591 | *N/A* | *N/A* | *N/A* | *N/A* |
| Energy Imbalance | 1159 | 0.344 | 0.591 | *N/A* | *N/A* | *N/A* | *N/A* |
| **Gas Expansion Plan Units** | | | | | | | |
| 46_5x9RICE | 981 | 0.010 | 0.180 | *N/A* | 0.042 | 0.089 | 0 |
| 40_1x40LM6000 | 1089 | 0.011 | 0.084 | *N/A* | 0.069 | 0.027 | 40 |
| 200_1x235_7FA05 | 1165 | 0.012 | 0.090 | *N/A* | 0.073 | 0.029 | 57 |
| Natural Gas CCS | 765 | 0.008 | 0.046 | N/A | 0.048 | 0.019 | 348 |
| **Innovative Tech - Expansion** | | | | | | | |
| Blue Hydrogen w/CCS | 59 | | 0.19 | | | | 570 |
| Green Hydrogen | 0 | | 1.06 | | | | 357 |
| Nuclear SMR | N/A | | | | | | 672 |
| Geothermal EGS/Adv | N/A | | | | | | 100 |
| **Non-Emitting Technology with Water Usage** | *Note:* Net battery generation is negative; the negative water usage, when applied to negative generation, results in positive overall water usage for non-emitting technology with water usage. | | | | | | |
| 10 Hour Battery | *N/A* | *N/A* | *N/A* | *N/A* | *N/A* | *N/A* | 0 |
| Battery - Iron Air | *N/A* | *N/A* | *N/A* | *N/A* | *N/A* | *N/A* | -24.7 |
| Molten Salt Storage | *N/A* | *N/A* | *N/A* | *N/A* | *N/A* | *N/A* | -51 |
| Pumped Hydro | *N/A* | *N/A* | *N/A* | *N/A* | *N/A* | *N/A* | -412 |

## Emissions Reduction Targets

All portfolios are modeled to achieve at least the Interim-Year Emissions Reductions and 2030 Emissions Reduction Targets.[32] Also see Attachment B-3 of the ERP Report (LKT-1).

## APCD Workbook Inputs and Resource, Market & Contract Emissions Rates

As shown in Attachments D1-D5 to the ERP Report (LKT-1), the APCD Workbooks for each scenario, Tri-State's 2005 carbon emissions baseline reflects adjustments necessary to exclude Member Exits and Partial Requirements contracts from the baseline in relevant years. Details regarding Member Exits and Partial Requirements are described above, see *Load Forecast*.

Additionally, market and contract emissions rates were updated as follows:

- Basin Eastern Interconnection contract updated to 2021 eGRID MROW rates;
- Basin Western Interconnection contract updated to LRS emission rates for 2025, and 2021 eGRID RMPA rate for 2026 to 2029; and
- Market purchase and sales updated to 2021 eGRID RMPA and AZNM rates as applicable.

## Social Cost of Carbon

Social Cost of Carbon ("SCoC") is based on the latest values published by the Interagency Working Group (IWG) on the Social Cost of Greenhouse Gases, for calculating the net present value of carbon dioxide emissions, brought back to present value with a 2.5% discount rate.[33] The values, which are in 2020 real dollars, are inflated using the inflation rate assumptions used throughout the ERP.

## Social Cost of Methane

Social Cost of Methane ("SCoM") is based on the latest values published by the IWG on the Social Cost of Greenhouse Gases, for calculating the net present value of methane emissions, brought back to present value with a 2.5% discount rate.[34] The values, which are in 2020 real dollars, are inflated using the inflation rate assumptions used throughout the ERP.

[32] See 2020 ERP Phase I Settlement Agreement, Sections 3.3.4 and 3.3.5.
[33] The IWG has not published an update to SCoC values or the discount rate since February 2021.
[34] The IWG has not published an update to SCoM values or the discount rate since February 2021.

BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

| | |
|---|---|
| Federal Power Act Section 202(c) | ) |
| Emergency Order: Tri-State | ) |
| Generation and Transmission | ) |
| Association, Platte River Power | ) |
| Authority, Salt River Project, | ) |
| PacifiCorp, and Xcel Energy | ) |

Exhibit to
Motion to Intervene and Request for Rehearing and Stay of
Public Interest Organizations

Exhibit 2-62:
NERC Electrochemical Storage Study

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

# Energy Storage

## Impacts of Electrochemical Utility-Scale Battery Energy Storage Systems on the Bulk Power System

February 2021

RELIABILITY | RESILIENCE | SECURITY






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Atlanta, GA 30326
404-446-2560 | www.nerc.com

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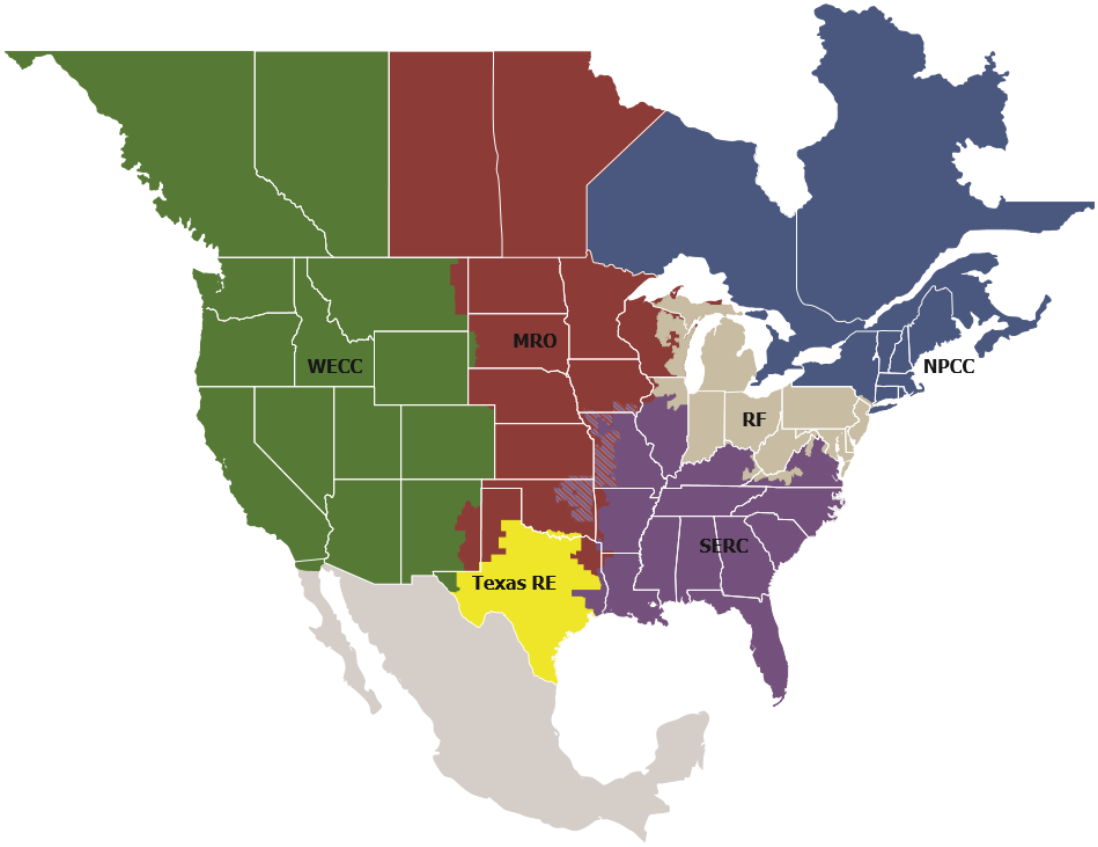
# Preface

Electricity is a key component of the fabric of modern society and the Electric Reliability Organization (ERO) Enterprise serves to strengthen that fabric. The vision for the ERO Enterprise, which is comprised of the North American Electric Reliability Corporation (NERC) and the six Regional Entities (REs), is a highly reliable and secure North American bulk power system (BPS). Our mission is to assure the effective and efficient reduction of risks to the reliability and security of the grid.

**Reliability | Resilience | Security**

*Because nearly 400 million citizens in North America are counting on us*

The North American BPS is made up of six RE boundaries as shown in the map and corresponding table below. The multicolored area denotes overlap as some load-serving entities participate in one RE while associated Transmission Owners/Operators participate in another.




| | |
|---|---|
| **MRO** | Midwest Reliability Organization |
| **NPCC** | Northeast Power Coordinating Council |
| **RF** | ReliabilityFirst |
| **SERC** | SERC Reliability Corporation |
| **Texas RE** | Texas Reliability Entity |
| **WECC** | WECC |

# Executive Summary

The electricity sector is undergoing significant and rapid changes that present new challenges and opportunities for reliability, security, and resilience. NERC has recently conducted analyses that underscore challenges presented with the acceleration of coal-fired generation retirements and the increased reliance on natural gas. Additionally, NERC continues to note a rapid shift to inverter-based resources (IBRs) that are variable energy resources due to their fuel source (e.g. wind, solar) and have different operating characteristics from traditional synchronous generation. This variability creates potential challenges related to availability that may require additional resources to maintain BPS reliability. NERC has pointed to these topics in past assessments. Furthermore, NERC continues to emphasize the importance of ensuring that these IBRs provide essential reliability services (ERS) to the grid, such as frequency response, ramping, and voltage support. Along with this increase in IBR, primarily from the addition of a large contribution of renewable resources (e.g., wind, solar), there has been an increase in the application of battery energy storage systems (BESS) on the BPS. BESS have the ability to complement IBRs by providing some of the ERS that are important to maintain BPS reliability. Additionally, BESS provide elements of grid support, including providing flexible ramping support, fast frequency response (FFR), addressing the uncertainty of resource availability, and shifting energy to address new peaking conditions.

NERC recently conducted a joint study with WECC that underscored some of the potential benefits BESS can provide for FFR to avert using under frequency load shedding (UFLS) in response to generation losses. Additionally, this assessment confirms projections that BESS will grow significantly across the North American footprint over the next twenty years.

**Key Findings:** Based on data and information collected for this assessment, NERC identified the following:

- BESS are projected to grow at an increasing pace across the North American footprint as shown in **Figure 2.1**.
- Lithium-ion batteries account for more than 50% of the installed power and energy capacity of large-scale electrochemical batteries. Flow batteries are an emerging storage technology; however, it still constitutes only 2% of the market.
- Advances in technology, decreasing costs, and changes to FERC and other market rules will promote BESS growth.
- As IBRs (primarily from wind and solar resources) continue to grow, BESS can enhance grid reliability by offsetting resource variability and providing ERS, such as voltage support and frequency response. NERC's inverter-based working group (IBRWG) continues to develop appropriate guidelines addressing potential impacts of IBRs.[1]
- A joint NERC/WECC study determined that BESS strategically located provide effective and FFR to avert UFLS.
- Existing NERC standards adequately reflect battery storage as a generator, ensuring that the NERC TPL and MOD standards are applicable to the current number of BESS on the BPS.
- Data on battery storage tends to be non-uniform and lacking in consistency across reporting entities necessitating a need for better reporting mechanisms for BESS data.
- Because battery storage is an emerging technology, the development of utility-scale battery storage has lagged the integration of renewable resources.

**Recommendations:** Based on the identified Key Findings previously mentioned, NERC has formulated the following recommendations:

[1] IBRWG homepage

- System planners should prepare for a significant increase in the critical mass of BESS across the North American footprint. Planners must ensure that deployed battery storage provides the necessary ERSs to maintain BPS reliability, security, and resilience.
- As regulators provide more incentives for the viability of battery storage to provide capacity and energy, system planners must adequately plan the system for a projected large increase in BESS, understanding the impact of size, location, and operating characteristics on maintaining the reliable operation of the grid.
- The value of battery storage as a complement to variable energy resources, such as wind and solar, should be fully understood by system planners and operators. System planners must conduct adequate studies to determine the dynamic stability impacts of BESS' Interconnection, the capability to provide capacity to meet long-term and contingency reserve margin requirements, and the ability to provide ERS.
- NERC should conduct a detailed analysis of existing NERC Reliability Standards and guidelines to ensure that they adequately provide for a large increase in the critical mass of BESS, conduct a gap analysis to ensure that existing standards are not deficient, and/or identify the need for new standards to reflect the potential large increase in BESS.
- Entities that compile battery data information must enhance both their data collection methods as well as their reporting methods. As energy storage systems become more prolific, accurate and timely data will be essential for both system planners and operators. The Institute of Electrical and Electronics Engineers (IEEE) should update the IEEE Standards to reflect any implications of battery storage systems. The GADS Working Group should ensure that battery storage is accurately reflected in their data capturing protocols.
- The NERC Reliability and Security Technical Committee (RSTC) should form a task force to study the forward-looking implications of BESS and their overall effects on BPS reliability and resilience.

# Introduction

NERC, in its mission to maintain the reliability of the BPS, continues to assess the implications on the reliability, security, and resilience from integration of cutting-edge technologies to the electrical grid. Due to the changing nature of the grid and the increasing amount of projected BESS in the future, the industry and regulators must pay more attention to BPS-connected BESS units.

## What is a Battery?

The collective contribution of scientists and innovators created our understanding of the forces of electricity, but Alessandro Volta developed the first electrical battery in 1799.[2] This battery, known as the Voltaic Cell, consisted of two plates of different metals immersed in a chemical solution. He discovered that electricity can be generated chemically and made to flow evenly through a conductor in a closed circuit.

The basic power unit inside a battery is a cell, and it consists of three main parts. There are two electrodes (electrical terminals) and a chemical called an electrolyte in between them. The negative electrical terminal is the anode, and the positive electrical terminal is the cathode. Electrolytes allow ions to move between the electrodes and terminals allowing current to flow out of the battery to perform work. For our convenience and safety, these cells are usually packed inside a metal or plastic outer case. The difference between a battery and a cell is simply that a battery consists of two or more cells hooked up so their power adds together (**Figure I.1**).

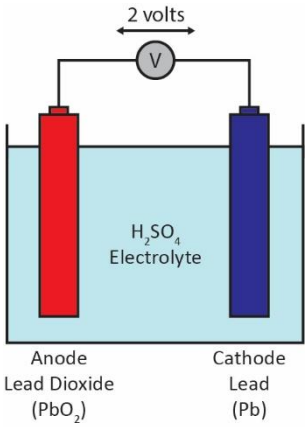



**Figure I.1: Schematic of a Battery**

Advances in technology and materials have greatly increased the reliability, output, and density of modern battery systems, and economies of scale have dramatically reduced the associated cost. Continued innovation created new technologies, like electrochemical capacitors, which can quickly charge or discharge energy for later use and provide an almost unlimited operational lifespan. Two emerging technologies in electric energy storage are**: Lithium-Ion and Flow** Batteries as described in this report; these two electrochemical technologies offer a more robust and adaptable energy grid, as shown in **Figure I.2**.

The scope of this report will include stand-alone BESS and BESS connected alongside other generation resources.[3] The BESS in scope for this assessment are BPS-connected with a primary emphasis on lithium-Ion and flow batteries. The fastest growing technology is the lithium-Ion market, which is largely driven by the electric vehicle (EV) market.

In recent years, the use of BPS-connected battery energy storage has quadrupled from 214 MW (2014) to 899 MW (2019), and NERC anticipates that the capacity could exceed 3,500 MW by 2023 (**Figure I.3**).

[2] https://ethw.org/Milestones:Volta's_Electrical_Battery_Invention,_1799

[3] This BESS configuration, referred to as hybrid resources, is typically a BESS with solar or a BESS with wind.

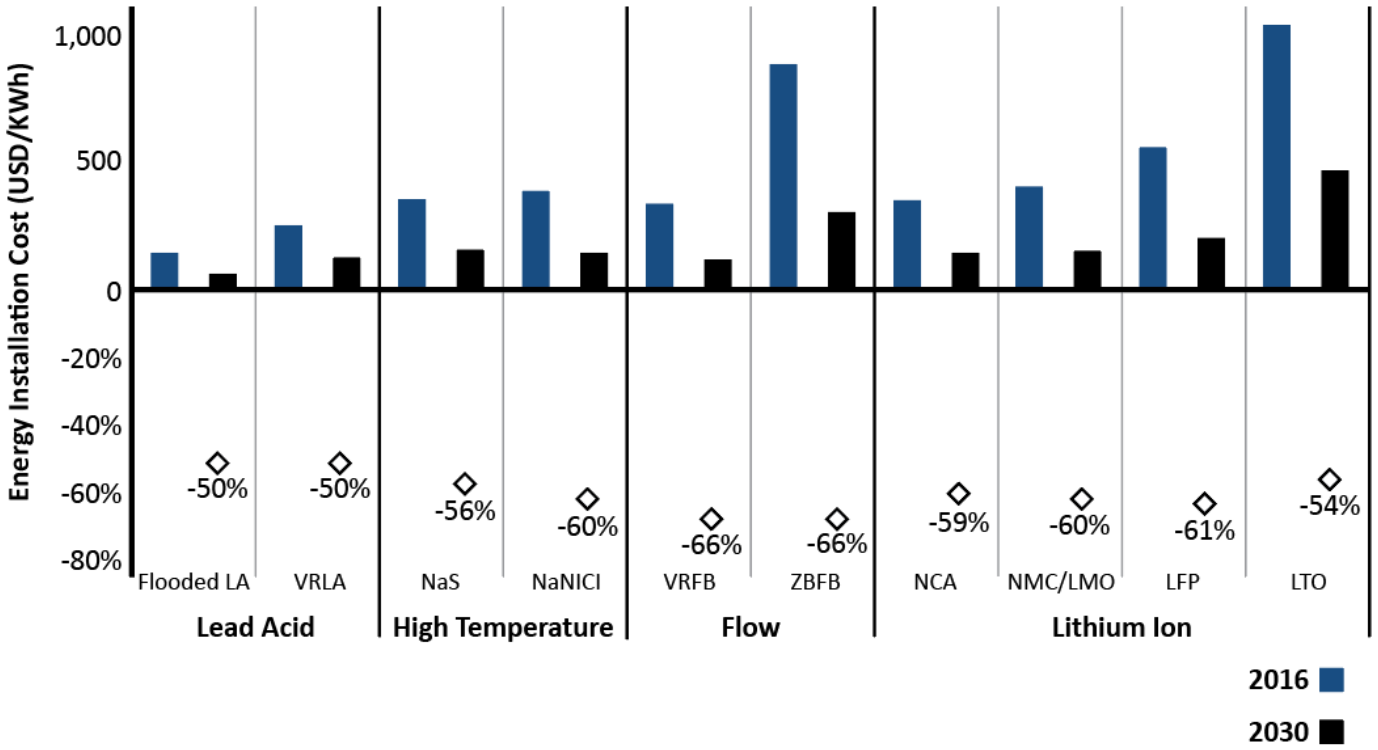



**Figure I.2: Energy Installation Costs Central Estimate for Battery Technologies, 2016–2030**
(The diamond represents the decrease in installation cost when comparing 2016 to 2030 data)

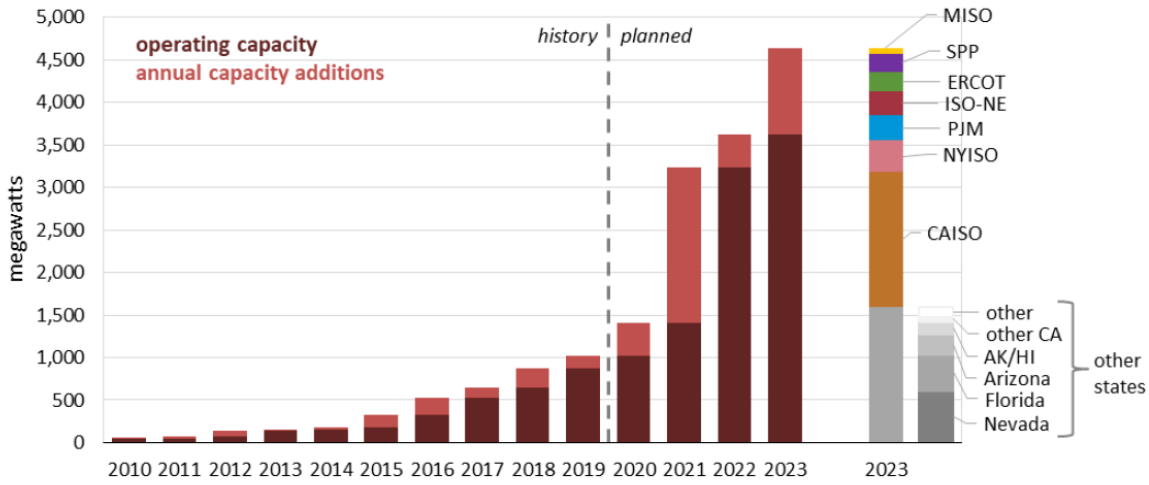



**Figure I.3: United States BPS-Connected Battery Energy Storage Power Capacity (July 2020)[4]**

One of the major growth areas for BESS is in hybrid systems. An example of a hybrid system is the combination of a wind or solar plant alongside a BESS facility. Internationally, a wind farm in South Australia retains the biggest-battery title at 100 MW/129 MWh, which is enough to supply 30,000 homes for eight hours. The largest battery in the United States and the world is projected to come online in 2021 when Florida Power and Light's 409 MW/900 MWh Manatee (center solar plant) Energy Storage Center becomes operational. Furthermore, Southern California Edison has just

[4] July 2020, U. S Energy Information Administration, Form EIA-806M, Preliminary Monthly Electric Generator Inventory

finalized what analysts called the nation's largest-ever purchase of battery storage in late April 2020, and this mega-battery storage facility is rated at 770 MW/3,080 MWh. The largest battery in Canada is projected to come online in 2021 when Alberta's TransAlta Renewables WindCharger's 60 MW utility-scale battery project becomes operational.[5]

The top four states that have operating or facilities under construction are California, Illinois, West Virginia, and Texas; these four states make up over half of the total installed battery storage in the United States, as shown in **Figure I.4**.

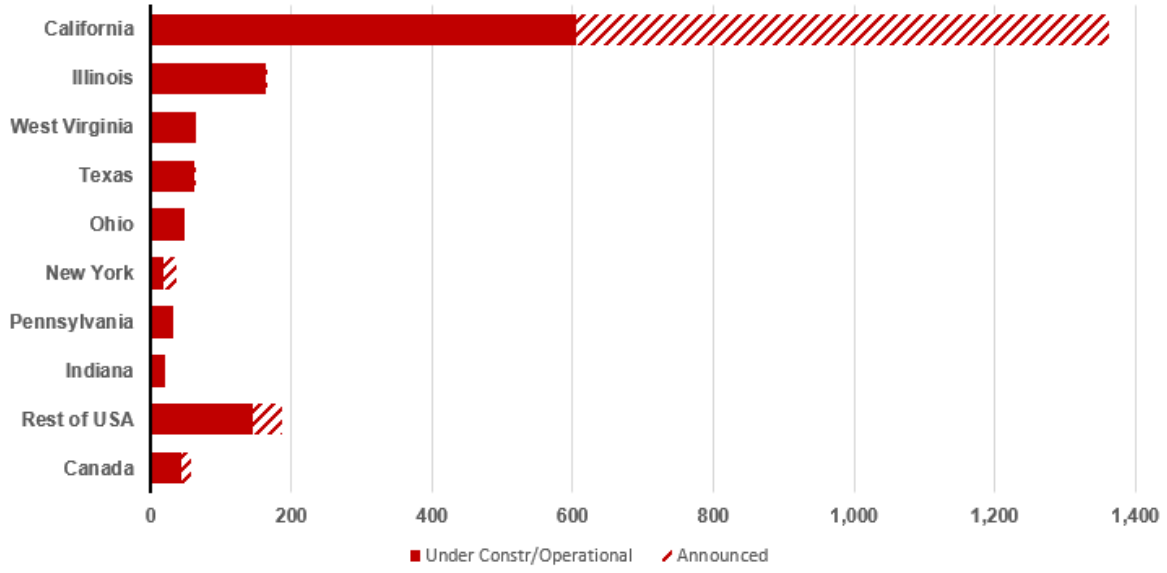



**Figure I.4: United States Operating Utility-Scale Battery Storage by State[6]**

**Figure I.5** shows an electric power profile with its variations during a 24-hour period. In a load-leveling scenario, the BESS charges during periods of low power demand and discharges during periods of high power demand. Overall, the utility would need less capacity to meet this now lowered demand at its peak and could delay the installation of additional generating capacity. Such energy shifts help to regulate the generation and load balance. Energy storage would help to enable the delivery of energy for a limited amount of time when variable renewable energy sources, such as solar photovoltaic (PV) and wind, are not available.

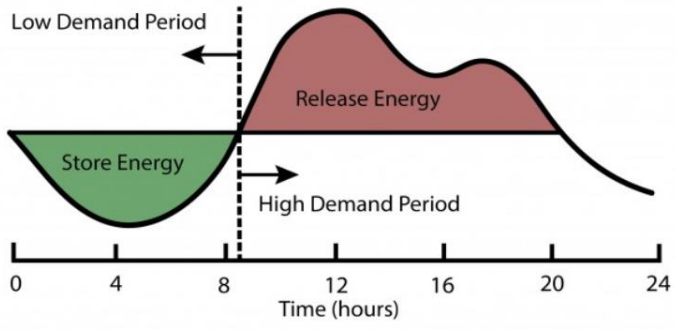



**Figure I.5: Daily Energy Storage and Load Leveling[7]**

[5] The first 20 MW is operational by December 2020, the final two 20 MW will come online in 2021; https://www.teslarati.com/tesla-canada-biggest-battery-energy-storage-system/

[6] Graph adapted from the DOE website, "DOE Global Energy Storage Database", Energy Storage Exchange, www.energystorageexchange.org.

[7] University of Michigan, http://css.umich.edu/factsheets/us-grid-energy-storage-factsheet

There are other applications and locations for BPS-level BESS. The three main demands that this technology is used for are operating reserves and ancillary services: energy arbitrage, curtailment reduction and load leveling, and peaking capacity.

While the daily energy storage and load-leveling example show a typical BESS applications case, the following sections summarize the most common applications for the growth of BESS in the power industry. These applications will dictate the operational characteristics of BESS.

## Key Characteristics and Definitions of BESSs

Storage technologies have a few key characteristics that can be useful for comparison. Some of the key characteristics used by the industry are summarized below. These characteristics can be further defined and customized for each energy storage technologies.

Different battery technologies have an inherent state of charge (SOC), voltage currents, and temperature ranges that when operated within avoids accelerated cell degradation and safety issues.

### *Definition*

A battery energy storage system (BESS) is a term used to describe the entire system, including the battery energy storage device along with any ancillary motors/pumps, power electronics, control electronics, and packaging. Since all electrochemical batteries produce dc current, a BESS typically consists of the following components:

- The dc battery system (batteries, racks, etc.)
- Enclosure(s) with thermal management
- Bi-directional dc/ac inverter
- EMS/system level software controller
- Switchgear/metering/MV step-up transformer, etc.

### *Rated Power Capacity* *(citation, Grid-Scale Battery Storage, FAQ)*

The total possible instantaneous discharge capability, in kilowatts (kW) or megawatts (MW), of the BESS or the maximum rate of discharge that the BESS can achieve that starts from a fully charged state.

### *Rated Energy Capacity*

The amount of energy stored in the battery, in kilowatt-hours (kWh) or megawatt-hours (MWh).

Rated energy capacity can be specified in ac terms (kWh) for complete systems, including energy storage medium, power conversion electronics, and transformers. Alternatively, it can also be specified in dc terms (MWh) when only the battery or energy storage medium is represented or considered. Additionally, vendors will sometimes show a “rating” for kWh in dc without or before considering ac conversion. When this is done, it is critical to remember that the power capacity of the system is normally determined by the capability of the power electronics, not just the energy storage medium, since the ac rating of a battery system may be significantly smaller than the dc rating of the battery component itself, due to the inefficiency of energy conversion.

Some manufacturers will specify a “rated power” but then list a “maximum depth-of-discharge” (DOD) that limits the actual energy available. For some technologies, the energy available may be proportional to the discharge rate and temperature (higher discharge rates typically allow less energy to be removed from the battery).

### *Storage Duration*

Storage duration is the amount of time the energy storage can discharge at the system power capacity before depleting its energy capacity. For example, a rated battery with 1 MW of power capacity and 4 MWh of usable system energy capacity will have a reserve duration of four hours at a specified discharge rate.

### *Cycle Life*

This characteristic is specific to the battery/energy storage medium. Cycle life is the number of times the battery can be discharged and recharged during its useful life over a specific SOC range. Cycle life is often specified as number of cycles to a specific depth of discharge (DOD) since many batteries will have a longer life if discharges are kept shallow. This assumes that cycle life is directionally proportional to DOD and is equivalent to something like 5,000 cycles to 50% DOD or 2,500 cycles to 100% DOD. This may not be the case for some battery types and chemistries. There is an increasing trend to provide warranties based on "energy throughput." This is derived by the summation of the total amount of energy a battery is expected to deliver over its lifetime (e.g., the number of kWh, stored energy delivered by the battery). This term is universal and can be apply to all types of batteries no matter what their degradation mechanism or rate is over time.

### *Self-discharge*

Self-discharge occurs when the stored charge (or energy) of the battery is reduced through internal chemical reactions or without being discharged to perform work for the grid or a customer. Self-discharge, expressed as a percentage of charge lost over a certain period, reduces the amount of energy available for discharge and is an important parameter to consider in batteries intended for longer-duration applications.

### *State of Charge*

SOC, expressed as a percentage, represents the battery's present level of charge and ranges from completely discharged to fully charged. The SOC influences a battery's ability to provide energy or ancillary services to the grid at any given time. Different battery technologies have an inherent SOC range that, when operated within, avoids accelerated cell degradation. The achievable high and low SOC values are specific to a battery chemistry and type.

### *Round-trip efficiency*

Round-trip efficiency, which is measured as a percentage, is a ratio of the energy charged to the battery to the energy discharged from the battery. It represents the total efficiency of the battery system to resupply energy taken from its source, including losses from self-discharge. Although battery manufacturers often refer to the dc-dc efficiency (i.e., round-trip efficiency from the dc charge controller) and do not include the losses due to required subsystems, such as HVAC, natural gas detection, and fire protection. In contrast, ac-ac efficiency (i.e. the round-trip efficiency from the point of interconnection) includes all system losses that are typically more important as it measures the battery as it is charging and discharging from the point of interconnection to the power system, which uses ac (Denholm 2019).

### *System Life*

This is the expected calendar life of the BESS used for its designed purpose and intent, also known as installation life. The system life incorporates the expected service life, degradation mechanism, and rate of all subcomponents for an application or use case. This includes but is not limited to the following: battery, electronics, power conversion, and interconnection equipment. Typically, this term is used only for the battery degradation, which may be a factor of cell corrosion, capacity degradation, life of seals/membranes, or other factors. If designed and installed properly, battery degradation is truly dependent on how an end user operates their system. Battery applications are typically broken up into two categories: energy and power. Energy applications can include time shift, supply capacity, and spinning reserves. Power applications are typically load ramping and/or following voltage support and frequency response. Because energy response typically has a deeper depth of discharge on a consistent basis, these applications have a steeper degradation curve for some chemistries.

Using the battery outside its designed purpose may affect its capabilities and life. Changing or modifying the use case, cycle frequency, DOD, charge/discharge parameters, or rate will affect the warranty of the battery and may exceed the battery or the power electronic capabilities. Entities should contact battery manufacturers and evaluate any effects of changing the use case from the original design before making changes to installations or subcomponents.

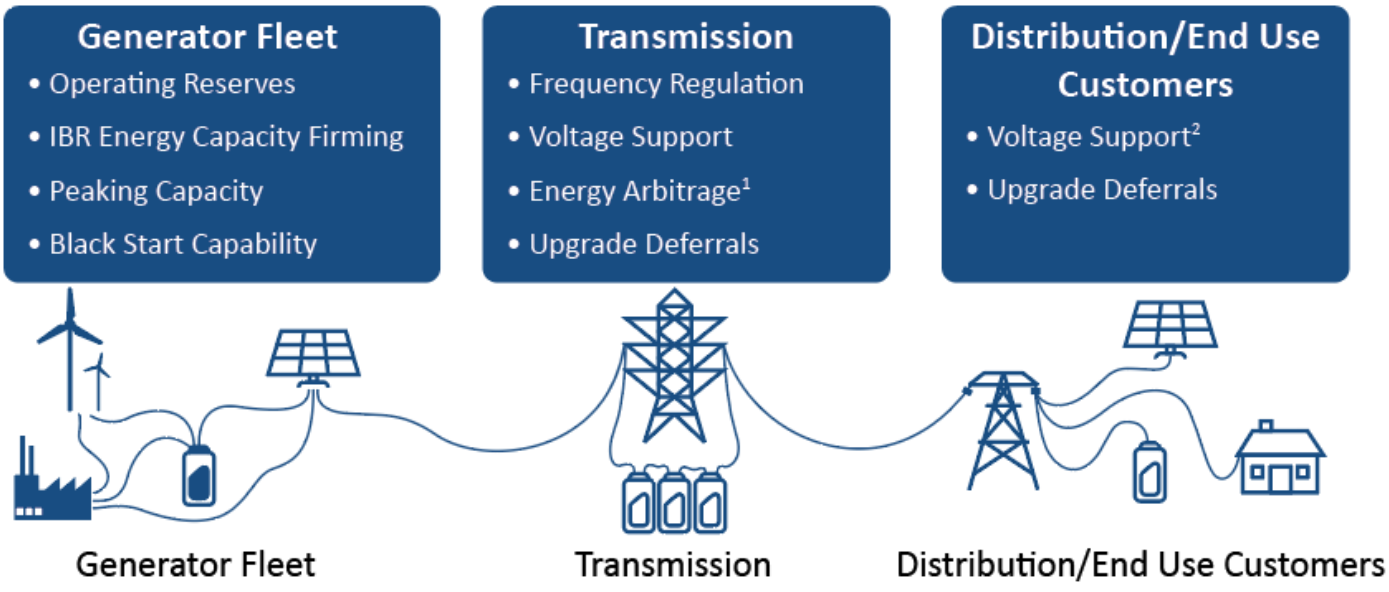
### *Safety*

If used incorrectly, all batteries become a risk and can pose a danger to the equipment and personnel. The higher the energy density of the battery means the more attention to the design, maintenance, and operation of the BESS is required.

# Chapter 1: Applications of Battery Energy Storage for the Grid

BESS are an well suited technology to provide short-term grid contingency support (tens of seconds) and long-term energy support/reserve (up to four hours) with the BESS capable of short settling times and the operational flexibility inherent to energy storage. BESS can provide the ERS of frequency regulation, ramping, and voltage support in a manner that can replicate current levels of ERS from synchronous facilities. In addition, BESS can also provide ancillary services with several hours of energy capacity reserve ready for the grid. The main BESS applications in power system generation, transmission, and operation are described in **Figure 1.1.**[8]

Batteries can provide services for system operation and for solar PV and wind generators as well as defer investments in peak generation.




[1] This term is related to the load-leveling term commonly found in nonmarket solutions. They both effectively look to have similar battery performance by shifting energy to different times.

[2] While not commonly used for distribution systems, BESS can perform their voltage support on the distribution system. It is expected that most BESS that provide voltage support will be placed on the transmission system.

**Figure 1.1: Main Battery Applications in the Grid[9]**

The following section identifies the major reported services BESS are providing.

## Operating Reserves and Frequency Regulation

The ability to maintain specified reserves and/or adequate reserves beyond the firm system demand describes the function of operating reserves. Operating reserves consist of attributes like regulation, load following, and contingency reserves (spinning, non-spinning, and supplemental).[10] BESS can provide the regulation and load following capability to supply/absorb additional energy for the unexpected grid energy imbalance, or they can provide ramping capability of the grid during times of major load shifts.[11] With provided flexible ramping capability,

[8] https://www.irena.org/-/media/Files/IRENA/Agency/Publication/2019/Sep/IRENA_Utility-scale-batteries_2019.pdf

[9] IBR in **Figure 1.1** are inverter-based resources.

[10] https://www.nerc.com/comm/Other/essntlrlbltysrvcstskfrcDL/ERSTF%20Concept%20Paper.pdf

[11] These are typically the morning, afternoon, and evening times that are exacerbated by high solar PV penetration.

BESS can help BAs respond to large ramps during the day and reduce any ramping rate requirement of other resources.

BESS can also provide the grid primary frequency response (PFR). BESS have FFR capability as a full-converter type of power electronic device that, if enabled, allows the BESS to provide a large power injection before most conventional generation. These two functions, PFT and FFR, are short-term reliability services. BESS can also provide longer-duration frequency services with the stored energy that can provide grid the secondary frequency response or tertiary frequency response.

### Voltage support

Generating facilities are required to provide reactive power to the grid as called for in NERC's Reliability Standards. BESS can provide the reactive needed to support grid voltage stability on the transmission system. BESS can be a reactive resource to provide local voltage support acting as a transmission asset that similar to shunt reactive devices,[12] such as capacitor, static VAR Compensator (SVC), capacitors, or other power electronic controlled devices. This can occur independently from or in parallel with their frequency regulation service.

### Inverter-Based Resources (IBR) Energy Capacity Firming

Renewable energy resources, such as wind plants and solar PV, are variable energy resources as their "fuel source" is inherently variable (wind speed and solar irradiation). BESS can support renewable energy resources by providing energy during times of intermittent or expected unavailability (i.e., at times when the wind speed drops for wind generation or at night for solar PV). The addition of BESS can result in a higher capacity factor for the hybrid system.

### Peaking Capacity

BESS can discharge energy at the peak loading conditions to meet the peak demand as well as provide peaking generation capacity replacing the need to use high cost natural gas plants that have historically been dispatched during peak seasons. Furthermore, BESS can ameliorate congestion issues and serve as a substitute for peak shaving.

### Energy Arbitrage

BESS can take the advantage of different energy market prices by charging battery during low price hours and discharging during peak price hours.

### Transmission and Distribution Upgrade Deferrals

When the peak electricity demand exceeds the existing electricity grid's transmission and distribution capacity, the grid's infrastructure should be upgraded to deliver energy to the end-use customer or demand response options explored. However, these upgrades can be expensive to meet a limitation that may only occur for a few hours of the year.

BESS can help alleviate the peak demand stresses on the system. BESS can reduce grid congestion and improve overall transmission and distribution asset use especially with mobile BESS that can be BESS relocated to new areas when they are no longer needed in the original location.

### Blackstart Capability

Following a power system blackout, system blackstart capability serves to provide an initial start-up power supply for the other synchronous generators restoration and re-energize the transmission system without normal grid support. A BESS can be a potential blackstart resource as the stored energy lasts hours and can provide initial start-up power for itself and other generation facilities.

[12] Shunt reactive devices are a parallel pathway to ground in order to provide a service to the electricity grid, typically on managing reactive power. These are different from series-connected resources.

**Figure I.2** shows the cumulative installed capacity (MW) for BPS-connected storage systems in the United States in 2019 by the service the systems provide. Operating reserves and ancillary services make up a large portion of these MWs of cumulative installed capacity.

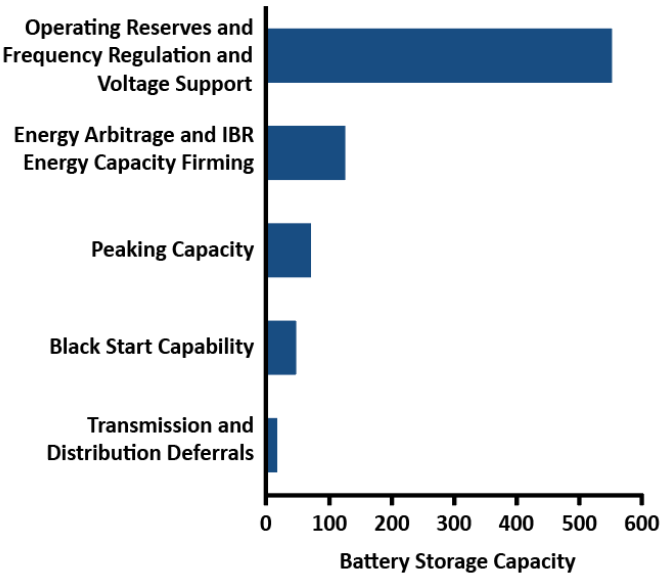



**Figure 1.2: United States BPS-Connected Battery Energy Storage Capacity by Service[13]**

## Status of Rated Power (MW) and Energy (MWh)

The impact that BESS can have on the future sustainable energy grid is substantial. As of September 2020, the United States and Canada had over 37 GW of rated power in energy storage with 90% coming from pumped hydro (**Figure 1.3**). The remaining 10% is from lithium-ion, thermal storage, compressed air, flywheel, lead batteries, and flow batteries. The most dominant electrochemical storage technology is lithium-ion, which accounts for about half the installed rated power.

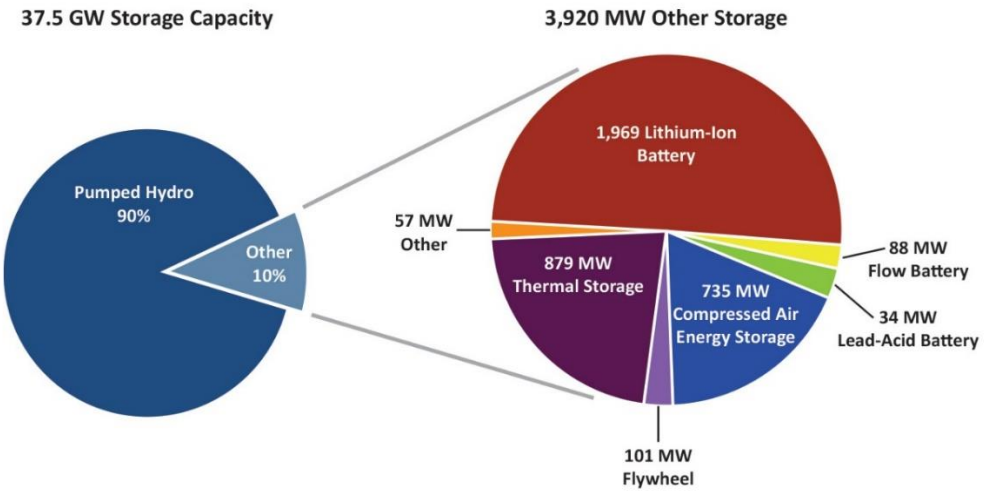
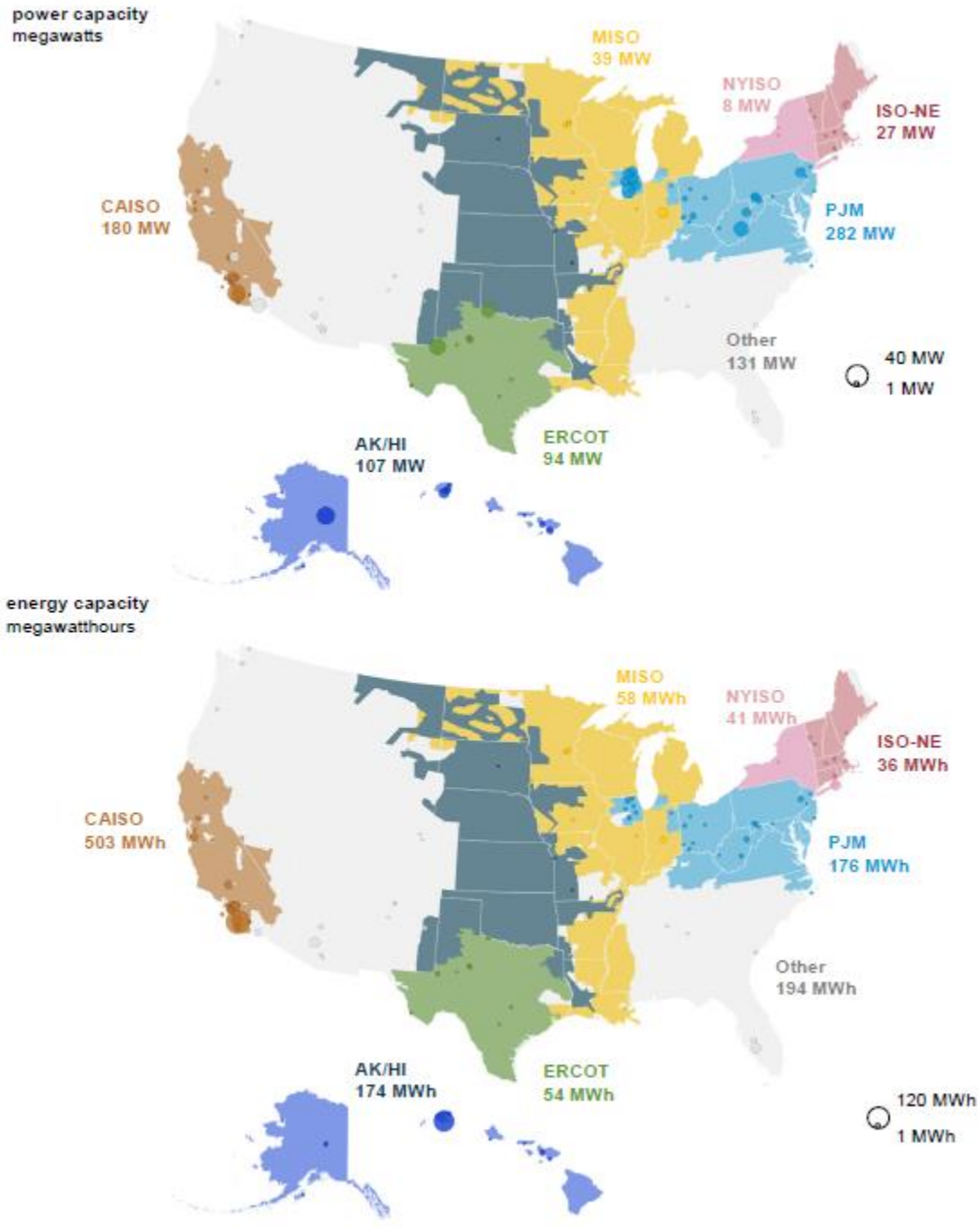



**Figure 1.3: Electric Storage Capacity in the United States and Canada, by Type of Storage Technology[14]**

[13] https://www.nrel.gov/docs/fy19osti/74426.pdf

[14] Graph adapted from the DOE website, "DOE Global Energy Storage Database," Energy Storage Exchange, www.energystorageexchange.org.

Another view of battery storage technologies across the regulated ISO/RTO markets is shown in **Figure 1.4**. Power capacity (MW) is 282 MW for PJM, 180 MW for CAL-ISO, and 94 MW for ERCOT; the energy capacity (MWh) is 176 MWh for PJM, 503 MWh for CAL-ISO, and 54 MWh for ERCOT.




Sources: U.S. Energy Information Administration, Form EIA-860M, *Preliminary Monthly Electric Generator Inventory;* U.S. Energy Information Administration, Form EIA-860, *Annual Electric Generator Report* Note: Energy capacity data for large-scale battery storage installed in 2018 are based on preliminary estimates.

**Figure 1.4: United States Grid-Connected Energy Storage Projects**

BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

| | |
|---|---|
| Federal Power Act Section 202(c) | ) |
| Emergency Order: Tri-State | ) |
| Generation and Transmission | ) |
| Association, Platte River Power | ) |
| Authority, Salt River Project, | ) |
| PacifiCorp, and Xcel Energy | ) |

Exhibit to
Motion to Intervene and Request for Rehearing and Stay of
Public Interest Organizations

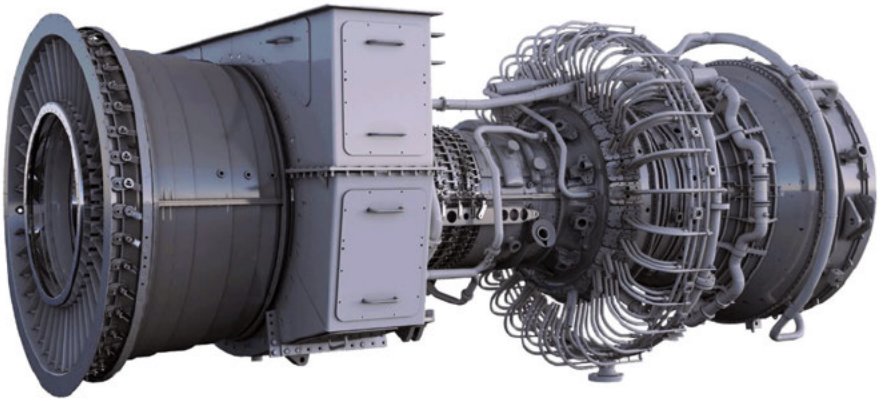
Exhibit 2-63:
GE LM6000 Information

# LM6000 aeroderivative gas turbine

A leader in the +40 MW space, the LM6000* has over 40 million operating hours and more than 1,200 units shipped.

View product specifications

Download LM6000 fact sheet



| ~57 MW | 41% | Over 99% | 5 min. | 100% |
|---|---|---|---|---|
| SC output | SC efficiency | reliability/availability | start time | H2 capable |

Overview

# LM6000 power plants

With over 40 million operating hours and more than 1,200 units shipped, GE Vernova's LM6000 aeroderivative gas turbine has more operating experience than any other aeroderivative gas turbine greater in the +40 MW space. The LM6000 offers greater than 99 percent start and operational reliability and over 98 percent availability. Its 5-minute fast start allows operators to differentiate their dispatch capability while a simple two-spool design results in lower overall maintenance costs. Universal and modular packaging gives the LM6000 a smaller footprint and allows for faster installation and commissioning.

Faster power to the grid

# Introducing the LM6000VELOX* aeroderivative solution

The new LM6000VELOX aeroderivative solution aims to reduce the installation and commissioning schedule of LM6000 turbines by up to 40%, saving up to 4,000 labor hours. This translates to an expected 90 days I&C schedule. Thanks to multiple enhanced modularity features, the LM6000VELOX aeroderivative solution is ushering in a new era of speed in the energy industry.

GE Vernova's LM6000VELOX aeroderivative solution is available:

- In both simple- and combined-cycle configurations.
- As either a DLE or SAC (water injected) combustor configuration.
- For both 50- and 60-Hertz segments.

See it in action

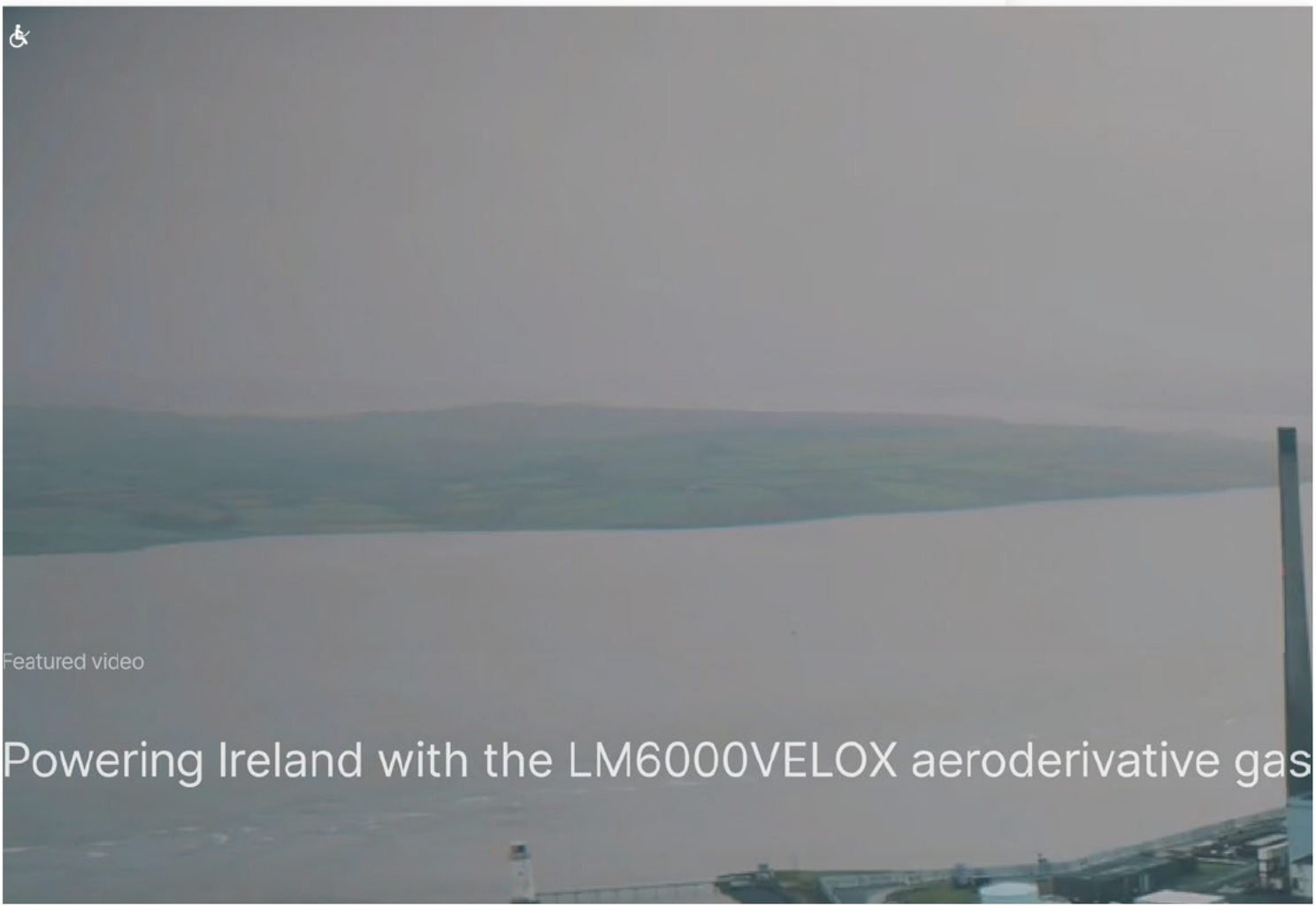
Highlight

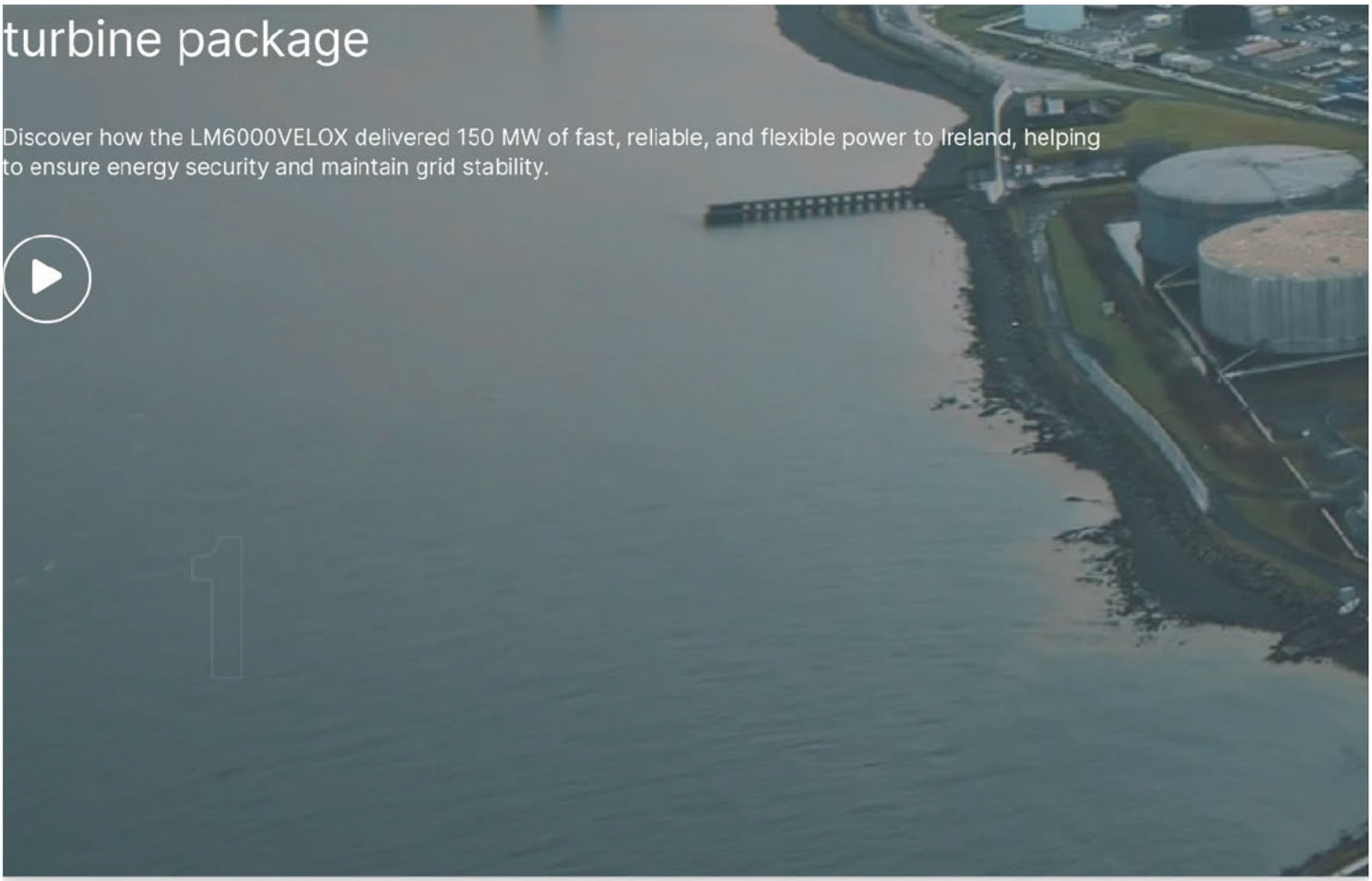
## Do you know about the Mark* VIe capabilities?

The Mark VIe is the latest GE Vernova control platform, with just some of its features including:

- Modular, future-ready engineering
- Legacy system integration
- Built-in cybersecurity
- Advanced diagnostics
- Developed for today's fuel demands

Learn more about the Mark VIe solution






Product features

# Get to know the LM6000

## Fuel flexibility

The LM6000 allows you to operate on a wide variety of fuels—including natural gas, LPG (propane and butane), isopentane, ethanol, diesel, and Coke Oven gas. This means you can quickly switch between fuels to save money, with no interruption in power. The LM6000 is 100% hydrogen capable.

## Fast start

Aeros like our LM6000 are built for high cycling capability, which allows customers to get up and running—and on the grid—quickly. With around five minutes to ramp up from start-up to full power, typical medium-speed reciprocating engines have a ramp rate of about 5 MW/min, but aeroderivative gas turbines have a nominal ramp rate of around 50 MW/min, providing a much faster frequency

## Spray intercooling (SPRINT*) performance augmentation

Our SPRINT* solution boosts engine performance using a spray intercooling design that increases the mass flow by cooling the air during the compression process. The system is based on an atomized water spray injected through spray nozzles. The water flow rate

control response for better grid support.

is metered, using the appropriate engine control schedules. SPRINT injection points are based on turbine inlet temperature and automatically controlled.

Specifications

## Capable, versatile, sustainable power

The LM6000 offers 99%+ start and operational reliability and 98% availability. Its 5-minute fast start allows operators to differentiate their dispatch capability, and its dual-fuel capabilities (gas and diesel) provides fuel flexibility and helps customers meet emissions limits.

Specifications shown are for 50 Hz and 60 Hz.

### Simple Cycle—

| | LM6000 PC Sprint | LM6000 PF+ Sprint |
|---|---|---|
| **Net output (MW)** | 51.1 | 56.9 |
| **Net heat rate (Btu/kWh, LHV)** | 8595 | 8328 |
| **Net heat rate (kJ/kWh, LHV)** | 9068 | 8800 |
| **Net efficiency (%, LHV)** | 39.7% | 41.0% |

### Combined Cycle 1×1+
### Combined Cycle 2×1+

LM6000 gas turbines can start up in 5 minutes

*MW output without SPRINT/with SPRINT

NOTE: All ratings are based on ISO conditions and natural gas fuel. Actual performance will vary with project-specific conditions and fuel.

Decarbonization hub

# Explore turbine emissions tools & studies



### Hydrogen & CO2 emissions calculator

Discover the fuel flow rate needed for hydrogen in gas turbines and explore potential savings from hydrogen use.



### Methane slip calculator

Compare unburnt methane amounts released from reciprocating engines vs. turbines and estimate emission reductions.



### Aeroderivative gas turbine solutions: A roadmap to 100% hydrogen capability

Get insights on how GE Vernova's advanced gas power technologies drive near-zero carbon, hydrogen solutions, and grid firming.



### Navigating the journey to decarbonization & grid stability

Explore how GE Vernova integrates aeroderivative solutions to stabilize renewables and our research green hydrogen potential.

Webinars

# Hear from our experts

AI-driven data centers | Aeroderivative gas turbines for munis & co-ops | Can you get more megawatts for your dollar?

Webinar

## Bridging the gap: Reliable power for AI-driven data centers

**On-demand | Available now**

AI is reshaping data center demand. Join GE Vernova, DataVolt and S&P Global to explore how to manage volatility, scale confidently, and build a resilient energy strategy.



**Donald Floyd**

Sr. Portfolio Manager-Gen AI, GE Vernova Advanced Research

Register to watch now

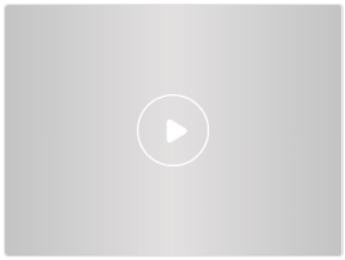
Discover

# Featured videos



**LM6000VELOX: Faster power to the grid**

With enhanced speed of installation, the LM6000VELOX can provide fast and reliable energy supply to help stabilize the grid when needed.



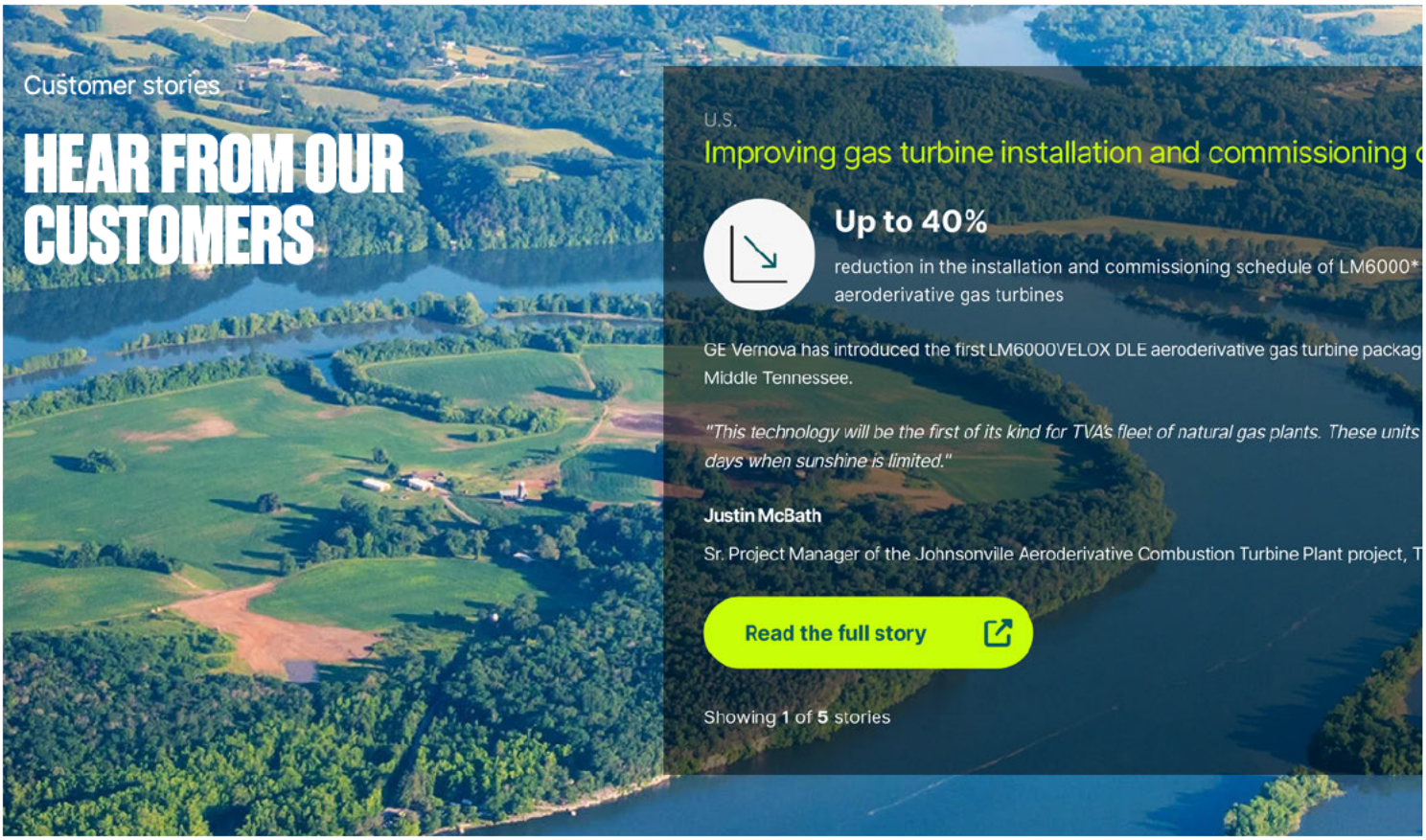
**LM6000VELOX DLE package installation**

Tennessee Valley Authority (TVA)'s Johnsonville Plant in Middle Tennessee is the site of GE Vernova's first LM6000VELOX DLE package solution.



**Keeping Houston's medical center lights on with the LM6000**

Discover how TECO and GE Vernova's partnership is driving reliability, availability and efficiency for the largest district cooling system in North America.




Services

# Get more from your LM6000 aero turbine

Our services team is prepared to meet your industry-specific requirements and provide more reliable aeroderivative gas turbine services whether you're looking for peaking power, flexible response to immediate grid demands, or simply to keep your operation up and running at a proven 99% rate of reliability.

## Upgrades

Our gas turbine upgrade solutions can boost performance and reliability, deliver better efficiency and flexibility, and extend asset life. Whether you need to upgrade your existing engine with our Repower solutions, or improve load balancing, you can explore our gas turbine upgrades tool.

Learn more

## Maintenance and repairs

From outages as short as two days—with module and engine exchanges—to customized off-season outages, equipment and engine leasing, upgrades, digital solutions and repairs, our network of global service centers and field service teams combine the highest quality of expertise

and technical aeroderivative gas turbine support with timely, flexible solutions and predictable repair costs.

Learn more

## Parts

Reliable plant operations depend on access to flexible parts service. Our global distribution centers are linked to regional supply chains, meaning you've got access to the highest-quality component inventory.

Learn more

## Long-term service agreements

Business environments are constantly transforming, but you need to deliver consistent outcomes. By partnering with us for long-term service agreements (LTSAs), you'll be able to realize the full potential of your gas plant.

Learn more

Further reading

# Learn more

## Explore

LM6000 gas turbine upgrades

GE Vernova's LM6000 powering Saudi Arabia's industries

Aeros vs. reciprocating engines

Gas turbines for municipalities and cooperatives

Benefits of cogeneration

Data center power solutions

Islands and Microgrids

## Downloads

LM6000 fact sheet

Aero fuel flexibility white paper

Products

# Find the right gas turbine to meet your needs

Whether you're generating; power for entire cities, electrifying your own operations, or are facing an emergency electricity shortage and need power fast, we can act as a versatile gas turbine supplier, ready to quickly provide a range of solutions.

View by type

All | Heavy duty | Aeroderivative

View by frequency

50Hz | 60Hz

View by configuration

Simple | 1×1CC | 2×1CC

| | | |
|---|---|---|
| 9HA | 448 - 571 MW | + |
| 9F | 294 MW | + |
| GT13E2 | 210 MW | + |
| 9E | 132 - 147 MW | + |
| LMS100 | 112.9 MW | + |
| 6F | 88 MW | + |
| LM6000 | 51.1 - 57 MW | + |
| 6B | 45 MW | + |
| LM2500 | 34.5 - 36.3 MW | + |
| TM2500 | 34.5 - 34.6 MW | + |

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Contact us today

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## Empowering the data-driven world with reliable, cleaner energy

GE Vernova's Gas Power business helps provide scalable efficient, infrastructure that supports the world's energy demands, including those of hyperscale and colocation data centers. Explore our products, from fuel-flexible turbines to services that keep reliable power flowing worldwide.

Explore our Gas Power data centers solutions


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| Federal Power Act Section 202(c) | ) |
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| Association, Platte River Power | ) |
| Authority, Salt River Project, | ) |
| PacifiCorp, and Xcel Energy | ) |

Exhibit to
Motion to Intervene and Request for Rehearing and Stay of
Public Interest Organizations

Exhibit 2-64:
Tri-State SPP West Press Release

# Benefits of SPP RTO West participation highlighted in filing with Colorado PUC

tristate.coop/benefits-spp-rto-west-participation-highlighted-filing-colorado-puc

06/17/25

- Tri-State requests Colorado Public Utilities Commission finding that SPP RTO is a statutory Organized Wholesale Market and Tri-State's expanded participation in SPP RTO is in the public interest.
- Expanded participation in SPP RTO promotes reliability, affordability and environmental responsibility.

(June 17, 2025, Westminster, Colo.) Following years of collaboration with other regional utilities, transmission providers and stakeholders, Tri-State has filed an application to the Colorado Public Utilities Commission (CoPUC) as the cooperative power supplier plans to expand its participation in the Southwest Power Pool Regional Transmission Organization (SPP RTO) in the West.

Tri-State's application outlines the significant benefits of joining the SPP RTO, under a Federal Energy Regulatory Commission (FERC) approved tariff, as Tri-State and six other Western utilities prepare for full market integration in April 2026. Tri-State's filing marks another milestone in a multi-year effort to expand its market participation to bring increased reliability, affordability, efficiency and responsibility to the region's power grid.

"Grid reliability and resiliency is bolstered with the western expansion of the SPP RTO, as Tri-State serves growing member loads, diversifies our resource portfolio and reduces emissions," said Duane Highley, Tri-State's Chief Executive Officer.

**SPP RTO West to deliver market benefits for Tri-State members**

The SPP RTO provides Tri-State and its members greater access to:

- **Economic benefits**: An estimated $20 million in annual net benefits for Tri-State alone, as part of more than $200 million in potential annual regional benefits.
- **Efficient dispatch**: Optimized use of regional generation and transmission, and more efficient resource integration, including intermittent renewable energy resources.
- **Transmission system optimization:** Coordinated regional use of transmission assets to meet growing energy demand.
- **Environmental performance**: Ability to meet greenhouse gas reduction requirements more cost-effectively, with robust tracking and reporting mechanisms.
- **Improved generator interconnection**: New interconnection procedures and queue reforms to make integrating new resources more efficient.

“The expansion of the SPP RTO is the most cost-effective pathway to organized market benefit for Tri-State’s members,” said Highley. “Our participation will support our members’ goals for reliability, affordability, and a cleaner energy future, with cost savings shared by all members.”

The SPP RTO West would include a cohort of utilities and transmission providers currently participating in the SPP Western Energy Imbalance Service (WEIS) market—including Basin Electric Power Cooperative, Colorado Springs Utilities, Deseret Power Electric Cooperative, the Municipal Energy Agency of Nebraska, Platte River Power Authority, and the Western Area Power Administration (WAPA).

**Significant Tri-State resources, loads to participate, as regional market reduces seams**

FERC approved SPP’s amended tariff in March 2025, enabling SPP to become the first RTO to operate across both the Eastern and Western Interconnections, improving operational flexibility and resiliency across regions.

Tri-State’s owned and contracted resources, transmission and loads in portions of Tri-State’s Colorado, Nebraska and Wyoming Western Interconnection system in the WAPA “WACM” balancing area (BA), which are currently participating in the SPP WEIS market, would transition to the SPP RTO West, including:

- **Resources:** More than 20 generating units, renewable purchase power and contracted resources.
- **Transmission:** More than 3,100 miles of high voltage transmission and more than 200 substations and switching stations.
- **Member Load:** Portions of 23 of Tri-State’s members’ loads, representing 67% percent of gross load across the Tri-State system.

The transition to the SPP RTO West will reduce the number of transmission provider-related seams between transmission providers in Colorado, Wyoming, Montana and Nebraska through the consolidation of seven transmission providers’ tariffs into a SPP RTO common tariff, also reducing the costly “pancaking” of transmission rates. In addition, two BAs will combine to form the SPP West BA. In Colorado, the seam currently between the WACM BA (which becomes part of the SPP West BA) and the Public Service Company of Colorado (Xcel Energy) BA will still exist.

“SPP has successfully shown that it can optimize operations and develop seam agreements between other markets and balancing areas, ” said Highley. “These conversations are already underway for the SPP RTO West.”

**Participation in SPP RTO West years in the making**

Tri-State has played a foundational role in bringing organized markets to the West, working collaboratively with peer utilities and transmission providers to explore and develop organized market participation frameworks tailored to the needs of Western utilities.

“We greatly value the full benefits of the SPP RTO, including day-ahead, real-time and ancillary services markets, efficient regional transmission planning, reliability coordination, a common transmission tariff and a participatory governance model that help us reduce costs and advance clean energy goals,” said Highley.

In 2015, Tri-State became a member of SPP and placed its Eastern Interconnection transmission facilities under SPP’s tariff. In the Western Interconnection, Tri-State was a founding member of SPP’s WEIS market in 2021. Tri-State has participated in the California Independent System Operator’s Western Energy Imbalance Market in a portion of Wyoming since its inception in 2014, expanding participation into New Mexico in 2021.

In 2020, Tri-State first announced its interest in the western expansion of the SPP RTO, with subsequent resource plan filings and stakeholder engagement processes, maintaining transparency concerning Tri-State’s progress in considering its SPP RTO West participation.

“This effort by our staff, SPP, western utilities, and stakeholders, reflects years of collaboration and commitment to shared goals,” said Highley. “We look forward to further demonstrating the benefits of the market to Colorado regulators and stakeholders.”

Tri-State’s filing seeks a CoPUC finding that participation in SPP RTO is in the public interest and SPP RTO meets the Colorado statutory definition of an Organized Wholesale Market. Colorado regulations signed into law in 2021 require transmission utilities, including Tri-State, to join an organized wholesale market by 2030.

**About Tri-State**

Tri-State is a power supply cooperative, operating on a not-for-profit basis, serving electric distribution cooperatives and public power district member-owners in four states. Together with our members, we deliver reliable, affordable and responsible power to more than a million electricity consumers across nearly 200,000 square miles of the rural West. Visit www.tristate.coop.

###

**Contact:**

Lee Boughey, VP Strategic Communications, 720-670-6696, lee.boughey@tristategt.org

Mark Stutz, 303-254-3183, mark.stutz@tristategt.org

Certain information contained in this press statement are forward-looking statements including statements concerning Tri-State's plans, future events, and other information that is not historical information. These forward-looking statements are subject to a number of risks, uncertainties and assumptions, including those described from time to time in Tri-State's filings with the Securities and Exchange Commission. Tri-State's expectations and beliefs are expressed in good faith, and Tri-State believes there is a reasonable basis for them. However, Tri-State cannot assure you that management's expectations and beliefs will be achieved. There are a number of risks, uncertainties and other important factors that could cause actual results to differ materially from the forward-looking statements contained herein.

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Exhibit to
Motion to Intervene and Request for Rehearing and Stay of
Public Interest Organizations

Exhibit 2-65:
CDPHE Regulation No. 3

**DEPARTMENT OF PUBLIC HEALTH AND ENVIRONMENT**

**Air Quality Control Commission**

# REGULATION NUMBER 3 STATIONARY SOURCE PERMITTING AND AIR POLLUTANT EMISSION NOTICE REQUIREMENTS

**5 CCR 1001-5**

*[Editor's Notes follow the text of the rules at the end of this CCR Document.]*

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## Outline of Regulation

PART A Concerning General Provisions Applicable to Reporting and Permitting

PART B Concerning Construction Permits

PART C Concerning Operating Permits

PART D Concerning Major Stationary Source New Source Review and Prevention of Significant Deterioration

PART E Reserved for Environmental Management Systems

PART F Regional Haze Limits - Best Available Retrofit Technology (BART) and Reasonable Progress (RP)

PART G Statements of Basis, Specific Statutory Authority and Purpose

## PART A CONCERNING GENERAL PROVISIONS APPLICABLE TO REPORTING AND PERMITTING

### I. Applicability

I.A. The provisions of this Part A shall apply statewide to all sources of air pollutants except as otherwise provided herein.

All sources of air pollutants that have previously obtained an emissions permit (prior to July 1, 1992) or a construction permit, and are subject only to the Part B Construction Permit Program, may choose to reapply for a new construction permit pursuant to Part B of this Regulation Number 3 in order to obtain the operational flexibility provided in Section IV. of this Part A, or to obtain federally enforceable limitations to limit the source's potential to emit ("synthetic minor"). Sources of air pollutants that are subject only to the Part B Construction Permit Program may voluntarily apply for an Operating Permit pursuant to Part C.

Pursuant to Colorado Revised Statutes Section 24-4-103 (12.5), materials incorporated by reference are available for public inspection during normal business hours, or copies may be obtained at a reasonable cost from the Technical Secretary of the Air Quality Control Commission (the Commission), 4300 Cherry Creek Drive South, Denver, Colorado 80246-1530. The material incorporated by reference is also available through the United States Government Printing Office, online at www.gpo.gov/fdsys. Materials incorporated by reference are those editions in existence as of the date of this regulation as promulgated or revised by the Commission and references do not include later amendments to or editions of the incorporated materials.

I.B. Definitions

I.B.1. Administrative Permit Amendment.

I.B.1.a. A permit revision that:

I.B.1.a.(i) Corrects typographical errors;

I.B.1.a.(ii) Identifies a change in the name, address, or phone number of any person identified in the permit, or provides a similar minor administrative change at the source;

I.B.1.a.(iii) Requires more frequent monitoring or reporting by the permittee;

I.B.1.a.(iv) Allows for a change in ownership or operational control of a source where the Division determines that no other change in the permit is necessary, provided that a written agreement containing a specific date for transfer of permit responsibility, coverage, and liability between the current and new permittee has been submitted to the Division;

I.B.1.b. An administrative permit amendment for purposes of the acid rain portion of a permit shall be governed by regulations promulgated under Title IV of the Federal Act, found at Code of Federal Regulations Title 40, Part 72.

I.B.2. Administrator

The administrator of the U.S. Environmental Protection Agency (U.S. EPA).

I.B.3. Adverse Environmental Effect

As a term used in the context of regulating hazardous air pollutants, any significant and widespread adverse effect, that may reasonably be anticipated, to wildlife, aquatic life, or other natural resources, including adverse impacts on populations of endangered or threatened species or significant degradation of environmental quality over broad areas.

I.B.4. Affected States

All states whose air quality may be affected by issuance of an operating permit, operating permit modification, or operating permit renewal and that are contiguous to Colorado; and/or all states that are within fifty miles of a permitted source.

I.B.5. Affected Unit

A unit that is subject to any acid rain emissions reduction requirement or acid rain emissions limitation pursuant to Title IV of the Federal Act or regulations promulgated there under, in the Code of Federal Regulations Title 40, Part 72.

I.B.6. Air Pollutant

Means carbon monoxide, nitrogen oxides, sulfur dioxide, PM10, PM2.5, total suspended particulates, ozone, volatile organic compounds, lead, all pollutants regulated under Section 111 of the Federal Act (Regulation Number 6), all hazardous air pollutants, and all class I and class II ozone depleting compounds as defined and referenced in Section 602 of the Federal Act.

I.B.7. Allowable Emissions

The emissions rate of a stationary source calculated using the maximum rated capacity of the source (unless the source is subject to federally enforceable or enforceable as a practical matter, permit conditions that restrict the operating rate or hours of operation, or both) and the most stringent of the following:

I.B.7.a. The applicable standards promulgated pursuant to the Federal Act for new source performance or hazardous air pollutants;

I.B.7.b. The applicable Colorado Emission Control Regulation; or

I.B.7.c. The emissions rate specified as a federally enforceable, or enforceable as a practical matter, permit condition, including those with a future compliance date.

I.B.8. Annual Actual Emissions

The actual rate of emissions of a pollutant, excluding excess emissions from a malfunction, or startups and shutdowns associated with a malfunction. Annual actual emissions shall be calculated using the source's actual operating rates, and types of materials processed, stored, or combusted during the calendar year.

I.B.9. Applicable Requirement

Means all of the following as they apply to emissions units in a source subject to operating permit requirements of this regulation (including requirements that have been promulgated or approved by the U.S. EPA through rulemaking at the time of permit issuance but have future effective compliance dates);

I.B.9.a. Any term or condition of any construction permit issued pursuant to Part B of this Regulation Number 3, or any such term or condition as modified by procedures authorized by the operating permit program pursuant to Parts B and C of this Regulation, or any permit issued under Part C or Part D of the Federal Act, except that state-only permit terms or conditions shall remain enforceable solely pursuant to state law;

I.B.9.b. Any standard or other requirement provided for in the state implementation plan;

I.B.9.c. Any standard or other requirement under Section 111 of the Federal Act (New Source Performance Standards), including Section 111(d) of the Federal Act (Standards of Performance for existing sources) (Regulation Number 6);

I.B.9.d. Any standard or other requirement under Section 112 of the Federal Act (hazardous air pollutants, including any requirement concerning accident prevention under Section 112(r)(7) of the Federal Act) (Regulation Number 8) but not including the contents of any risk management plan required under Section 112(r) of the Federal Act;

I.B.9.e. Any requirements for monitoring and compliance assurance monitoring methods and procedures to ensure compliance with permit requirements, including periodic monitoring and testing, and compliance certifications, established pursuant to Sections 504(b) or 114(a)(3) of the Federal Act;

I.B.9.f. Any standards or other requirement under the Code of Federal Regulations Title 40, Part 72 (acid deposition control);

I.B.9.g. Any standard or other requirement governing solid waste incineration;

I.B.9.h. Any standard or other requirement for consumer and commercial products;

I.B.9.i. Any standard or other requirement of the regulations promulgated to protect stratospheric ozone under Title VI of the Federal Act, except where the Administrator has determined such requirement need not be contained in an operating permit (Regulation Number 15);

I.B.9.j. Any national ambient air quality standard or increment or visibility requirement under Part C of Title I of the Federal Act, but only as it would apply to temporary sources permitted pursuant to Part C of this Regulation Number 3.

I.B.10. Carbon Dioxide Equivalent ($CO_2e$)

A metric used to compare the emissions from various GHG classes based upon their global warming potential (GWP). The $CO_2e$ is determined by multiplying the mass amount of emissions (tons per year), for each GHG constituent by that gas's GWP, and summing the resultant values to determine $CO_2e$ (tons per year). The applicable GWPs codified in 40 CFR Part 98, Subpart A, Table A-1 – Global Warming Potentials are hereby incorporated by reference as in effect as of November 29, 2013, but not including later amendments.

I.B.11. Commence, also Commence Construction

When the owner or operator has obtained all necessary pre-construction approvals or permits required by federal, state, or local air pollution and air quality laws and regulations and has either; (a) begun, or caused to begin, a continuous program of physical onsite construction of the source, or (b) entered into binding agreements or contractual obligation that cannot be cancelled or modified without substantial loss to the owner or operator, to undertake a program of actual construction of the source to be completed within a reasonable time. The following activities do not require the owner or operator to obtain a permit: 1) planning; 2) site clearing and grading; 3) ordering of equipment and materials; 4) storing of equipment; 5) setting up temporary trailers to house construction management staff and contractor personnel; 6) engineering and design; and 7) geotechnical investigation. In the event that the source does not qualify for issuance of a permit, the owner or operator accepts the financial risk of commencing these activities.

I.B.12. Commencement of Operation

A new source commences operation when it first conducts the activity that it was designed and permitted for (i.e., producing cement or generating electricity).

I.B.13. Construction Permit

Means the same as an emission permit as required under Part B of this regulation as it existed prior to July 1, 1992, and is the permit required under Colorado Revised Statutes Section 25-7-114.2 after July 1, 1992.

I.B.14. Continuous Emissions Monitoring System (CEMS)

All of the equipment that is required to meet the data acquisition and availability requirements of Part D of this Regulation or of a permit issued in accordance with Parts B or C of this regulation, to sample, condition (if applicable), analyze, and provide a record of emissions on a continuous basis.

I.B.15. Continuous Emissions Rate Monitoring Systems (CERMS)

The total equipment required for the determination and recording of the pollutant mass emissions rate (in terms of mass per unit of time).

I.B.16. Continuous Parameter Monitoring System (CPMS)

All of the equipment necessary to meet the data acquisition and availability requirements of Part D of this Regulation, to monitor process and control device operational parameters (for example, control device secondary voltages and electric currents) and other information (for example, gas flow rate, O2 or CO2 concentrations), and to record average operational parameter value(s) on a continuous basis.

I.B.17. Criteria pollutants

Those pollutants for which the U.S. EPA has established national ambient air quality standards, including: carbon monoxide, nitrogen dioxide (direct emissions and as a precursor to ozone and PM2.5), sulfur dioxide (direct emissions and as a precursor to PM2.5), PM10, PM2.5, total suspended particulate matter, ozone, volatile organic compounds (as a precursor to ozone), and lead.

For the purposes of Air Pollutant Emission Notice reporting, criteria pollutants shall also include nitrogen oxides, fluorides, sulfuric acid mist, hydrogen sulfide, total reduced sulfur, reduced sulfur compounds, municipal waste combustor organics, municipal waste combustor metals, and municipal waste combustor acid gases.

I.B.18. Designated Representative

Means a responsible natural person authorized by the owners and operators of an affected source and of all affected units at the source, as evidenced by a certificate of representation submitted in accordance with Subpart B of Code of Federal Regulations, Title 40, Part 72, to represent and legally bind each owner and operator, as a matter of law, in matters pertaining to the acid rain program. Whenever the term responsible official is used, it shall be deemed to refer to the designated representative with regard to all matters under the acid rain program.

I.B.19. Draft Permit

Means a proposed form of a permit that is released to the public for an opportunity for public comment and hearing, and for affected state review prior to the Division's final decision on a permit application.

I.B.20. Existing Source

An air pollutant source that has been constructed, is in operation, or has received an initial approval of a construction permit prior to the effective date of applicable requirements.

I.B.21. Fugitive Dust

For purposes of this Regulation Number 3, fugitive dust means soil or other airborne particulate matter (excluding particulates produced directly during combustion) resulting from natural forces or from surface use or disturbance, including, but not limited to, all dust from agriculture, construction, forestry, unpaved roads, mining, exploration, or similar activities in which earth is either moved, stored, transported, or redistributed; except that fugitive dust shall not include any fraction of such soil or other airborne particulate matter that is of a size or substance to adversely affect public health or welfare.

I.B.22. General Permit

Means a single permit issued to cover numerous similar sources.

I.B.23. Greenhouse Gas (GHG)

Means the aggregate group of the following six greenhouse gases: carbon dioxide ($CO_2$), nitrous oxide ($N_2O$), methane ($CH_4$), hydrofluorocarbons (HFCs), perfluorocarbons (PFCs), and sulfur hexafluoride ($SF_6$). These gases are treated in aggregate based on the total carbon dioxide equivalent ($CO_2e$) as the pollutant GHG. See definition for carbon dioxide equivalent ($CO_2e$).

For purposes of a GHG PAL, these gases shall not be subject to regulation if the stationary source maintains its total source-wide emissions below the GHG PAL level, meets the requirements of Part D, Section XV., and complies with the PAL permit containing the GHG PAL.

I.B.24. Indirect Source

A facility, building, structure, or installation, or any combination thereof, excluding dwellings, which can reasonably be expected to cause or induce substantial mobile source activity that results in emissions of air pollutants that might reasonably be expected to interfere with the attainment and maintenance of National Ambient Air Quality Standards.

I.B.25. Major Source

Any stationary source or group of stationary sources belonging to the same industrial grouping (see Section I.B.43. of this Part A), that are located on one or more contiguous or adjacent properties and are under common control of the same person (or persons under common control) that:

I.B.25.a. Directly emits, or has the potential to emit considering enforceable controls, in the aggregate, ten tons per year or more of any hazardous air pollutant or twenty-five tons per year or more of any combination of hazardous air pollutants, or such lesser quantity of hazardous air pollutants as may be established pursuant to the Federal Act. Emissions from any oil or gas exploration or production well (with its associated equipment) and emissions from any pipeline compressor or pump station shall not be aggregated with emissions from other similar units, whether or not such units are in a contiguous area or under common control, to determine whether such units or stations are major sources, and in the case of any oil or gas exploration or production well (with its associated equipment), such emissions shall not be aggregated for any purpose under this provision. Fugitive emissions shall be considered in determining whether a stationary source of hazardous air pollutants is a major source.

I.B.25.b. Directly emits, or has the potential to emit, one hundred tons per year or more of any pollutant subject to regulation. Fugitive emissions shall not be considered in determining whether a source is a major source for purposes of this Section I.B.25.b., unless the source belongs to one of the following categories of stationary sources:

I.B.25.b.(i) Coal cleaning plants (with thermal dryers);

I.B.25.b.(ii) Kraft pulp mills;

I.B.25.b.(iii) Portland cement plants;

I.B.25.b.(iv) Primary zinc smelters;

I.B.25.b.(v) Iron and steel mills;

I.B.25.b.(vi) Primary aluminum ore reduction plants;

I.B.25.b.(vii) Primary copper smelters;

I.B.25.b.(viii) Municipal incinerators capable of charging more than 250 tons of refuse per day;

I.B.25.b.(ix) Hydrofluoric, sulfuric, or nitric acid plants;

I.B.25.b.(x) Petroleum refineries;

I.B.25.b.(xi) Lime plants;

I.B.25.b.(xii) Phosphate rock processing plants;

I.B.25.b.(xiii) Coke oven batteries;

I.B.25.b.(xiv) Sulfur recovery plants;

I.B.25.b.(xv) Carbon black plants (furnace process);

I.B.25.b.(xvi) Primary lead smelters;

I.B.25.b.(xvii) Fuel conversion plants;

I.B.25.b.(xviii) Sintering plants;

I.B.25.b.(xix) Secondary metal production plants;

I.B.25.b.(xx) Chemical process plants;

I.B.25.b.(xxi) Fossil-fuel boilers (or combination thereof) totaling more than 250 million British thermal units per hour heat input;

I.B.25.b.(xxii) Petroleum storage and transfer units with a total storage capacity exceeding 300,000 barrels;

I.B.25.b.(xxiii) Taconite ore processing plants;

I.B.25.b.(xxiv) Glass fiber processing plants;

I.B.25.b.(xxv) Charcoal production plants;

I.B.25.b.(xxvi) Fossil fuel-fired steam electric plants of more than 250 million British thermal units per hour heat input; or

I.B.25.b.(xxvii) Any other stationary source categories regulated by a standard promulgated as of August 7, 1980 under Section 111 or 112 of the Federal Act, but only with respect to those air pollutants that have been regulated for that category.

I.B.25.c. Meets any of the definitions of major stationary source set forth in Section II.A.25. of Part D of this Regulation Number 3.

I.B.26. Minor Source

Any stationary source that does not qualify as a major source (as defined in Section I.B.25. above).

I.B.27. Mobile Source

Motor vehicles and other sources of air pollution that emit pollutants while moving and that commonly do not remain at one site (one or more contiguous or adjacent properties owned or operated by the same person or by persons under common control), but does not include portable sources.

I.B.28. Modification

Any physical change in, or change in the method of operation of, a stationary source that does not meet the definition of major modification (as defined in Section II.A.23. of Part D of this regulation), and that increases the emission rate of any pollutant for which a federal or state emission standard has been promulgated or that results in the emission of any such pollutant previously not emitted. The following exceptions apply:

I.B.28.a. Routine maintenance, repair, and replacement shall not be considered a physical change;

I.B.28.b. Unless previously limited by enforceable permit terms and conditions, the following shall not be considered to be a change in the method of operation:

I.B.28.b.(i) An increase in the production rate if such increase does not exceed the design capacity of the source and does not lead to emissions in excess of the emission standards;

I.B.28.b.(ii) An increase in the hours of operation that does not lead to emissions in excess of the emission standards.

I.B.28.b.(iii) Use of an alternative fuel or raw material by reason of an order in effect under Sections 2(a) and (b) of the Federal Energy Supply and Environmental Coordination Act of 1974 (or any superseding legislation), a prohibition under the Federal Power Plan and Industrial Fuel Act of 1978 (or any superseding legislation) or by reason of a natural gas curtailment plan in effect pursuant to the Federal Power Act;

I.B.28.b.(iv) Use of an alternative fuel by reason of an order or rule under Section 125 of the Federal Act; or

I.B.28.b.(v) Change in ownership of the source.

I.B.28.c. Emissions resulting from construction and exploration shall be excluded in determining whether a modification will occur. Emissions from ongoing construction, and emissions from natural gas flaring are not considered to be temporary emissions, and are included in determining whether a modification will occur.

I.B.28.d. This definition shall not be used as a definition of major modification or minor permit modification (as defined in Section I.A.2. of Part C of this regulation)-- these are distinct and separate definitions.

I.B.28.e. Any physical change or change in the method of operation at a source with an operating permit issued pursuant to Part C of this Regulation Number 3, that does not constitute a major modification (as defined in Part D, Section II.A.23. of this Regulation Number 3) and that does not trigger new source performance standards or hazardous air pollutant requirements under the Federal Act is not considered to be a modification; except that any such change shall trigger the provisions of Part B, Section III.D.1.a. through III.D.1.g., and Part C, Sections X.A., and Part C Sections XII.A. or XII.B., as appropriate.

for Administrative Permit Amendment see Section I.B.1. of Part A
for Minor Permit Modification, see Section I.A.2. of Part C
for Major Modification, see Section II.A.23. of Part D

for Permit Modification, see Section I.A.3. of Part C
for Permit Revision, see Section I.B.34. of Part A
for Significant Permit Modification, see Section I.A.7. of Part C

I.B.29. New Source

A stationary air pollution source, other than an existing source; or any source that resumes operation after being inactive for more than one year after having been shut down for the purpose of eliminating emissions that violated any applicable emission control regulation or regulation for the control of hazardous air pollutants.

I.B.30. Non-criteria Reportable Pollutants

The list of pollutants set forth in Appendix B and those ozone-depleting compounds listed in Section 602 of the Federal Act.

I.B.31. Non-Road Engine

I.B.31.a. Except as discussed in Section I.B.31.b. of this definition, a non-road engine is an internal combustion engine:

I.B.31.a.(i) In or on a piece of equipment that is self-propelled or serves a dual purpose by both propelling itself and performing another function (such as garden tractors, off-highway mobile cranes and bulldozers); or

I.B.31.a.(ii) In or on a piece of equipment that is intended to be propelled while performing its function (such as lawnmowers and string trimmers); or

I.B.31.a.(iii) That, by itself or in or on a piece of equipment is portable or transportable, meaning designed to be and capable of being carried or moved from one location to another. Indicia of transportability include, but are not limited to wheels, skids, carrying handles, dolly, trailer or platform.

I.B.31.b. An internal combustion engine is not a non-road engine if:

I.B.31.b.(i) The engine is used to propel a motor vehicle or a vehicle used solely for competition, or is subject to standards promulgated under Section 202 of the Federal Act; or

I.B.31.b.(ii) The engine is regulated by a federal New Source Performance Standard promulgated under Section 111 of the Federal Act; or

I.B.31.b.(iii) The engine otherwise included in Section I.B.31.a.(iii) of this definition remains or will remain at a location for more than twelve consecutive months or a shorter period of time for an engine located as a seasonal source. A location is any single site at a building, structure, facility, or installation. Any engine (or engines) that replaces an engine at a location and that is intended to perform the same or similar function as the engine replaced will be included in calculating the consecutive time period. An engine located at a seasonal source is an engine that remains at a seasonal source during the full annual operating period of the seasonal source. A seasonal source is a stationary source that remains in a single location on a permanent basis (i.e., at least two years) and that operates at a single location approximately three months (or more) each year. This Section does not apply to an engine after the engine is removed from the location.

I.B.31.c. (State-only Requirements) Non-road engines not co-located at an existing major source

An operator of a non-road engine as defined in Section I.B.31.a.(iii), above, with a manufacturer's site-rated horsepower of 1,200 or greater, or an aggregation of such non-road engines each with a manufacturer's site-rated horsepower of 1,200 or greater, that operate more than 4,380 hours per year at the same location are subject to the following state-only requirements:

I.B.31.c.(i) Submit an air pollutant emission notice and pay the appropriate fees pursuant to Section VI. of Part A of this regulation;

I.B.31.c.(ii) Submit an application for a site-specific, temporary, non-road engine permit on forms supplied by the Division if the estimated annual actual emissions reported on the Air Pollutant Emission Notice, as required by Section I.B.31.c.(i), are equal to or exceed one hundred tons per year or more of nitrogen oxides, 100 tons per year or more of carbon monoxide, or forty tons per year or more of sulfur dioxide. After receipt and review of a complete application, the Division shall issue a state-only non-road engine permit containing such terms and conditions as are necessary to protect the ambient air quality standards.

I.B.31.c.(iii) The operator of a non-road engine that is exempt based on hours of operation or the annual emissions thresholds described above, must maintain sufficient records to verify that the engine or engines are exempt from the state-only reporting and permit requirements. Such records shall be made available for Division review upon request.

I.B.31.d. (State-only Requirements) Non-road engines co-located at an existing major source of nitrogen oxides or sulfur dioxide

An operator of a non-road engine or aggregation of engines each with a manufacturer's site-rated horsepower of 1,200 or greater, and are non-road engines under Section I.B.31.a.(iii) of this definition, are subject to the following state-only requirements:

I.B.31.d.(i) Submit an air pollutant emission notice and pay the fees required by Section VI. of this Part;

I.B.31.d.(ii) Submit an application for a site-specific, temporary, state-only non-road engine permit on forms supplied by the Division if the estimated annual actual emissions reported on the air pollutant emission notice, as required by Section I.B.29.d.(i), are equal to or exceed forty tons per year or more of nitrogen oxides, one hundred tons per year or more of carbon monoxide, or forty tons per year or more of sulfur dioxide. After receipt and review of a complete application, the Division shall issue a temporary state-only non-road engine permit containing such terms and conditions as are necessary to protect the ambient air quality standards.

I.B.31.d.(iii) The operator of a non-road engine that is 1,200 horsepower or greater, but is exempt on the basis of the annual emissions thresholds described above, must maintain sufficient records to verify that the engine or engines are exempt from the state-only reporting and permit requirements. Such records shall be made available for Division review upon request.

I.B.32. Operating Permit

Unless the context suggests otherwise, any permit or group of permits covering an operating permit source that is issued, renewed, amended or revised pursuant to Part C of this Regulation Number 3.

I.B.33. Operating Permit Source

Any source subject to the permitting requirements of Part C of this regulation.

I.B.34. Permit Revision

Any permit modification, minor permit modification, or administrative permit amendment. No permit revision shall be required for increases in emissions that are authorized by allowances acquired pursuant to the acid rain program provided that such increases do not require a permit revision under any other applicable requirement.

I.B.35. Pollution Prevention

Any activity that through process changes, product reformulation or redesign, or substitution of less polluting raw materials, eliminates or reduces the release of air pollutants (including fugitive emissions) and other pollutants to the environment prior to recycling, treatment, or disposal. This definition does not include recycling (other than certain “in-process recycling” practices), energy recovery, treatment, or disposal.

I.B.36. Portable Source

A source such as, but not limited to, asphalt batch plants and aggregate crushers that commonly and by usual practice is moved from one site to another. A source will not be considered portable if it remains on one site for more than two years.

I.B.37. Potential to Emit

The maximum capacity of a stationary source to emit a pollutant under its physical and operational design. Any physical or operational limitation on the capacity of the source to emit a pollutant, including air pollution control equipment and restrictions on hours of operation or on the type or amount of material combusted, stored, or processed, shall be treated as part of its design if the limitation or the effect it would have on emissions is state enforceable and federally enforceable. Secondary emissions do not count in determining the potential to emit of a stationary source.

I.B.38. Predictive Emissions Monitoring System (PEMS)

All of the equipment necessary to monitor process and control device operational parameters (for example, control device secondary voltages and electric currents) and other information (for example, gas flow rate, O2 or CO2 concentrations), and calculate and record the mass emissions rate (for example, lb/hr) on a continuous basis.

I.B.39. Regulated Air Pollutant

Nitrogen oxides or any volatile organic compounds, except as listed in the definition of negligibly reactive volatile organic compounds in the Common Provisions regulation; any pollutant for which a national or state ambient air quality standard has been promulgated; any pollutant that is subject to any standard promulgated under Section 111 of the Federal Act (Regulation Number 6); any class I or II substance subject to a standard promulgated under or established by Title VI of the Federal Act; any pollutant subject to a standard promulgated under Section 112 or other requirements established under Section 112 of the Federal Act, including Sections 112(g), (j), and (r) of the Federal Act; and any pollutant subject to a standard promulgated pursuant to Colorado Revised Statutes Section 25-7-109.3(5)(a), (state-only hazardous air pollutants listed in Section 25-7-109.3(5)(a) are subject to state enforcement only and do not trigger enforcement by the Administrator or by citizens under Section 304 of the Federal Act.)

Once a source becomes subject to the operating permit requirements, regulated air pollutants must be addressed in the permit application and in the permit.

I.B.40. Responsible Official

One of the following:

I.B.40.a. For a corporation: a president, secretary, treasurer, or vice president of the corporation in charge of a principal business function, or any other person who performs similar policy or decision making functions for the corporation, or a duly authorized representative of such person if the representative is responsible for the overall operation of one or more manufacturing, production, or operating facilities applying for or subject to a permit and either:

I.B.40.a.(i) The facilities employ more than two hundred and fifty persons or have gross annual sales or expenditures exceeding twenty-five million dollars (in second quarter 1980 dollars); or

I.B.40.a.(ii) The delegation of authority to such representative is approved in advance by the Division;

I.B.40.b. For a partnership or sole proprietorship: a general partner or the proprietor, respectively;

I.B.40.c. For a municipality, state, federal, or other public agency; either a principal executive officer, or ranking elected official. For the purposes of this section, a principal executive officer of a federal agency includes the chief executive officer having responsibility for the overall operations of a principal geographic unit of the agency; or

I.B.40.d. For affected sources:

I.B.40.d.(i) The designated representative in so far as actions, standards, requirements, or prohibitions under Title IV of the Federal Act or the regulations, found at Code of Federal Regulations Title 40, Part 72, promulgated there under are concerned; and

I.B.40.d.(ii) The designated representative under Title IV of the Federal Act or the Code of Federal Regulations Title 40, Part 72 for any other purposes under the Code of Federal Regulations Title 40, Part 70.

I.B.41. Schedule of compliance

A schedule of required measures, including an enforceable sequence of actions or operations, leading to compliance with an applicable state implementation plan, emission standard, emission limitation, emission prohibition, or emission control regulation.

I.B.42. State-only Condition

Means any standard, term or condition that is not required by Part C of this regulation (Title V Operating Permits), Part D of this regulation (major New Source Review), Title III (hazardous air pollutants) or Section 111 (New Source Performance Standards) of the Federal Act, is not required to be federally enforceable to participate in the early reductions program, is not required to create a federally enforceable emissions limitation in order to create a synthetic minor source (as defined in Section I.A. of this Part), or is otherwise more stringent than a requirement under the Federal Act.

I.B.43. Stationary Source

Any building, structure, facility, or installation, or any combination thereof belonging to the same industrial grouping that emits or may emit any air pollutant subject to regulation under the Federal Act, that is located on one or more contiguous or adjacent properties and that is owned or operated by the same person or by persons under common control. Those emissions resulting directly from an internal combustion engine for transportation purposes or from a non-road engine as defined in Section I.B.29. of this Part shall not be considered a stationary source. Building, structures, facilities, equipment, and installations shall be considered to belong to the same industrial grouping if they belong to the same major groups (i.e., have the same two-digit codes) as described in the Standard Industrial Classification Manual, 1987, but not later amendments. See National Technical Information Service, Order Number PB 87-100012. The manual is available for examination at the office of the Director of the Air Pollution Control Division, Department of Public Health and Environment, 4300 Cherry Creek Drive South, Denver, Colorado 80246-1530.

for Affected Source see Section I.A.1. of Part C
for Existing Source, see Section I.B.20. of Part A
for Indirect Source, see Section I.B.24. of Part A
for Major Source, see Section I.B.25. of Part A
for Major Stationary Source, see Section II.A.25. of Part D

for Minor Source, see Section I.B.26. of Part A
for Mobile Source, see Section I.B.27. of Part A
for New Source, see Section I.B.29. of Part A
for Portable Source, see Section I.B.36. of Part A
for Temporary Source, see Section I.B.45. of Part A

I.B.44. Subject to Regulation

For any air pollutant, that the pollutant is subject to either a provision in the Federal Act, or a nationally-applicable regulation codified by the Administrator in Subchapter C of 40 CFR Chapter I of the Federal Act, that requires actual control of the quantity of emissions of the pollutant, and that such a control requirement has taken effect and is operative to control, limit or restrict the quantity of emissions of that pollutant released from the regulated activity, except that:

I.B.44.a. GHG shall not be subject to regulation except as provided in Sections I.B.44.d. through f. of this Part A.

I.B.44.b. For purposes of Section I.B.44.c. through e., the term CO2e of this Part A, shall represent an amount of GHG emitted, and shall be computed as follows:

I.B.44.b.(i) Multiplying the mass amount of emissions (tpy), for each of the six GHGs in the pollutant GHG, by the gas's associated GWP published at Table A-1 to Subpart A of Part 98 of 40 CFR as in effect November 29, 2013, which is hereby incorporated by reference, but not including later amendments. For purposes of this paragraph, prior to July 21, 2014, the mass of the greenhouse gas carbon dioxide shall not include carbon dioxide emissions resulting from the combustion or decomposition of non-fossilized and biodegradable organic material originating from plants, animals, or micro-organisms (including products, by-products, residues and waste from agriculture, forestry and related industries as well as the non-fossilized and biodegradable organic fractions of industrial and municipal wastes, including gases and liquids recovered from the decomposition of non-fossilized and biodegradable organic material).

I.B.44.b.(ii) Sum the resultant value from Section I.B.44.b.(i) of this Part A, for each gas to compute a tpy CO2e.

I.B.44.c. The term emissions increase as used in Sections I.B.44.d. through e. of this Part A, shall mean that both a significant emissions increase (as calculated using the procedures in Section II.A.23 of Part D) and a significant net emissions increase (as defined in Sections II.A.26, and II.A.44 of Part D) occur. For the pollutant GHG, an emissions increase shall be based on tpy CO2e, and shall be calculated assuming the pollutant GHG is a regulated NSR pollutant, and significant is defined as 75,000 tpy CO2e instead of applying the value in Section II.A.44.b. of Part D.

I.B.44.d. Beginning January 2, 2011, the pollutant GHG is subject to regulation concerning major stationary source new source review and prevention of significant deterioration if:

I.B.44.d.(i) The stationary source is a new major stationary source for a regulated NSR pollutant that is not GHG, and also will emit or will have the potential to emit 75,000 tpy CO2e or more; or

I.B.44.d.(ii) The stationary source is an existing major stationary source for a regulated NSR pollutant that is not GHG, and also will have an emissions increase of a regulated NSR pollutant, and an emissions increase of 75,000 tpy CO2e or more.

I.B.44.e. Repealed.

I.B.44.f. If there is a change in federal law that supersedes, or the District of Columbia Circuit Court of Appeals or the United States Supreme Court directs or issues an order, which limits or renders ineffective the regulation of GHG emissions at stationary sources under the New Source Review Prevention of Significant Deterioration(PSD) or Title V provisions of the Federal Act the regulation, GHG emissions under the corresponding programs in this Regulation Number 3 shall be limited or rendered ineffective to the same extent.

I.B.45. Temporary Source

A source in operation for not more than two years in duration unless the Division determines that a longer time period is appropriate.

I.B.46. Uncontrolled Actual Emissions

The annual emission rate corresponding to the annual process rate listed on the Air Pollutant Emission Notice form, without consideration of any emission control equipment or procedures.

The Division may allow a source to forego calculating or estimating its uncontrolled actual emissions of hazardous air pollutants upon a showing by the source and a determination by the Division that the creation of such data is unreasonably costly, technically impractical or not reasonably related to information necessary for making regulatory decisions with respect to that source. The Division's final determination may be appealed to the Commission by the source.

I.B.47. Wet Screening Operations

A screening operation at a nonmetallic mineral processing plant that removes unwanted material or that separates marketable fines from the product by a washing process that is designed and operated at all times such that water is an integral part of the process and the product is saturated with water. Screens that use spray bars for the purposes of dust control are not included in this definition.

## II. Air Pollutant Emission Notice (APEN) Requirements

II.A. Air Pollutant Emission Notices for New, Modified, and Existing Sources

Except as specifically exempted in Section II.D., no person shall allow emission of air pollutants from, or construction, modification or alteration of, any facility, process, or activity which constitutes a stationary source, except residential structures, from which air pollutants are, or are to be, emitted unless and until an Air Pollutant Emission Notice and the associated Air Pollutant Emission Notice fee has been filed with the Division with respect to such emission. Each such notice shall specify the location at which the proposed emission will occur, the name and address of the persons operating and owning such facility, the nature of such facility, process or activity, an estimate of the quantity and composition of the expected emission and other information as required in the current Air Pollutant Emission Notice form.

II.B. General

II.B.1. Emission Estimate

The Air Pollutant Emission Notice shall include an estimate of the annual actual emissions, including emission controls. The emissions estimate shall be based upon actual test data or, in the absence of such data, upon estimations acceptable to the Division. The following alternative estimate methods, in order of descending acceptability, are acceptable to the Division:

II.B.1.a. Mass balance calculations or a published, verifiable emission factor, whichever is best applied to the source; or

II.B.1.b. Other engineering calculations.

Stack testing or emission monitoring will not be required solely to meet the Air Pollutant Emission Notice reporting requirements.

An owner or operator shall provide a justification to the Division for not using any methods that are higher on the list than the method the owner or operator proposes to use. If none of the above methods are available or applicable to the source, an appropriate method will be determined on a case-by-case basis by the Division, taking into account the provisions of Section II.C.2. of this Part A.

The Division shall make available to all air pollution control authority offices appropriate forms on which the information required by this section shall be submitted.

II.B.2. Air Pollutant Emission Notice Term

An Air Pollutant Emission Notice is valid for a period of five years. The five-year period recommences when a revised Air Pollutant Emission Notice is received by the Division.

II.B.3. APEN Applicability

For the purposes of Air Pollutant Emission Notice applicability, a source will be considered to be an individual emission point, or group of points pursuant to Section II.B.4. of this Part A.

II.B.3.a. Criteria Pollutants

For criteria pollutants, Air Pollutant Emission Notices are required for: each individual emission point in a nonattainment area with uncontrolled actual emissions of one ton per year or more of any individual criteria pollutant (pollutants are not summed) for which the area is nonattainment; each individual emission point in an attainment or attainment/maintenance area with uncontrolled actual emissions of two tons per year or more of any individual criteria pollutant (pollutants are not summed); each individual emission point with uncontrolled actual emissions of lead greater than one hundred pounds per year, regardless of where the source is located.

II.B.3.b. Non-criteria Reportable Pollutants

For non criteria reportable pollutants, Air Pollutant Emission Notices are required for each individual emission point with uncontrolled actual emissions equal to or greater than 250 pounds per year or more of any individual non-criteria reportable pollutant (pollutants are not summed).

II.B.4. Source Grouping

Grouping of multiple emission points on a single Air Pollutant Emission Notice shall be allowed as often as possible, provided the overall goals of receiving accurate and verifiable emissions information are not compromised. The following guidelines shall be used to delineate occasions when grouping can be allowed. These are intended to be used as guidelines only, and specific questions regarding grouping should be directed to the Division.

Multiple pieces of equipment or processes from a single facility may be grouped or associated together and reported on one single Air Pollutant Emission Notice provided the individual sources of emissions meet the following guidelines:

II.B.4.a. All of the aggregated sources have identical source classification codes and emission factors for criteria pollutants;

II.B.4.b. Each of the aggregated sources share a similar location within the facility;

II.B.4.c. Similar sources regulated under the New Source Performance Standards (Regulation Number 6) and non-New Source Performance Standard sources should not be grouped;

II.B.4.d. None of the individual sources is required to monitor emissions through the use of continuous emission monitors;

II.B.4.e. Each of the individual emission points has fuel usage, production, and a consumption level, which are indistinguishable from the other points, which have been grouped on the Air Pollutant Emission Notice;

II.B.4.f. None of the individual sources grouped on the Air Pollutant Emission Notice has previously been issued its own separate emissions permit.

The Division maintains its authority to require individual separate Air Pollutant Emission Notices for any process or activity.

The Division may allow a source to deviate from this emission point grouping criteria upon a showing that an alternative is reasonable and will not compromise the overall goals of receiving accurate and verifiable emissions information.

II.B.5. Air Pollutant Emission Notices and revised Air Pollutant Emission Notices shall be based on calendar years (January through December).

II.B.6. The emissions noted on the current Air Pollutant Emission Notice on file with the Division shall be used for emission fee calculations as described in Section VI. of this Part A.

II.C. Revised Air Pollutant Emission Notices

II.C.1. A revised Air Pollutant Emission Notice shall be filed:

II.C.1.a. Annually whenever a significant change (as defined in Section II.C.2.) in annual actual emissions occurs; or

II.C.1.b. Whenever there is a change in the owner or operator of any facility, process, or activity; or

II.C.1.c. Whenever new control equipment is installed, or whenever a different type of control equipment replaces an existing type of control equipment (revised Air Pollutant Emission Notices are not required for routine maintenance, repair, or replacement of control equipment; or

II.C.1.d. Whenever a permit limitation must be modified; or

II.C.1.e. Before the Air Pollutant Emission Notice expires.

II.C.1.f. A revised Air Pollutant Emission Notice is not required whenever the location of a portable facility, process, or activity is changed, however, the owner or operator of such source must file a relocation notice. Such notice shall be received by the Division at least ten days prior to the change in location. Alternatively, the owner or operator of a portable source may request written approval from the Division to report multiple relocations. Relocation forms are available at the Division offices.

II.C.1.g. A revised Air Pollutant Emission Notice is not required for emergency or backup generators that are ancillary to the main units at electric utility facilities, and that have a permit under Parts C or D of Title I, or Title V of the Federal Act.

II.C.1.h. A revised Air Pollutant Emission Notice is not required for emergency or backup generators for electric power generating facilities that are not ancillary to a main unit at an electric utility facility, and that have a permit containing limits on the physical or operational capacity of the source to emit a pollutant such that the source is not considered to be a major stationary source as defined in Section II.A.25. of Part D of this Regulation Number 3. If an owner or operator of such a source chooses to file a revised Air Pollutant Emission Notice, the Air Pollutant Emission Notice shall list the average of the annual actual emissions for the preceding three years.

II.C.2. Significant change, for the purposes of this section means:

II.C.2.a. For any non-criteria reportable pollutant if the emissions increase by fifty percent or five tons per year, whichever is less, above the level reported on the last Air Pollutant Emission Notice submitted to the Division.

II.C.2.b. For criteria pollutants:

II.C.2.b.(i) For sources emitting less than one hundred tons per year, a change in annual actual emissions, of the individual criteria pollutant less than one hundred tons per year, of five tons per year or more, above the level reported on the last Air Pollutant Emission Notice submitted to the Division; or

II.C.2.b.(ii) For volatile organic compound and nitrogen oxides sources in ozone nonattainment areas emitting less than one hundred tons of volatile organic compound and nitrogen oxides per year, a change in annual actual volatile organic compound or nitrogen oxide emissions of one ton per year or more or five percent, whichever is greater, above the level reported on the last Air Pollutant Emission Notice submitted to the Division; or

II.C.2.b.(iii) For sources emitting one hundred tons per year or more, a change in annual actual emissions, of the criteria pollutant above one hundred tons per year, of five percent or fifty tons per year or more, whichever is less, above the level reported on the last Air Pollutant Emission Notice submitted to the Division; or

II.C.2.b.(iv) A change in annual actual emissions, above the level reported on the last Air Pollutant Emission Notice submitted to the Division, of fifty pounds of lead.

II.C.3. Timeframe for Revised Air Pollutant Emission Notice submittals

II.C.3.a. Revised Air Pollutant Emission Notices shall be submitted no later than within thirty days before the five-year term expires.

II.C.3.b. Owners or operators of sources that are required to obtain a permit revision must file a revised Air Pollutant Emission Notice along with a request for permit revision. A revised permit must be obtained before the change at the source occurs.

II.C.3.c. Sources submitting revised Air Pollutant Emission Notices to inform the Division of a change in annual actual emission rates must do so by April 30 of the following year (e.g., a change in emissions in calendar year 1993 must be reported by April 30, 1994).

II.C.3.d. Air Pollutant Emission Notices for changes in control equipment must be submitted before the change occurs); except for control equipment at condensate storage tanks located at oil and gas exploration and production facilities subject to the requirements in Regulation Number 7, Section XII. For this control equipment, a revised APEN shall be filed once per year, as specified in Section II.C.3.c. of Part A, if any control equipment is added or if control equipment is relocated or removed.

II.C.4. Emissions reported

II.C.4.a. Sources submitting revised Air Pollutant Emission Notices due to Sections II.C.1.a., II.C.1.b., or II.C.1.e. must report actual annual emissions. Actual annual emissions for sources utilizing emission control equipment or procedures represent controlled actual annual emissions.

II.C.4.b. Sources submitting revised Air Pollutant Emission Notices due to Sections II.C.1.c. or II.C.1.d. must report both uncontrolled actual annual emissions and controlled actual emissions.

II.D. Exemptions from Air Pollutant Emission Notice Requirements

II.D.1. Stationary sources having emission units that are exempt from the requirement to file an Air Pollutant Emission Notice must nevertheless comply with all requirements that are otherwise applicable specifically to the exempted emission units, including, but not limited to: Title V, Prevention of Significant Deterioration, nonattainment New Source Review, opacity limitations, odor limitations, particulate matter limitations and volatile organic compounds controls.

An applicant may not omit any information regarding APEN exempt emission units in any permit application if such information is needed to determine the applicability of Title V (Part C of this Regulation Number 3), Prevention of Significant Deterioration (Section VI., Part D of this Regulation Number 3), or nonattainment New Source Review (Section V., Part D of this Regulation Number 3).

The following sources are exempt from the requirement to file Air Pollutant Emission Notices because by themselves, or cumulatively as a category, they are deemed to have a negligible impact on air quality.

II.D.1.a. Individual emission points in nonattainment areas having uncontrolled actual emissions of any criteria pollutant of less than one ton per year, and individual emission points in attainment or attainment/maintenance areas having uncontrolled actual emissions of any criteria pollutant of less than two tons per year, and each individual emission point with uncontrolled actual emissions of lead less than one hundred pounds per year, regardless of where the source is located.

II.D.1.b. Individual emission points having uncontrolled actual emissions of any individual non-criteria reportable pollutant less than 250 pounds per year.

II.D.1.c. Air conditioning or ventilating systems not designed to remove air pollutants generated by or released from other processes or equipment.

II.D.1.d. Fireplaces used for recreational purposes, inside or outside.

II.D.1.e. Fires and equipment used for noncommercial cooking of food for human consumption, or cooking of food for human consumption at commercial food service establishments, except for char broilers and wood fired equipment (but not including campfires) in PM10 nonattainment areas. Charbroiler shall mean a cooking device in a commercial food service establishment, either gas fired or using charcoal or other fuel, upon which grease drips down upon an open flame, charcoal or embers.

II.D.1.f. Safety flares used to indicate danger to the public.

II.D.1.g. Agricultural operations such as farming, cultivating, harvesting, seasonal crop drying, grain handling operations that are below New Source Performance Standards de minimis levels (including milling and grain elevator operations), and animal feeding operations that are not housed commercial swine feeding facilities as defined in Regulation Number 2, Part B. This exemption does not apply to an agricultural operation that: (1) is a major source (as defined in Section I.B.25. of this part); (2) meets or exceeds the storage capacity thresholds of a federal New Source Performance Standard (Regulation Number 6, Part A); or (3) participates in the early reduction program of the Federal Act, Section 112. Ancillary operations such as fueling stations located at farms or ranches are not exempt from Air Pollutant Emission Notice and permit requirements unless otherwise below the de minimis emission levels contained in this regulation, and are not exempt from other applicable regulation promulgated by the Commission.

II.D.1.h. Emissions from, or construction, or alteration of residential structures, including all buildings or other structures used primarily as a place of residence, and including home heating devices.

II.D.1.i. Laboratories and research & development facilities:

II.D.1.i.(i) Noncommercial (in house) experimental and analytical laboratory equipment that is bench scale in nature including quality control/quality assurance laboratories, process support laboratories, environmental laboratories supporting a manufacturing or industrial facility, and research and development laboratories.

II.D.1.i.(ii) Research and development activities that are of a small pilot scale and that process less than ten thousand pounds of test material per year;

II.D.1.i.(iii) Small pilot scale research and development projects less than six months in duration with controlled actual emissions less than five hundred pounds of any criteria pollutant or ten pounds of any non criteria reportable pollutant.

II.D.1.j. Disturbance of surface areas for purposes of land development, that do not exceed twenty-five contiguous acres and that do not exceed six months in duration. (This does not include mining operations or disturbance of contaminated soil).

II.D.1.k. Each individual piece of fuel burning equipment, other than smokehouse generators and internal combustion engines, that uses gaseous fuel, and that has a design rate less than or equal to five million British thermal units per hour. (See definition of fuel burning equipment, Common Provisions Regulation).

II.D.1.l. Internal combustion engines powering portable drilling rigs.

II.D.1.m. Exemption Repealed

II.D.1.n. Chemical storage tanks or containers that hold less than five hundred gallons, and that have an annual average daily throughput of less than twenty-five gallons.

II.D.1.o. Unpaved public and private roadways, except for haul roads located within a stationary source site boundary.

II.D.1.p. Sanding of streets and roads to abate traffic hazards caused by ice and snow.

II.D.1.q. Open burning activities, except that all reporting and permitting requirements that apply to such operations must be followed (see Regulation Number 9).

II.D.1.r. Brazing, soldering, or welding operations, except those that use lead based compounds. All welding that occurs strictly for maintenance purposes is exempt.

II.D.1.s. Street and parking lot striping.

II.D.1.t. Battery recharging areas.

II.D.1.u. Aerosol can usage.

II.D.1.v. Sawing operations, that is ancillary to facility operations, and is not part of the production process.

II.D.1.w. The process of demolition and re bricking of furnaces and kilns. This does not include subsequent operation of such furnaces or kilns.

II.D.1.x. Road and lot paving operations at commercial and industrial facilities, except that asphalt and cement batch plants require Air Pollutant Emission Notices and permits, unless exempt under some other section.

II.D.1.y. Adhesive use that is not related to production.

II.D.1.z. Fire training activities.

II.D.1.aa. Caulking operations that are not part of a production process.

II.D.1.bb. Landscaping and site housekeeping devices equal to or less than ten horsepower in size (lawnmowers, trimmers, snow blowers, etc.).

II.D.1.cc. Fugitive emissions from landscaping activities (e.g., weeding, sweeping).

II.D.1.dd. Landscaping use of pesticides, fumigants, and herbicides.

II.D.1.ee. Exemption Repealed

II.D.1.ff. Emergency events such as accidental fires.

II.D.1.gg. Smoking rooms and areas.

II.D.1.hh. Plastic pipe welding.

II.D.1.ii. Vacuum cleaning systems used exclusively for industrial, commercial, or residential housekeeping purposes.

II.D.1.jj. Beauty salons.

II.D.1.kk. Operations involving acetylene, butane, propane and other flame cutting torches.

II.D.1.ll. Pharmacies.

II.D.1.mm. Chemical storage areas where chemicals are stored in closed containers, and where total storage capacity does not exceed five thousand gallons. This exemption applies solely to storage of such chemicals. This exemption does not apply to transfer of chemicals from, to, or between such containers.

II.D.1.nn. Architectural painting, roof coating material and associated surface preparation (except for sandblasting and except for volatile organic compound emissions, associated with surface preparation, above Air Pollutant Emission Notice de minimis levels) for maintenance purposes at industrial or commercial facilities.

II.D.1.oo. Emissions that are not criteria (as defined in Section I.B.17. of this part) or non-criteria reportable pollutants (as defined in Section I.B.30. of this part) (These emissions include methane, ethane, and carbon dioxide).

II.D.1.pp. Janitorial activities and products.

II.D.1.qq. Grounds keeping activities and products.

II.D.1.rr. Sources of odorous emissions that do not utilize emission control equipment for control of odorous emissions. This exemption applies to the odor emissions only. All other emissions are subject to other exemptions set forth in this regulation. This exemption does not exempt any source from the requirements of Regulation Number 2.

II.D.1.ss. Truck and car wash units.

II.D.1.tt. Office emissions, including cleaning, copying, and restrooms.

II.D.1.uu. Exemption Repealed

II.D.1.vv. Electrically operated curing ovens, drying ovens and similar activities, articles, equipment, or appurtenances. This exemption applies to the ovens only, and not to the items being dried in the ovens.

II.D.1.ww. Equipment used exclusively for portable steam cleaning.

II.D.1.xx. Blast cleaning equipment using a suspension of abrasive in water and any exhaust system or collector serving them exclusively.

II.D.1.yy. Commercial laundries (except dry cleaners) that do not burn liquid or solid fuel.

II.D.1.zz. Storage of butane, propane, or liquefied petroleum gas in a vessel with a capacity of less than sixty thousand gallons, provided the requirements of Regulation Number 7, Section IV. are met, where applicable.

II.D.1.aaa. Storage tanks of capacity less than forty thousand gallons of lubricating oils or used lubricating oils.

II.D.1.bbb. Venting of compressed natural gas, butane or propane gas cylinders, with a capacity of one gallon or less.

II.D.1.ccc. Fuel storage and dispensing equipment in ozone attainment areas operated solely for company owned vehicles where the daily fuel throughput is no more than four hundred gallons per day that is calculated as an annual average. Sources in an ozone attainment/maintenance area must utilize Stage 1 vapor recovery on all tanks greater than 550 gallons capacity, as required by Regulation Number 7, in order to take this exemption.

II.D.1.ddd. Exemption Repealed

II.D.1.eee. Indirect sources are exempt until a permit regulation specific to indirect sources is promulgated by the Commission.

II.D.1.fff. Storage tanks meeting all of the following criteria:

II.D.1.fff.(i) Annual throughput is less than four hundred thousand gallons; and

II.D.1.fff.(ii) The liquid stored is one of the following:

II.D.1.fff.(ii)(A) Diesel fuels 1 D, 2 D, or 4 6;

II.D.1.fff.(ii)(B) Fuel oils #1 through #6;

II.D.1.fff.(ii)(C) Gas turbine fuels 1 GT through 4 GT;

II.D.1.fff.(ii)(D) oil/water mixtures with a vapor pressure equal to or lower than that of diesel fuel (Reid Vapor Pressure of 0.025 pounds per square inch absolute).

II.D.1.ggg. Each individual piece of fuel burning equipment that uses gaseous fuel, and that has a design rate less than or equal to ten million British thermal units per hour, and that is used solely for heating buildings for personal comfort.

II.D.1.hhh. Natural gas vehicle fleet fueling facilities.

II.D.1.iii. Electric motors driving equipment at non-commercial machining shops.

II.D.1.jjj. Recreational swimming pools.

II.D.1.kkk. Forklifts.

II.D.1.lll. Oil and gas exploration and production operations (well site and associated equipment) shall provide written notice to the Colorado Oil and Gas Conservation Commission of proposed drilling locations prior to commencement of such operations. Air Pollutant Emission Notices are not required until after exploration and/or production drilling, workovers, completions, and testing are finished.

If production will result in reportable emissions, the owner or operator shall file an Air Pollutant Emission Notice with the Division within thirty days after the well completion or recompletion report and log is filed with the appropriate state or federal agency. If production will not occur, or production will not result in reportable emissions, the owner or operator shall submit written notice to the Division indicating that the well was plugged, or that emissions are otherwise not reportable. If production will result in reportable emissions, the owner or operator shall file an Air Pollutant Emission Notice with the Division within thirty days after the report of first production is filed with the appropriate state or federal agency but no later than ninety days following the first day of production.

II.D.1.mmm. Handling equipment and associated activities for glass that is destined for recycling.

II.D.1.nnn. Fugitive emissions of hazardous air pollutants that are natural constituents of native soils and rock (not added or concentrated by chemical or mechanical processes) from underground mines or surface mines unless such source is a major source of hazardous air pollutants under Part C of Regulation Number 3.

II.D.1.ooo. The use of pesticides, fumigants, and herbicides when used in accordance with requirements established under the federal Insecticide, Fungicide and Rodenticide Act as established by the U.S. EPA (United States Code Title 7, Section 136 et seq.).

II.D.1.ppp. Ventilation of emissions from mobile sources operating within a tunnel, garage, or building that are not operating for transportation purposes and are subject to stationary source requirements.

II.D.1.qqq. Non-asbestos demolition.

II.D.1.rrr. Sandblast equipment when the blast media is recycled and the blasted material is collected, including small sandblast glove booths.

II.D.1.sss. Exemption Repealed

II.D.1.ttt. Exemption Repealed

II.D.1.uuu. Surface water storage impoundment of non-potable water and storm water evaporation ponds, with the exceptions of oil and gas production wastewater impoundments (including produced water tanks) containing equal to or more than one percent by volume crude oil on an annual average and commercial facilities that accept oil and gas production wastewater for processing.

II.D.1.vvv. Non-potable water pipeline vents.

II.D.1.www. Steam vents and safety release valves.

II.D.1.xxx. Exemption Repealed

II.D.1.yyy. Seal and lubricating oil systems for steam turbine electric generators.

II.D.1.zzz. Venting of natural gas lines for safety purposes.

II.D.1.aaaa. Chemical Storage Tanks

II.D.1.aaaa.(i) Sulfuric acid storage tanks not to exceed ten thousand five hundred gallons capacity.

II.D.1.aaaa.(ii) Sodium hydroxide storage tanks.

II.D.1.bbbb. Containers, reservoirs, or tanks used exclusively for dipping operations that contain no organic solvents for coating objects with oils, waxes, greases, or natural or synthetic resins.

II.D.1.cccc. Wet screening operations notwithstanding the applicability of the New Source Performance Standards included in the Code of Federal Regulations, Title 40, Part 60, Subpart OOO.

II.D.1.dddd. Non-road engines as defined in Section I.B.31. of this Part A, except certain non-road engines subject to state-only air pollutant emission notice and permitting requirements pursuant to Section I.B.31.c. and I.B.31.d. of this part.

II.D.1.eeee. Exemption Repealed

II.D.1.ffff. Exemption Repealed

II.D.2. An Air Pollutant Emission Notice must be filed for all incinerators.

II.D.3. Air Pollutant Emission Notices are required for emergency and backup generators that are ancillary to the main units at electric utility facilities however, these units may be included on the same Air Pollutant Emission Notice as the main unit.

II.D.4. Any person may request the Division to examine a particular source category or activity for exemption from Air Pollutant Emission Notice or permit requirements.

II.D.4.a. Such requests shall be made separately from the permit application review procedure.

II.D.4.b. Such requests shall include documentation indicating that emissions from the source category or activity have a negligible impact on air quality and public health in Colorado, based on, but not limited to, the following criteria.

II.D.4.b.(i) Emissions from the source or activity are below the Air Pollutant Emission Notice or permit emission de minimis levels set forth in this Regulation Number 3; or

II.D.4.b.(ii) The existing Division emission inventory is sufficient to indicate that the source or activity has a negligible impact; or

II.D.4.b.(iii) For permit exemptions, criteria in Sections II.D.4.b.(i) and/or II.D.4.b.(ii), above, are met, and the source or activity has no applicable requirement that applies to it, and the Division finds that monitoring or record keeping are not necessary.

II.D.4.b.(iv) Exemptions shall not be granted for any source or activity that is subject to any federal applicable requirement. The Division shall determine on a case-by-case basis if sources or activities subject to state only regulations may be granted an exemption.

II.D.4.c. None of the activities submitted as exemption requests to the Division may be taken by a source until the Commission has duly adopted the exemptions as revisions to this Regulation Number 3 and the U.S. EPA has approved the exemption requests.

II.D.5. Commercial (for hire) laboratories whose primary responsibilities are to perform qualitative or quantitative analysis on environmental, clinical, geological, forensic, or process samples may estimate emissions for purposes of Air Pollutant Emission Notice reporting based upon a mass balance calculation utilizing inventory and purchase records of solvents and reagents. Such laboratories may, at their discretion, group emission points if such grouping meets the grouping criteria outlined in this regulation. All inert samples are exempt from Air Pollutant Emission Notice reporting. Emissions from samples subjected to analysis provided to such laboratories for analysis and testing, and by-products that result from sample testing, are exempt from Air Pollutant Emission Notice reporting, provided such samples subjected to analysis are less than five gallons for liquids, or five pounds for solids.

II.D.6. Research and development activities that do not fall within the small scale exemption in Section II.D.1.i. may estimate emissions for purposes of Air Pollutant Emission Notice reporting based upon either a mass balance calculation utilizing inventory and purchase records, or best engineering judgment. Such facilities may file an Air Pollutant Emission Notice or revised Air Pollutant Emission Notice on an annual basis by April 30 of the year following the project's conclusion for each project that is not exempt under Section II.D.1.i., irrespective of Section II.C., herein (revised Air Pollutant Emission Notice requirements), such Air Pollutant Emission Notices shall be filed on a per project basis and shall be based on controlled actual emissions.

## III. Administrative Permit Amendment Procedures

III.A. An application for an administrative permit amendment shall be prepared on forms supplied by the Division.

III.B. Within sixty calendar days after receipt of a complete application for an administrative permit amendment the Division shall issue its final determination on such application in accordance with the following:

III.B.1. Deny the application for an administrative permit amendment; or

III.B.2. Grant the application and incorporate any such changes into the permit providing such permit revisions are made pursuant to this Part A, Section III.

III.C. A source may implement the changes addressed in the application for an administrative amendment immediately upon submittal of request, subject to the final determination of the Division.

III.D. As required under the Federal Act, the Division shall transmit to the Administrator a copy of each revised permit made pursuant to an administrative permit amendment under this provision.

III.E. No public notice or review by affected states shall be necessary for permit revisions made pursuant to administrative amendment procedures.

III.F. Administrative permit amendments for purposes of the acid rain portion of a permit shall be governed by regulations promulgated under Title IV of the Federal Act, found at Code of Federal Regulations Title 40, Part 72.

**IV. Operational Flexibility**

IV.A. Alternative operating scenarios

No permit revision is required for reasonably anticipated operating scenarios identified by the source in its application for a permit and approved by the Division, provided the permit contains terms and conditions that:

IV.A.1. Require the source, contemporaneously with making a change from one operating scenario to another, to record in a log at the permitted facility a record of the scenario under which it is operating;

IV.A.2. Ensure that the terms and conditions of each such alternative scenario meet all applicable requirements of the state and Federal Act.

IV.A.3. Extend the permit shield to all operating permit terms and conditions under each such operating scenario.

IV.B. Trading based on the permit

If allowed by the applicable state implementation plan, no permit revision shall be required under any approved economic incentives, marketable permits, emissions trading and other similar programs or processes for changes in emissions that are provided for in the permit. The permit applicant must request such provisions to be included in its permit, and if approved by the Division, the permit shall contain terms and conditions that:

IV.B.1. For operating permits, include all terms required under Section V.C. of Part C;

IV.B.2. Ensure that changes resulting from such increases and decreases in emissions meet all applicable requirements under the state and Federal Acts;

IV.B.3. Extend the permit shield to all operating permit terms and conditions that allow such increases and decreases in emissions.

IV.C. Emissions trading under permit caps

No permit revision shall be required where an applicant requests, and the Division approves such request, for a permit containing terms and conditions allowing for the trading of emissions increases and decreases in the permitted facility. Procedures for such changes are:

IV.C.1. For operating permits, the permit shall contain terms and conditions required pursuant to Section V.C. of Part C;

IV.C.2. The permit applicant shall include in its application proposed replicable procedures and permit terms that ensure the emissions trades are quantifiable;

IV.C.3. Any emissions units for which emissions are not quantifiable or for which there are no replicable procedures to enforce the emissions trades shall not be included in this provision allowing emissions trading without permit revision;

IV.C.4. The source shall comply with all other applicable requirements.

IV.C.5. The source shall provide a minimum of seven days written notification in advance of the proposed changes to the Division and to the Administrator. The notice must be received by the Division no later than seven days in advance of the proposed changes. The source and the Division shall attach each such notice to their copy of the relevant permit. The notice shall contain:

IV.C.5.a. When the change will occur;

IV.C.5.b. A description of the changes in emissions that will result and how these increases and decreases in emissions will comply with the terms and conditions of the permit;

IV.C.5.c. The permit shield shall extend to all operating permit terms and conditions that allow such increases and decreases in emissions.

IV.C.6. A source shall be allowed to make such change proposed in its notice on the day following the last day of the advance notice described in Section IV.C.5. above, if the Division has not responded nor objected to such changes on or before that day.

## V. Certification And Trading Of Emission Reduction Credits Offset And Netting Transactions

V.A. Purpose

This section establishes procedures for the recording of certified emissions reductions and for their use in emission credit transactions. These procedures are intended to:

V.A.1. Promote economic development and lower the cost of meeting pollution control requirements while assuring ambient air quality progress and continued air quality maintenance; and

V.A.2. Encourage development of innovative pollution control methods and technologies.

V.B. Scope

This section applies to any pollutant regulated under the Colorado Air Quality Control Act or the regulations promulgated there under in all attainment, attainment/maintenance, and nonattainment areas of the state. This section does not apply to emissions trading under permit caps in Section IV.C. of Part A.

V.C. Definitions

V.C.1. Alternative compliance methods means the use of emissions reductions credits to meet emissions control requirements in lieu of an applicable control technique guidance method or reasonably available control technology.

V.C.2. Bubble lets existing sources (or groups of sources) increase emissions at one operation in exchange for compensating extra decreases in emissions at another operation. The net result must be equivalent to or better than would have been accomplished using conventional source specific controls.

V.C.3. Certified emissions reduction means a reduction in emissions below the baseline that has been certified by the Division in accordance with the criteria of Section V.E., and that may then be used in an emission credit transaction.

V.C.4. Criteria pollutant means an air pollutant for which a National Ambient Air Quality Standard has been promulgated.

V.C.5. Emission credit transaction means the use of certified emission reduction credits in a bubble, netting or offset transaction or as an alternative compliance method.

V.C.6. Major stationary source means major stationary source as defined in Section II.A.25. of Part D of this regulation.

V.C.7. Net emissions increase means net emissions increase as defined in Section II.A.27. of Part D of this regulation.

V.C.8. Netting is designed to exempt modifications of existing major stationary sources from new source review requirements if the resultant impact does not exceed any of the significant values found in the definition of significant in Section II.A.44. of Part D of this regulation.

V.C.9. Non-inventoried source means any source that has not been recorded on the Division's emission inventory system.

V.C.10. Offset means a transaction in which a certified emissions reduction is used either to avoid causing a violation of an increment in an attainment or attainment/maintenance area, to meet the requirements of Section V.A.3. of Part D of this regulation, regarding the maintenance of reasonable further progress towards attainment of the National Ambient Air Quality Standards in nonattainment areas, or to avoid contributing to visibility or other air quality related values impairment in a Class I area.

V.C.11. Registry means the Division's record of the certification and use of emissions reductions.

V.C.12. Significant means significant as defined in Section II.A.44. of Part D of this regulation.

V.C.13. Surplus means emission reductions not required by current regulations, relied on for state implementation plan planning purposes, and not used to meet any other regulatory requirement.

V.C.14. Open Dust means solid or other air borne particulate matter (excluding particulates produced directly during combustion) resulting from natural forces or from surface use or disturbance, including, but not limited to, all dust from agriculture, construction, forestry, unpaved roads, mining, exploration, or similar activities in which earth is either moved, stored, transported or redistributed.

V.C.15. Baseline emissions are equal to the product of the:

V.C.15.a. Emission Rate (ER), specified in terms of mass emission per unit of production or throughput (e.g., pounds sulfur dioxide per million British thermal units or pounds of volatile organic compounds per weight of solids applied);

V.C.15.b. Average hourly capacity utilization (CU) e.g., millions of British thermal units per hour or weight of solids applied per hour; and

V.C.15.c. Number of hours of operation (H) during the relevant time period i.e., baseline emissions = ER x CU x H. Net baseline emissions for a bubble are the sum of the baseline emissions of all sources involved in the trade.

V.D. Procedure for Certification of Emissions Reductions and Approval of Transactions

V.D.1. The owner or operator of a source may request the Division to certify any emissions reduction anticipated to occur after the effective date of this section, provided the owner or operator files his application prior to the occurrence of the reduction, at a time at which the source is emitting the baseline emissions of the subject pollutant. Sources that shutdown prior to the application to bank or trade have zero emissions, and therefore no credit is available.

V.D.2. Upon receiving an application for certification, the Division may require the applicant to submit all data and calculations necessary to verify the baseline emissions or the reduction of emissions below the base level including, but not limited to, documentation of operating hours and inputs. The Division may also require the applicant to perform source tests to establish the baseline emissions or the reduction of emissions below the baseline emissions. The Division shall not certify reductions anticipated to occur after the effective date of this regulation until the reductions have occurred and been verified.

V.D.3. The Division shall maintain an emissions reduction registry, in which it shall maintain a record of all certified emissions reductions, and of the use of certified emissions reductions in emission credit transactions. The information contained in such registry shall include the name and address of the owner or operator of the source creating the emissions reduction, the location of the source, its stack parameters, the temperature and velocity of its plume, particle size, the existence of any hazardous pollutants, daily and seasonal emission rates, and any other data that might reasonably be necessary to evaluate future use.

V.D.4. If the Division determines that certification should be granted it shall modify the permit of the applicant to provide that the allowable emissions are equal to the level of current emissions utilized in the calculation of the emissions reduction. The owner or operator of a source not required to obtain a permit by provisions of law other than this section shall be required to apply for and accept a permit as a condition of obtaining a certified emissions reduction. Such permits shall contain only those conditions necessary to ensure the enforcement of the emissions limitations applicable to the source as a result of certification of its emissions reduction.

V.D.5. The amount of the emissions reduction to be certified and entered in the registry shall be calculated as follows:

V.D.5.a. For any emissions reduction that has occurred in an attainment or attainment/maintenance area, the amount of the certified emissions reduction shall be 90 percent of the amount by which emissions have been reduced below the baseline emissions.

V.D.5.b. For any emissions reduction that has occurred in a nonattainment area, the amount of the certified emission reduction shall be 80 percent of the amount by which emissions have been reduced below the baseline emissions.

V.D.5.c. For bubbles in nonattainment areas that need, but lack, approved demonstrations of attainment, i.e., areas with unapproved state implementation plans, a greater discount may be taken. This discount will be based on the area's total baseline emissions, the target emissions for attainment, the emissions for the projected attainment year and the reductions needed to achieve attainment. These values are dynamic and so the discount value may change from year to year but will never be less than 20 percent. These transactions will require a state implementation plan revision.

V.D.6. An application may be filed for approval of the use of a certified emissions reduction in an emissions credit transaction simultaneously with the filing of a certification application, or within seven years after certification has been granted. If the transaction would require the modification of permits held by more than one person, the application shall be jointly submitted by all potentially affected permittees. The Commission shall determine whether to approve all bubble and alternative compliance method transactions, or any offset transactions that, pursuant to Section V.H., require a state implementation plan revision. The Division shall determine whether to approve all netting transactions, or any offset transactions for which no state implementation plan revision is required. The Commission may approve the use of a certified emissions reduction credit as an alternative compliance method in lieu of a specified control technique guidance method or reasonable available control technology.

V.D.7. Applications for certification of emissions reductions and approval of transactions shall be made on forms provided by the Division. Any source applying for approval of an alternative compliance method transaction shall submit to the Division a construction permit application in accordance with Regulation Number 3, Part B, Section III. for the construction or modification, reflecting the source and proposed use of the emissions credit. The application shall contain information sufficient to demonstrate that the criteria set forth in Section V.F. of this Part A are met as well as the criteria for approval of the state implementation plan revision. The Division shall review the application and prepare its preliminary analysis in accordance with Regulation Number 3, Part B, Section III.B. The source requesting approval for the transaction and the state implementation plan revision should be granted, and shall provide with its petition, a copy of the preliminary analysis of the Division. The Division shall not grant initial approval of any such application until the Commission has approved the transaction, the source has met the conditions placed on the transaction by the Commission, and the requirements of all other applicable regulations are met.

V.D.8. Where the owner or operator of a source requests a state implementation plan revision pursuant to this Section V., the Commission shall set a hearing on the proposed revision to be held in accordance with the procedures set forth in Colorado Revised Statutes Section 25-7-119. With respect to applications for certification of emissions reductions, or for approval of any netting transactions, or offset transactions within the Division's jurisdiction under Section V.H.2., the same time limitations for emission permits as found in Part B Section III.B. of this regulation shall apply.

V.D.9. Applicants for certification of an emissions reduction, or for approval of any emission credit transaction, shall be assessed fees for time spent by Division personnel in evaluating such applications in accord with the criteria for assessment of emissions permit fees set forth in Section VI.C. of this Part A. Where more than one person applies for approval of a transaction, all such persons shall be jointly liable for the fees assessed. Applicants shall be responsible for paying such fees regardless of whether the Division approves or denies an application. The costs of Division review of any emissions modeling or other information necessary for the Division to formulate recommendations to the Commission regarding any proposed emission credit transaction shall be included in the costs attributed to the permit application for the source(s) seeking approval of the transaction and shall be paid by the source regardless of whether the emission credit transaction is approved.

V.D.10. The state shall not utilize a certified emissions reduction in making demonstrations of attainment, or reasonable further progress toward attainment of the National Ambient Air Quality Standards, within seven years after the date of certification, or at any time after an application for use of the certified emissions reduction in a transaction has been approved. Where no application has been filed for the approval of the use of a certified emissions reduction within seven years after certification was granted, the state shall subsequently utilize the reduction in making demonstrations of attainment, or reasonable further progress towards attainment of the National Ambient Air Quality Standards. This seven-year period shall be tolled during any time in that there is a pending application before the Division or the Commission for approval of a bubble, netting, or offset transaction based on the certified emissions reduction.

V.D.11. Applications for approval of transactions involving PM10 (fine particulates for Prevention of Significant Deterioration increment consumption), sulfur dioxide, carbon monoxide, lead, and oxides of nitrogen (where visibility impacts are of concern), shall be subject to the following ambient air quality modeling requirements:

V.D.11.a. De minimis: In general modeling is not required to determine the ambient equivalence of trades in which applicable net baseline emissions do not increase and in that the sum of the emissions increases, looking only at the increasing sources, 15 tons per year for PM10, 40 tons per year for sulfur dioxide, 100 tons per year for carbon monoxide, 40 tons per year for nitrogen oxide (where visibility impacts are of concern), or 0.6 tons per year for lead, after applicable control requirements. For purposes of Prevention of Significant Deterioration any increase in PM10 should be modeled.

V.D.11.b. Level 1: In general, modeling to determine ambient equivalence is not required if:

V.D.11.b.(i) The trade does not result in an increase in applicable net baseline emissions;

V.D.11.b.(ii) The relevant sources are located in the same immediate vicinity (within 250 meters) of each other;

V.D.11.b.(iii) An increase in baseline emissions does not occur at the source with the lower effective plume height, as determined under the U.S. EPA approved and Division accepted guidelines, as interpreted in the Code of Federal Regulations Title 40, Subpart 52.343.

V.D.11.b.(iv) No complex terrain is within the area of significant impact (see Figure 1) of the trade or 50 kilometers, whichever is less;

V.D.11.b.(v) Stacks with increasing baseline emissions are sufficiently tall to avoid possible downwash situations, as determined by good engineering practice;

V.D.11.b.(vi) The trade does not involve open dust sources.

V.D.11.c. Level II: Bubble trades that are neither De minimis nor Level I may nevertheless be evaluated for approval based on modeling to determine ambient equivalence limited solely to the impacts of the specific emission sources involved in the trade, if:

V.D.11.c.(i) There is no increase in applicable net baseline emissions;

V.D.11.c.(ii) If the potential change in emissions before and after the trade will not cause a significant increase in pollutant concentrations at any receptor for an averaging time specified in an applicable ambient air quality standard; and

V.D.11.c.(iii) Such an analysis does not predict any increase in ambient concentrations in a Class I or Category I area. However, a bubble will not be approved under Level II where evidence clearly indicates the bubble would create a new violation of an ambient standard or Prevention of Significant Deterioration increment or would delay the planned removal of an existing violation. The change in concentration from the before-trade case to the after-trade case must, in general, be modeled using refined models for each appropriate averaging time for the relevant national ambient air quality standards for each receptor, using the most recent full year of meteorological data. Other techniques may be approved where sources show they equally well protect national ambient air quality standards, applicable Prevention of Significant Deterioration increments, and visibility. For example, in limited circumstances conservative screening models may be acceptable in lieu of refined models. In such cases, use of a full year of meteorological data may not be necessary. Such screening models may be acceptable where: (A) the screening model shows that all the emissions from the stack(s) with increasing emissions would not produce exceedances of the Level II significance values; (B) the stack parameters at the stack(s) with increasing emissions do not change; and (C) the screening model shows that the increase in emissions at the increasing stack(s) would not produce exceedances of these significant values.

In determining significant impact for Level II bubble trades, the Division will use the following significance values to identify trades whose potential ambient impact need not be further evaluated before approval:

8-micrograms/cubic meter (µg/m3) for any twenty-four hour period for PM10;

4-micrograms/cubic meter (µg/m3) for any annual arithmetic mean for PM10;

13-micrograms/cubic meter (µg/m3) for any twenty-four hour period for sulfur dioxide;

46-micrograms/cubic meter (µg/m3) for any three-hour period for sulfur dioxide;

3-micrograms/cubic meter (µg/m3) for any annual period for sulfur dioxide;

575-micrograms/cubic meter (µg/m3) for any eight-hour period for carbon monoxide;

2,300-micrograms/cubic meter (µg/m3) for any one-hour period for carbon monoxide;

0.1 micrograms/cubic meter (µg/m3) for any three-month period for lead. Except that:

V.D.11.c.(iii)(A) For offset transactions, significant impact shall be determined by the values found in the table of significant values in Section VI.D.2. of Part D of this regulation.

V.D.11.c.(iii)(B) Only process fugitive emissions vented through stacks may be approved in a Level II analysis.

V.D.11.c.(iii)(C) Trades involving open dust sources may not be approved in a Level II analysis.

V.D.11.c.(iii)(D) Trades involving complex terrain cannot be approved with a Level II analysis.

V.D.11.d. LEVEL III full dispersion modeling considering all sources affecting the trade's area of impact is required to determine ambient equivalence if applicable net baseline emissions will increase as a result of the trade, or if the trade cannot meet criteria for approval under De Minimis, Level I or Level II.

V.D.11.e. Approved Models:

Modeling: Only U.S. EPA-approved models may be used in banking transactions. Use of non-guideline models will be allowed once they have been approved according to the requirements of Section VIII.A.1. of Part A of this regulation.

V.D.12. Following the certification of an emissions reduction, if the Division determines that certification was granted on the basis of fraud or material misstatement or omission, the Division shall revoke certification of the reduction. Certification shall be revoked only after the owners or operators of the affected sources have received notice and, if requested, a hearing has been conducted. In such cases the Division shall also modify the permit of the source that has used the emissions reduction, so that the permit will contain all conditions that would have applied if the emissions reduction had not been certified initially.

V.E. Criteria for Certification of Emissions Reductions

An emissions reduction shall be certified for use in an emission credit transaction, provided it meets the following criteria:

V.E.1. The emissions reduction shall be surplus. Surplus reductions are those below the baseline emissions. The baseline emissions shall be determined as follows:

V.E.1.a. In attainment and attainment/maintenance areas, the baseline emissions shall be a source's actual emissions of the subject pollutant, or allowable emissions whichever is lower, for the three baseline factors. Reasonably Available Control Technology shall be as set forth in the State implementation plan for the source. Where Reasonably Available Control Technology has not been determined in the state implementation plan for the source, it shall be determined by the Division.

V.E.1.b. In nonattainment areas for which there is a demonstration of attainment of the National Ambient Air Quality Standards approved by the U.S. EPA the baseline emissions shall be actual emissions, provided, however, the baseline emissions shall not exceed reasonably available control technology as defined in the state implementation plan or the level of emissions used by the state in making a demonstration of attainment.

V.E.1.c. In nonattainment areas for which there is not a demonstration of attainment of National Ambient Air Quality Standards approved by the U.S. EPA, the baseline emissions shall be the lower of: 1) the actual emissions, 2) allowable emissions under the state implementation plan or 3) allowable emissions if the source is subject to Reasonably Available Control Technology.

V.E.1.d. Emission rate, capacity utilization and hours of operation must be used to compute pre-trade and post-trade emission levels. Baseline must be established on an annual basis and for all other averaging periods consistent with the relevant National Ambient Air Quality Standards and Prevention of Significant Deterioration increments.

V.E.2. No emissions reduction shall be certified if the Division has relied upon the occurrence of the reduction in demonstrating attainment of the National Ambient Air Quality Standards or reasonable further progress towards attainment, or in establishing a baseline concentration.

V.E.3. Each certified reduction of a pollutant's emissions shall be quantified in the same unit of measurement used in the standard or regulation applicable to the pollutant.

V.E.4. In attainment and attainment/maintenance areas, reductions at major stationary sources that commenced construction after January 1, 1975 may be able to qualify for credit whether such reductions occurred before or after the Prevention of Significant Deterioration baseline triggering date. Other emission reductions (e.g., at minor sources) cannot qualify for credit where the Prevention of Significant Deterioration baseline date is or has been triggered and such reductions occurred prior to the trigger date, unless these reductions are not assumed in the Prevention of Significant Deterioration baselines. Since banked emission reduction credits must be considered to be “In the Air” for all planning purposes, if the baseline date is triggered before banked credits are actually used, such banked credits will be considered as part of the baseline and will not consume increment when used in an emissions trade.

In attainment and attainment/maintenance areas where the Prevention of Significant Deterioration baseline has not been triggered as of the date the permitting authority takes relevant final action on the trading transaction, reductions below current state implementation plan or permit limits generally may be used without special restrictions in bubble or banking transactions, provided they are otherwise creditable and there is assurance that National Ambient Air Quality Standards will not be violated due to any potential increase in actual emissions. However, reductions at sources other than major stationary sources on which construction commenced before January 1, 1975 may not be used to balance increases at such pre 1975 major sources.

V.E.5. Emission reductions achieved by shutting down an existing source or curtailing production or operating hours below baseline levels may be generally credited if such reductions are permanent, quantifiable, and federally enforceable, and if the area has an U.S. EPA-approved attainment plan. In addition, the shutdown or curtailment is creditable only if it occurred on or after the date specified for this purpose in the plan, and if such date is on or after the date of the most recent emissions inventory used in the plan's demonstration of attainment. Where the plan does not specify a cutoff date for shutdown credits, the date of the most recent emissions inventory or attainment demonstration, as the case may be, shall apply. However, in no event may credit be given for shutdowns that occurred prior to August 7, 1977. For purposes of this section a permitting authority may choose to consider a prior shutdown or curtailment to have occurred after the date of its most recent emissions inventory, if the inventory explicitly includes as current existing emissions the emissions from such previously shutdown or curtailed sources.

V.E.5.a. Such reductions may be credited in the absence of an approved attainment demonstration only if the shutdown or curtailment occurred on or after the date the new source permit application is filed, or, if the applicant can establish that the proposed new source is a replacement for the shutdown or curtailed source, and the cutoff date provisions of Section A, above, are met.

V.E.6. No emission reduction credits are allowed from mobile sources unless those sources are subject to ambient impact and new source review permitting.

V.E.7. Reductions down to compliance levels may not qualify for emission reduction credit.

V.E.8. If an existing source commits to switch to a cleaner fuel at some future date, emission reduction credit is allowable only if a permit is conditioned to require use of a specified alternative control measure that would achieve the same degree of emission reduction should the source switch back to a dirtier fuel at some later date. The Division will ensure that adequate long-term supplies of the new fuel are available before granting the reduction credit.

V.E.9. Emission reductions otherwise required by the Federal Act shall not be creditable as emission reductions. Incidental emission reductions that are not otherwise required by the Federal Act are creditable as emission reductions if such emission reductions meet the requirements of Section V. of Part D of this regulation, if applicable and this Section V.

V.E.10. The total tonnage of increased emissions, in tons per year, resulting from a major modification that must be offset in accordance with Section 173 of the Federal Act shall be determined by summing the difference between the allowable emissions (as defined in Section I.B.7. of this part) after the modification and the actual emissions (as defined in Section II.A.1. of Part D) before the modification for each emissions unit.

V.F. Criteria for Approval of all Transactions

The use of an emissions reduction in an emission credit transaction shall be approved only if it meets the following criteria:

V.F.1. The transaction shall involve like pollutants. For toxic or volatile organic compound pollutants, the trade should involve the same degrees of toxicity or photochemical reactivity or else a greater reduction may be required. New or modified major sources of a PM10 precursor can only obtain offsets from emissions reductions in that same PM10 precursor or in PM10. New or modified major sources of PM10 can only obtain offsets from emissions reductions in PM10. The offsets must be greater than one for one and represent a net air quality benefit in the area the source is proposing to locate or modify. (See exception in Section V.H.8.)

V.F.2. No transaction shall be approved if it will result in an increased concentration, at the point of maximum impact, of hazardous air pollutants.

V.F.3. Where a significant fraction of a criteria pollutant stream has been listed as hazardous by the Commission under Regulation Number 8 or the U.S. EPA under United States Code, Title 42, Section 7412 but has not yet been regulated, emissions containing that pollutant from sources within two hundred and fifty meters of each other may only be traded against each other on a greater than one for one basis that assures a net decrease in emissions of the hazardous pollutant.

V.F.4. Hazardous and non-hazardous emissions of the same criteria pollutant may be traded against each other, provided the total emissions containing the hazardous pollutant from the sources involved in the transaction are required to decrease as a result of the transaction.

V.F.5. No transaction may be approved that is inconsistent with any standard established by the Federal Act, the state Act or the regulations promulgated under either, or to circumvent New Source Performance Standards requirements or Best Available Control Technology although the Commission may approve a transaction using a certified emissions reduction credit in lieu of a specified control technique guidance method or reasonably available control technology.

V.F.6. No transaction shall be approved unless either:

V.F.6.a. The source at which the emissions reduction occurred and the source using the emissions reductions are in the same nonattainment area or Prevention of Significant Deterioration baseline area; or

V.F.6.b. The emissions reduction is to be used as an offset to meet the requirements of Section V.A.3. of Part D of this regulation, and the conditions of that section are met for the use of an offset obtained from a source outside the nonattainment area.

V.F.7. Emission reduction credits may not be used to meet applicable technology based requirements for new sources such as New Source Performance Standards, Best Available Control Technology, or Lowest Achievable Emission Rate, although the Commission may approve a transaction using a certified emissions reduction credit in lieu of a specified control technique guidance method or reasonably available control technology.

V.F.8. Trades Involving Open Dust: Sources of particulate emissions may be approved through case by case state implementation plan revisions based on modeled demonstrations of ambient equivalence. Sources proposing such trades must commit, as part of the trade's approval, to:

V.F.8.a. Undertake a post approval monitoring program to evaluate the impact of their control efforts, and

V.F.8.b. Make further enforceable reductions if post trade monitoring indicates initial open dust controls do not produce the predicted air quality results.

V.F.9. The federal land manager must be notified if an emissions trade will take place within one hundred kilometers of a Prevention of Significant Deterioration Class I area. Notification must occur early enough in the review process to allow at least thirty days for the submittal of comments before the trade will be approved by the reviewing authority.

Where a bubble within fifty kilometers of a Prevention of Significant Deterioration Class I area is submitted as a case-by-case state implementation plan revision, the Division may call for additional technical support, beyond the applicable requirements of the modeling screen if deemed necessary to protect air quality in the Class I area.

V.F.10. Effect on Trades of Subsequently-Discovered Clean Air Act Problems: Revisitation Considerations - If ambient violations are discovered in an area where the Division has approved a trade, or if other violations of the act are discovered in that area, sources in the trade should be aware that they are potentially subject to requirements for additional emission reductions, just as are all other sources in the area.

V.F.11. For volatile organic compound and nitrogen oxide trades, pound for pound trades will be considered equal in ambient effect where all sources involved in the trade are in the same control strategy demonstration area (nonattainment area) or if outside that area are sufficiently close to show an equal effect.

V.F.12. For volatile organic compound trades involving surface coating, the emissions must be calculated on a solids applied basis and should specify the maximum time period over which the emissions may be averaged, not to exceed twenty-four hours.

V.F.13. The following trades require a state implementation plan revision:

V.F.13.a. PM10, sulfur dioxide, carbon monoxide or lead trades requiring full-scale dispersion modeling under Level III;

V.F.13.b. PM10, sulfur dioxide, carbon monoxide or lead trades where complex terrain is within the area of the source's significant impact or fifty kilometers, whichever is less, unless the trade does not result in a modification of effective stack heights and the trade otherwise qualifies as De minimis or Level I. The area of significant impact can be determined from Figure 1;

V.F.13.c. Open Dust Trades;

V.F.13.d. Level II trades involving process fugitive PM10, sulfur dioxide , carbon monoxide or lead emissions not discharged through stacks;

V.F.13.e. Trades involving Emission Reduction Credits from mobile sources (see Section V.E.7.);

V.F.13.f. Trades involving sources that are subject of a notice of violation (NOV), noncompliance penalty action or the filing of a judicial complaint;

V.F.13.g. Interstate trades;

V.F.13.h. Volatile organic compound trades with averaging times longer than twenty-four hours;

V.F.13.i. Trades involving work practice and equipment standards;

V.F.13.j. Trades involving negotiated Reasonably Available Control Technology baselines;

V.F.13.k. Trades affecting areas that need but lack approved demonstrations of attainment.

V.F.13.l. Emission credit transactions used as an alternative compliance method.

V.F.14. No emission credit transaction shall be approved unless the terms of the transaction are incorporated in permits applicable to the originating (as applicable) and receiving emissions sources.

V.F.15. Emission credit transactions that require a state implementation plan revision shall be considered by the Commission on a case-by-case basis. The source requesting approval of the transaction has the burden of demonstrating that all the criteria of this Section V.F., are met and of demonstrating that all applicable requirements for approval of the state implementation plan revision has been met.

V.G. Bubble Transactions

V.G.1. An owner or operator of an existing source may apply to the Commission for approval of a state implementation plan revision establishing a bubble. The bubble shall establish new emissions limitations for two or more facilities or operations within the source.

V.G.2. The Commission shall not approve a bubble unless it meets the criteria for approval of Section V.F., and the Division has first certified an emissions reduction at a facility or operation included in the bubble.

V.G.3. As part of the certification process, the amount of allowable emissions shall be reduced at the facility or operation where the emissions reduction has occurred in accord with Section V.D.5. As part of the bubble approval, the Commission may approve an increase in the total allowable emissions at the other facilities or operations covered by the bubble, by an amount not to exceed the amount of the subject certified emissions reduction.

V.G.4. As part of the bubble approval, the Commission may extend compliance deadlines otherwise required by Commission regulations for volatile organic compounds or carbon monoxide emissions, provided the following criteria are met:

V.G.4.a. The applicant must demonstrate to the satisfaction of the Commission that reasonable further progress toward the attainment of the National Ambient Air Quality Standards under the state implementation plan shall be maintained either by:

V.G.4.a.(i) Achievement of emissions reductions earlier than otherwise required by certain facilities or operations covered by the bubble; or

V.G.4.a.(ii) Temporary use of a certified emissions reduction to assure reasonable further progress toward attainment of the National Ambient Air Quality Standards.

V.G.5. If subsequent to the approval of a bubble, the Commission promulgates new regulations or amends existing regulations applicable to a source for which the bubble has been approved, the source shall be required to meet the new or amended regulations, irrespective of the bubble, by either further reducing emissions or using certified emissions reductions as offsets.

V.G.6. Bubble applications in areas that require but lack approved demonstrations of attainment, i.e., non approved state implementation plans, must be accompanied by assurances of consistency with ambient progress and air quality planning goals specified below:

V.G.6.a. The resulting emission limits comply with the reduction requirements of Section V.D.5.c., and the baseline requirements of Section V.E.;

V.G.6.b. The bubble emission limits will be included in any new state implementation plan and associated control strategy demonstration;

V.G.6.c. The bubble will not constrain the Division's ability to obtain any additional emission reductions needed to expeditiously attain and maintain ambient air quality standards;

V.G.6.d. The Division is making reasonable efforts to develop a complete approvable state implementation plan and intends to adhere to the schedule for such development (including dates for completion of emission inventory and subsequent increments of progress) stated in or with the letter formally submitting the bubble.

V.G.7. Bubbles should not increase applicable net baseline emissions. Ordinarily, bubbles may not result in an increase in applicable net baseline emissions. Such a bubble would require a case-by-case state implementation plan revision, and may only be approved based upon a combined Level III and Level II modeling analysis (i.e., an analysis sufficient to show that all applicable requirements of a full Level III analysis are met, and that the bubble would not result in any exceedance of significance values specified for a Level II analysis at any receptor for any averaging time specified in an applicable ambient air quality standard).

V.G.8. Bubbles should not increase emissions of hazardous or toxic air pollutants.

V.H. Offset Transactions

V.H.1. The owner or operator of a source at which an emissions reduction has occurred, and the owner or operator of another source who wishes to use the emissions reduction as an offset, may apply for approval of an offset transaction. In such transactions certified emissions reductions may be applied to avoid causing a violation of an increment in an attainment or attainment/maintenance area, or to meet the requirements of Section V.A.3. of Part D of this regulation. A certified emissions reduction may not be used as an offset for the purpose of complying with an existing applicable emissions control regulation, except for Reasonably Available Control Technology.

V.H.2. The Division shall determine whether to approve an offset transaction in the following cases:

V.H.2.a. Where the source using the emissions reduction would be allowed to increase emissions by less than one hundred tons per year.

V.H.2.b. Where the transaction involves volatile organic compounds or oxides of nitrogen emissions.

V.H.2.c. Where the transaction involves sulfur dioxide, PM10 or carbon monoxide emissions, and all sources involved in the transaction are within two hundred and fifty meters of one another.

V.H.3. Any proposed offset transaction, other than those referred to in Section V.H.2., shall be treated as a request to the Commission for a state implementation plan revision.

V.H.4. Sources of PM10 precursors, sulfur dioxide, nitrogen oxide and carbon monoxide must seek offsets within reasonably close proximity. Sources of nitrogen oxide and volatile organic compounds may seek offsets over a greater area. However, for widely dispersed and volatile organic compound trades, a higher offset may be required.

V.H.5. If the applicant has used his best efforts in seeking the required emission offsets but was unsuccessful, the source may petition for use of some portion of growth allowance. The petition must state the emission increase will not interfere with Reasonably Further Progress and the petitioner is willing to enter into an enforceable program to provide the required emission offset at some future time.

V.H.6. In the absence of an approved attainment demonstration, banked Emission Reduction Credits from shutdowns or curtailments may be used for offsets only if the criteria stated in Section V.E.5.b. of Part A of this regulation are met.

V.H.7. In nonattainment areas with approved demonstrations, banked Emission Reduction Credits may be used for offsets in any trade provided the criteria stated in Section V.E.5.a. of Part A of this Regulation are met.

V.H.8. Interpollutant offsets (other than those offsets discussed above) may be approved by U.S. EPA on a case-by-case basis provided that the applicant demonstrates, on the basis of U.S. EPA-approved methods where possible, that the emissions increases from the new or modified source will not cause or contribute to a violation of an ambient air quality standard. A source's permit application that includes such an interpollutant offset proposal shall not be approved by the Division until there has been an opportunity for public hearing on the proposed emissions trade and until written approval has been received from the U.S. EPA.

V.I. Netting Transactions

V.I.1. Netting may exempt modifications of existing major sources from certain pre-construction permit requirements under new source review, so long as there is no significant net emission increase, as net emissions increase is defined in Section II.A.27. of Part D of this regulation. By netting out, the modifications is not considered major and therefore not subject to pre-construction permit requirements for major modifications as follows:

V.I.1.a. Section VI. of Part D of this regulation, for prevention of significant deterioration;

V.I.1.b. Visibility analysis; and

V.I.1.c. Section V.A. of Part D of this regulation, for nonattainment new source review.

V.I.2. The Division shall grant such an exemption if the emissions reduction qualifies as an Emission Reduction Credit under Regulation Number 3 meets the criteria in Section V.E., for certification, and the difference between the amount of the certified emissions reduction, and the amount of new pollutants to be emitted from the new or modified facility, does not constitute a significant increase of pollutants.

V.I.3. An increase of pollutants shall be considered significant if it equals or exceeds the amounts specified in the definition of significant in Part D of this regulation.

## VI. Fees

VI.A. General

VI.A.1. Every person required to obtain a Construction or Operating Permit or to file an Air Pollution Emission Notice shall pay fees as set forth in the following sections. Such fees shall be charged to recover the direct and indirect costs incurred by the Division in processing permit applications, issuing permits, and in conducting a compliance monitoring and enforcement program. Such fees shall apply without regard to whether a permit is issued, denied, withdrawn, or revoked. Fees shall be charged as indicated in Section VI.D. of this part.

VI.B. Permit Processing Fees

VI.B.1. Applicants for a permit shall be assessed total fees that shall be partially determined at the time that the Division makes its decision whether to issue preliminary approval of the permit and partially at the time the Division makes its decision whether to issue final approval.

VI.B.2. The partial fee collected at the time the Division makes its decision whether to issue preliminary approval of the permit shall include the costs associated with the preliminary engineering evaluation, modeling, and analysis of impact on ambient air quality, notice and publication requirements, and such other costs as are required for the aforementioned activities incurred by the Division up to the time of the decision of whether to issue preliminary approval.

VI.B.3. The final fee collected at the time the Division makes its decision of whether to issue final approval shall include the balance of the total of all costs associated with enforcement of any terms and conditions of the emission permit, the supervision of compliance testing, notice and publication requirements, and such other costs as are required for the processing, issuance, and administration of the permit.

VI.B.4. If the Division requires more than thirty hours to process an application, the Division shall inform the owner or operator of the source and provide an estimate of what the actual charges may be, prior to commencing with processing of the application, unless the owner or operator waives this requirement in writing.

VI.B.5. All permit processing fees assessed must be received within thirty days of the date of receipt of the written request therefore. All fees collected under this regulation shall be made payable to the Colorado Department of Public Health and Environment. Construction permits may be issued prior to the Division's receipt of such fees. Failure to pay the permit processing fees within ninety days of the written request for fees may result in late fees or revocation of the permit. Permits issued in accordance with Part C of this regulation may be issued upon approval by the Division of a fee payment schedule.

VI.C. Annual Emissions Fees

VI.C.1. As used in this Section VI., in accordance with Colorado Revised Statute Section 25-7-114.7, regulated air pollutant means:

VI.C.1.a. A volatile organic compound;

VI.C.1.b. Each hazardous air pollutant;

VI.C.1.c. Each pollutant regulated under Section 111 of the Federal Act (New Source Performance Standards), except GHG;

VI.C.1.d. Each pollutant for which a National Ambient Air Quality Standard has been promulgated, except for carbon monoxide; and

VI.C.1.e. Each pollutant regulated under Section 25-7-109, except GHG of the state Act.

VI.C.1.f. The term regulated air pollutant does not include fugitive dust as defined in Section I.B.21. of this Part A, or any fraction thereof.

VI.C.2. Every owner or operator of an air pollution source required to file an Air Pollutant Emission Notice shall pay a nonrefundable annual emissions fee as set forth in Section VI.D.1. of this Part A.

VI.C.3. All annual emissions fees assessed must be received within sixty days of the date of issuance of the written request therefore. All fees collected under this regulation shall be made payable to the Colorado Department of Public Health and Environment.

VI.C.4. In no event shall an owner or operator of a source pay more than a fee based upon total annual emissions of four thousand tons of each regulated air pollutant per source.

VI.D. Fee Schedule

VI.D.1. Annual emission fees and permit processing fees shall be charged in accordance with and in the amounts and limits specified in the provisions of Colorado Revised Statutes Section 25-7-114.7. Annual emission fees for regulated pollutants shall be $22.90 per ton. Annual emission fees for hazardous air pollutants shall be $152.90 per ton. GHG is exempt from the requirement to pay annual emission fees.

VI.D.2. Air Pollutant Emission Notice filing fees shall be charged in accordance with and in the amounts and limits specified in the provisions of Colorado Revised Statutes Section 25-7-114.1.

**VII. Confidential Information or Data Contained in Air Pollutant Emission Notices, Permit Applications, or Reports Submitted Pursuant to Part C, Section V.C.6.**

VII.A. Upon written request to the Division, any person filing an Air Pollutant Emission Notice or permit application, or submitting reports pursuant to Regulation Number 3, Part C, Sections V.C.6. or V.C.7., may request that information contained in such an Air Pollutant Emission Notice, permit application, or report relating to secret processes or methods of manufacture or production be kept confidential. The written request must identify the basis for the claim that the information relates to secret processes or methods of manufacture or production. All information claimed as confidential must be segregated from the rest of the Air Pollutant Emission Notice, permit application, or report when submitted, with each page clearly marked as "Confidential," "Trade Secret," or other similar marking.

VII.B. The Division will evaluate confidentiality claims based on the written request. The burden of establishing that the information relates to secret processes or methods of manufacture or production is on the claimant. Emission data, as defined in Colorado Revised Statutes Section 25-7-103(11.5), shall not be entitled to confidential treatment notwithstanding this Section VII., or any other law to the contrary. In no event shall an Operating Permit or the compliance certifications submitted pursuant to Section III.B.8. of Part C of this Regulation Number 3 be entitled to confidential treatment. If the Division determines that information requested to be kept confidential is not entitled to confidential treatment, it shall provide written notice of this determination at least three working days prior to making such information available to the public.

VII.C. A request for confidential treatment of information or data submitted to the Division shall be deemed a limited waiver by the applicant of the time constraints contained in Section III.B. of Part B, or Section IV. of Part C of this regulation. Therefore, any delay in the processing of a permit application resulting from the Division's being required to give notice under Section VII.B., hereof, shall not be considered in determining whether the time constraints set forth in this regulation have been met.

**VIII. Technical Modeling and Monitoring Requirements**

VIII.A. Air Quality Models

VIII.A.1. All estimates of ambient concentrations required under this Regulation Number 3 shall be based on the applicable air quality models, databases, and other requirements generally approved by U.S. EPA and specifically approved by the Division.

If a non-U.S. EPA approved model, such as a wind tunnel study, is proposed, the nature and requirements of such a model should be outlined to the Division at a pre-application meeting. The application will be deemed incomplete until there has been an opportunity for a public hearing on the proposed model and written approval of the U.S. EPA has been received.

VIII.B. Monitoring

VIII.B.1. All monitoring must be performed in accordance with U.S. EPA accepted procedures as approved by the Division.

VIII.B.2. An owner or operator may submit a monitoring program for a proposed source or modification to the Division for review. Within sixty days after such submittal, the Division shall:

VIII.B.2.a. Approve the monitoring program; or

VIII.B.2.b. Specify the changes necessary for approval; otherwise, the monitoring program shall be deemed approved.

VIII.C. Stack Heights

This regulation sets limits for the maximum stack height credit to be used in ambient air quality modeling for the purpose of setting an emission limitation and calculating the air quality impact of a source. It does not limit the actual physical stack height for any source. The following shall not be considered in determining whether an emission limitation is met:

VIII.C.1. Stack height in excess of good engineering practice; or

VIII.C.2. Any other dispersion technique except that the provisions of this Section VIII.C. shall not apply to stack heights in existence or dispersion techniques implemented before December 31, 1970. Sources that were constructed, reconstructed, or for which major modifications were carried out after December 31, 1970, and that are emitting pollutants from such stacks, or using such dispersion techniques, shall be subject to the provisions of this section.

VIII.D. Definitions as used in Section VIII.C.

VIII.D.1. Stack in existence means that the owner or operator had:

VIII.D.1.a. Begun, or caused to begin, a continuous program of physical on site construction of the stack; or

VIII.D.1.b. Entered into binding agreements or contractual obligations that could not be cancelled or modified without substantial loss to the owner or operator, to undertake a program of construction of the stack to be completed in a reasonable time.

VIII.D.2. Dispersion Technique means any technique that attempts to affect the concentration of a pollutant in the ambient air by using that portion of a stack that exceeds good engineering practice stack height, varying the rate of emission of a pollutant according to atmospheric conditions or ambient concentrations of that pollutant, or by increasing final exhaust gas plume rise by manipulating source process parameters, exhaust gas parameters, or combining exhaust gases from several existing stacks into one stack; or other selective handling of exhaust gas streams so as to increase the exhaust gas plume rise. The preceding sentence does not include:

VIII.D.2.a. The reheating of a gas stream, following use of a pollution control system, for the purpose of returning the gas to the temperature at which it was originally discharged from the facility generating the gas stream;

VIII.D.2.b. The merging of exhaust gas streams where:

VIII.D.2.b.(i) The source owner or operator demonstrates that the facility was originally designed and constructed with such merged gas streams;

VIII.D.2.b.(ii) After July 8, 1983, such merging is part of a change in operation at the facility that includes the installation of pollution controls and is accompanied by a net reduction in the allowable emissions of a pollutant. This exclusion from the definition of dispersion techniques shall apply only to the emission limitation for the pollutant affected by such change in operation; or

VIII.D.2.b.(iii) Before July 8, 1985, such merging was part of a change in operation at the facility that included the installation of emissions control equipment or was carried out for sound economic or engineering reasons. Where there was an increase in the emissions limitation or, in the event that no emission limitation was in existence prior to the merging, the reviewing agency shall presume that merging was significantly motivated by intent to gain emissions credit for greater dispersion.

Absent a demonstration by the source owner or operator that merging was not significantly motivated by such intent, the reviewing agency shall deny credit for the effects of such merging in calculating the allowable emissions for the source;

VIII.D.2.c. Smoke management in agricultural or silvicultural prescribed burning programs;

VIII.D.2.d. Episodic restrictions on residential wood burning and open burning; or

VIII.D.2.e. Techniques that increase final exhaust gas plume rise where the resulting allowable emissions of sulfur dioxide from the facility do not exceed five thousand tons per year.

VIII.D.3. Good Engineering Practice Stack Height means the greater of:

VIII.D.3.a. 65 meters; or

VIII.D.3.b. For stacks in existence on January 12, 1979 and for which the owner or operator had obtained all applicable pre-construction permits or approvals required, Hg = 2.5H, provided the owner or operator produces evidence that this equation was actually relied on in establishing an emission limitation; and

VIII.D.3.c. For all other stacks, Hg = H + 1.5L where:

VIII.D.3.c.(i) Hg = good engineering practice stack height measured from the ground level elevation at the base of the stack;

VIII.D.3.c.(ii) H = height of nearby structure(s) measured from the ground level elevation at the base of the stack;

VIII.D.3.c.(iii) L = lesser dimension (height or projected width) of nearby structure(s) provided that the reviewing agency may require the use of a field study or fluid model to verify Good Engineering Practice stack height for the source; or

VIII.D.3.d. The height demonstrated by a fluid model or a field study approved by the reviewing agency, which ensures that the emissions from a stack do not result in excessive concentrations of any air pollutant as a result of atmospheric downwash, wakes, or eddy effects created by the source itself, structures, or terrain obstacles.

VIII.D.4. Nearby as applied to good engineering practice is:

VIII.D.4.a. For purposes of applying the formulae provided in Sections VIII.D.3.b. and VIII.D.3.c. in the definition of good engineering practice stack height means that distance up to five times the lesser of the height or the width dimension of a structure, but not greater than 0.8 kilometers (1/2 mile), and

VIII.D.4.b. For conducting demonstrations in Section VIII.D.3. in the definition of good engineering practice means not greater than 0.8 kilometers (1/2 mile), except that the portion of a terrain feature may be considered to be nearby that falls within a distance of up to ten times the maximum height of the feature, not to exceed two miles if such feature achieves a height 0.8 kilometers from the stack that is at least forty percent of the good engineering practice stack height determine by the formula or twenty-six meters, whichever is greater.

VIII.D.5. Excessive concentrations for the purpose of determining good engineering practice, stack height in a fluid model or field study, means:

VIII.D.5.a. For sources seeking credit for stack height exceeding that established by the formulae, a maximum ground level concentration due to emissions from a stack due in whole or part to downwash, wakes, and eddy effects produced by nearby structures or nearby terrain features that individually is at least forty percent in excess of the maximum concentration experienced in the absence of such downwash, wakes, or eddy effects and that contributes to a total concentration due to emissions from all sources that is greater than an ambient air quality standard. For sources subject to the prevention of significant deterioration program, an excessive concentration alternatively means a maximum ground level concentration due to emissions from a stack due in whole or part to downwash, wakes, or eddy effects produced by nearby structures or nearby terrain features that individually is at least forty percent in excess of the maximum concentration experienced in the absence of such downwash, wakes, or eddy effects and greater than a prevention of significant deterioration increment. The allowable emission rate to be used in making demonstrations shall be prescribed by the new source performance standard that is applicable to the source category unless the owner or operator demonstrates that this emission rate is infeasible. Where such demonstrations are approved by the Division, an alternative emission rate shall be established in consultation with the source owner or operator;

VIII.D.5.b. For sources seeking credit after October 1, 1983 for increases in existing stack heights up to the heights established by the formulae, either:

VIII.D.5.b.(i) A maximum ground level concentration due in whole or part to downwash, wakes or eddy effects as provided in Section VIII.D.5.a. above, except that the emission rate specified by any applicable state implementation plan (or, in the absence of such a limit, the actual emission rate) shall be used; or

VIII.D.5.b.(ii) The actual presence of a local nuisance caused by the existing stack, as determined by the Division; and

VIII.D.5.b.(iii) For sources seeking credit after January 12, 1979 for a stack height determined using the formula, where the Division requires the use of a field study or fluid model to verify good engineering practice stack height; for sources seeking stack height credit after November 9, 1984 based on the aerodynamic influence of cooling towers; and for sources seeking credit after December 31, 1970 based on the aerodynamic influence of structures not adequately represented by the formulae: a maximum ground level concentration due in whole or part to downwash, wakes or eddy effects that is at least forty percent in excess of the maximum concentration experienced in the absence of such downwash, wakes or eddy effects.

**APPENDIX A De Minimis Level For Non-Criteria Reportable Pollutants**

An Air Pollutant Emission Notice must be filed for each emission point (individual or grouped) that has uncontrolled actual emissions equal to or greater than 250 pounds per year of any non-criteria reportable pollutant listed in Appendix B. As provided in Section II.C.4., sources submitting revised Air Pollutant Emission Notices due to Sections II.C.1.a., II.C.1.b., or II.C.1.e. must report actual annual emissions. Actual annual emissions for sources utilizing emission control equipment or procedures represent controlled actual annual emissions.

If a non-criteria reportable pollutant is not listed in Appendix B, it does not have to be reported unless it is included in a chemical compound group.

**Definitions**

Point - an individual emission point or a group of individual emission points reported on one Air Pollutant Emission Notice as provided for in Part A, Section II.B.4.

**APPENDIX B Non-criteria Reportable Pollutants (Sorted by CAS Number)**

Note: HAP means federal, or federal and state hazardous air pollutant

HAPs means state-only hazardous air pollutant

| | **CAS** | | **Toxics** |
|---|---|---|---|
| HAP | - | | Lindane (all isomers of hexachlorocyclohexane) |
| | - | | Thallium compounds |
| HAPs | - | | Nitrilotriacetic acid, Ca-, Na-, K salts |
| | - | | Ozone depleting compounds (CFC, etc.) |
| HAP | 0 | | Antimony compounds |
| HAP | 0 | | Arsenic compounds |
| HAP | 0 | | Beryllium compounds |
| HAP | 0 | | Cadmium compounds |
| HAP | 0 | | Chromium compounds (incl. 6+ compounds, etc.) |
| HAP | 0 | | Cobalt compounds (as cobalt metal dust and fumes) |
| HAP | 0 | | Coke Oven Emissions |
| HAP | 0 | | Cyanide compounds |
| HAP | 0 | | Fine mineral fibers |
| HAP | 0 | | Glycol ethers |
| HAP | 0 | | Lead compounds (except elemental lead) |
| HAP | 0 | | Manganese compounds |
| HAP | 0 | | Mercury compounds |
| HAP | 0 | | Nickel compounds (incl. nickel subsulfide) |
| HAP | 0 | | Polycyclic Organic Matter |

| | CAS | | Toxics |
|---|---|---|---|
| HAP | 0 | | Radionuclides (including radon) |
| HAP | 0 | | Selenium compounds |
| HAP | 50000 | | Formaldehyde |
| HAP | 51285 | | 2,4-Dinitrophenol |
| HAP | 51796 | | Ethyl carbamate (Urethane) |
| HAP | 53963 | | 2-Acetylaminofluorene |
| | 540885 | | Tertiary Butyl Acetate |
| | 54115 | | Nicotine |
| | 54626 | | Aminopterin |
| HAPs | 55185 | | N-Nitrosodiethylamine |
| | 55914 | | Isofluorphate |
| HAPs | 55981 | | 1,4-Butanediol dimethanesulphonate |
| HAP | 56235 | | Carbon tetrachloride |
| HAP | 56382 | | Parathion |
| | 56724 | | Coumaphos |
| HAP | 57147 | | 1,1-Dimethyl hydrazine |
| | 57249 | | Strychnine |
| HAP | 57578 | | Propiolactone, beta |
| HAP | 57749 | | Chlordane |
| HAP | 59892 | | N-Nitrosomorpholine |
| HAP | 60117 | | Dimethyl aminoazobenzene |
| HAP | 60344 | | Methyl hydrazine |
| HAP | 60355 | | Acetamide |
| | 60413 | | Strychnine sulfate |
| | 60515 | | Dimethoate |
| HAPs | 60571 | | Dieldrin |
| HAP | 62533 | | Aniline |
| HAP | 62737 | | Dichlorvos |
| | 62748 | | Sodium fluoroacetate |
| HAP | 62759 | | N-Nitrosodimethylamine |
| HAP | 63252 | | Carbaryl |
| | 64006 | | Phenol,3-(1-methylethyl)-methylcarbamate |
| HAP | 64675 | | Diethyl sulfate |
| | 66819 | | Cyclohexamide |
| HAP | 67561 | | Methanol (Methyl alcohol) |
| HAP | 67663 | | Chloroform (Trichloromethane) |
| HAP | 67721 | | Hexachloroethane |
| HAP | 68122 | | Dimethylformamide |
| HAP | 71432 | | Benzene |
| HAP | 71556 | | 1,1,1-Trichloroethane (Methyl chloroform) |
| | 72208 | | Endrin |
| HAP | 72435 | | Methoxychlor |
| HAP | 74839 | | Methyl bromide (Bromomethane) |
| HAP | 74873 | | Methyl chloride (Chloromethane) |
| HAP | 74884 | | Methyl iodide (Iodomethane) |
| | 74931 | | Methyl mercaptan (Methanethiol) |
| HAP | 75003 | | Ethyl chloride (Chloroethane) |
| HAP | 75014 | | Vinyl chloride |
| HAP | 75058 | | Acetonitrile |
| HAP | 75070 | | Acetaldehyde |
| HAP | 75092 | | Methylene chloride (Dichloromethane) |
| HAP | 75150 | | Carbon disulfide |

| | **CAS** | | **Toxics** |
|---|---|---|---|
| | 75183 | | Dimethyl sulfide (Methyl sulfide) |
| HAP | 75218 | | Ethylene oxide |
| HAP | 75252 | | Bromoform |
| HAP | 75343 | | Ethylidene dichloride (1,1-Dichloroethane) |
| HAP | 75354 | | 1,1-Dichloroethylene (Vinylidene chloride) |
| HAP | 75445 | | Phosgene |
| HAP | 75558 | | 1,2-Propylenimine (2-Methyl aziridine) |
| HAP | 75569 | | Propylene oxide |
| HAP | 76448 | | Heptachlor |
| HAP | 77474 | | Hexachlorocyclopentadiene |
| HAP | 77781 | | Dimethyl sulfate |
| | 77816 | | Tabun |
| | 78342 | | Dioxathion |
| | 78535 | | Amiton |
| HAP | 78591 | | Isophorone |
| HAP | 78875 | | Propylene dichloride (1,2-Dichloropropane) |
| | 78944 | | Methyl vinyl ketone (3-butene-2-one) |
| HAPs | 78988 | | Methylglyoxal |
| HAP | 79005 | | 1,1,2-Trichloroethane |
| HAP | 79016 | | Trichloroethylene (TCE) |
| HAP | 79061 | | Acrylamide |
| HAP | 79107 | | Acrylic acid |
| HAP | 79118 | | Chloroacetic acid |
| | 79196 | | Thiosemicarbizide |
| | 79210 | | Peracetic acid |
| | 79221 | | Methyl chloroformate |
| HAP | 79345 | | 1,1,2,2-Tetrachloroethane |
| HAP | 79447 | | Dimethyl carbamoyl chloride |
| HAP | 79469 | | 2-Nitropropane |
| HAP | 80626 | | Methyl methacrylate |
| | 81812 | | Warfarin |
| | 82666 | | Diphacinone |
| HAP | 82688 | | Pentachloronitrobenzene (Quintobenzene) |
| HAP | 84742 | | Dibutyl phthalate |
| HAP | 85449 | | Phthalic anhydride |
| | 86500 | | Methyl azinphos |
| | 86884 | | ANTU (alpha-naphthylthiourea) |
| HAP | 87683 | | Hexachlorobutadiene |
| HAP | 87865 | | Pentachlorophenol |
| | 88051 | | Aniline,2,4,6-Trimethyl |
| HAP | 88062 | | 2,4,6-Trichlorophenol |
| HAP | 90040 | | o-Anisidine |
| | 91087 | | 2,6-Toluene diisocyanate |
| HAP | 91203 | | Naphthalene |
| HAP | 91225 | | Quinoline |
| HAP | 91941 | | 3,3-Dichlorobenzidene |
| HAP | 92524 | | Biphenyl |
| HAP | 92671 | | 4-Aminobiphenyl |
| HAP | 92875 | | Benzidine (p-Diamino diphenyl) |
| HAP | 92933 | | 4-Nitrobiphenyl |
| HAP | 94757 | | 2,4-D, salts and esters (2,4-Dichlorophenoxyacetic acid) |
| HAP | 95476 | | o-Xylene |

| | CAS | | Toxics |
|---|---|---|---|
| HAP | 95487 | | o-Cresol |
| HAP | 95534 | | o-Toluidine |
| HAP | 95807 | | 2,4-Toluene diamine |
| HAP | 95954 | | 2,4,5-Trichlorophenol |
| HAP | 96093 | | Styrene oxide |
| HAP | 96128 | | 1,2-Dibromo-3-chloropropane |
| HAP | 96457 | | Ethylene thiourea |
| HAP | 98077 | | Benzotrichloride |
| HAP | 98828 | | Cumene |
| HAP | 98862 | | Acetophenone |
| | 98873 | | Benzal chloride [(Dichloromethyl)benzene; benzylidenechloride] |
| HAP | 98953 | | Nitrobenzene |
| | 99989 | | Dimethyl-p-phenylenediamine |
| HAP | 100027 | | 4-Nitrophenol |
| HAP | 100414 | | Ethyl benzene (Phenylethane) |
| HAP | 100425 | | Styrene |
| HAP | 100447 | | Benzyl chloride, (Chloromethyl)benzene |
| HAP | 101144 | | 4,4-Methylene bis (2-chloroaniline) |
| HAP | 101688 | | Methylene diphenyl diisocyanate (MDI) |
| HAP | 101779 | | 4,4-Methylenedianiline |
| HAP | 106423 | | p-Xylene |
| HAP | 106445 | | p-Cresol |
| HAP | 106467 | | 1,4-Dichlorobenzene |
| HAP | 106503 | | p-Phenylenediamine |
| HAP | 106514 | | Quinone |
| HAP | 106887 | | 1,2-Epoxybutane |
| HAP | 106898 | | Epichlorohydrin (1-Chloro-2,3-epoxypropane) |
| HAP | 106934 | | Ethylene dibromide (1,2-Dibromoethane) |
| | 106967 | | Propargyl bromide |
| HAP | 106990 | | 1,3-Butadiene |
| HAP | 107028 | | Acrolein |
| HAP | 107051 | | Allyl chloride |
| HAP | 107062 | | Ethylene dichloride (1,2-Dichloroethane) |
| | 107073 | | Chloroethanol |
| HAP | 107131 | | Acrylonitrile |
| | 107153 | | Ethylene diamine |
| | 107186 | | Allyl alcohol |
| HAP | 107211 | | Ethylene glycol |
| HAP | 107302 | | Chloromethyl methyl ether |
| | 107448 | | Sarin |
| | 107493 | | TEPP (Tetraethyldithiopyrophosphate) |
| HAP | 108054 | | Vinyl acetate |
| HAP | 108101 | | Methyl isobutyl ketone (MIBK) (Hexone) |
| | 108236 | | Isopropyl chlorformate |
| HAP | 108316 | | Maleic anhydride |
| HAP | 108383 | | m-Xylene |
| HAP | 108394 | | m-Cresol |
| HAP | 108883 | | Toluene |
| HAP | 108907 | | Chlorobenzene |
| | 108918 | | Cyclohexylamine |
| HAP | 108952 | | Phenol |
| | 108985 | | Thiophenol (Phenyl mercaptan) |

| | CAS | | Toxics |
|---|---|---|---|
| | 110009 | | Furan |
| HAP | 110543 | | Hexane |
| | 110576 | | Trans 1,4-dichlorobutene |
| | 110894 | | Piperidine |
| HAP | 111422 | | Diethanolamine |
| HAP | 111444 | | Dichloroethyl ether (Bis(2-chloroethyl)ether) |
| HAP | 114261 | | Propoxur (Baygon) |
| | 115264 | | Dimefox |
| HAPs | 115286 | | Chlorendic acid |
| | 115297 | | Endosulfan |
| | 115902 | | Fensulfothion |
| | 116063 | | Aldicarb (Temik) |
| HAPs | 117102 | | Chrysazin (Dorbane) |
| HAP | 117817 | | Bis(2-ethylhexyl) phthalate (DEHP) (Dioctyl phthalate) |
| HAP | 118741 | | Hexachlorobenzene |
| | 119380 | | Isopropylmethylpyrazolyl dimethylcarbamate (Isolan) |
| HAP | 119904 | | 3,3-Dimethoxybenzidine |
| HAP | 119937 | | 3,3'-Dimethyl benzidine |
| HAP | 120809 | | Catechol |
| HAP | 120821 | | 1,2,4-Trichlorobenzene |
| HAP | 121142 | | 2,4-Dinitrotoluene |
| HAP | 121448 | | Triethylamine |
| HAP | 121697 | | N,N-Diethyl aniline (N,N-Dimethylaniline) |
| | 122145 | | Fenitrothion |
| HAPs | 122601 | | Phenyl glyceryl ether (3 phenoxy 1,2 propanediol) |
| HAP | 122667 | | 1,2-Diphenylhydrazine |
| HAP | 123319 | | Hydroquinone |
| HAP | 123386 | | Propionaldehyde |
| | 123739 | | Crotonaldehyde (E) |
| HAP | 123911 | | 1,4-Dioxane (1,4-Diethyleneoxide) |
| | 126987 | | Methacrylonitrile |
| HAP | 126998 | | Chloroprene (2-Chloro-1,3-butadiene) |
| HAP | 127184 | | Perchloroethylene (Tetrachloroethylene) |
| | 129066 | | Warfarin sodium |
| HAP | 131113 | | Dimethyl phthalate |
| | 131522 | | Sodium pentachlorophenate |
| HAPs | 132274 | | 2-Biphenylol sodium salt |
| HAP | 132649 | | Dibenzofurans |
| HAP | 133062 | | Captan |
| HAP | 133904 | | Chloramben (3-amino-2,5-dichloro benzoic acid) |
| | 140761 | | Pyridine, 2-methyl-5-vinyl |
| HAP | 140885 | | Ethyl acrylate |
| | 141662 | | Dicrotophos |
| | 144490 | | Fluoracetic acid |
| | 149746 | | Dichloromethylphenylsilane |
| HAP | 151564 | | Ethylene imine (Aziridine) |
| | 152169 | | Diphosphoramide, octamethyl |
| HAP | 156627 | | Calcium cyanamide |
| | 297789 | | Isobenzan |
| | 297972 | | Thionazin (O,O-Diethyl-O-(2-pyrazinyl)phosphorothioate) |
| | 298000 | | Parathion-methyl |
| | 298022 | | Phorate |

| | **CAS** | | **Toxics** |
|---|---|---|---|
| | 298044 | | Disulfoton |
| HAP | 302012 | | Hydrazine |
| HAPs | 309002 | | Aldrin |
| | 315184 | | Mexacarbate |
| HAP | 334883 | | Diazomethane |
| | 359068 | | Fluoroacetyl chloride |
| | 371620 | | Ethylene fluorohydrin |
| HAP | 463581 | | Carbonyl sulfide |
| | 465736 | | Isodrin |
| | 470906 | | Chlorfenvinfos |
| | 505602 | | Mustard gas (Dichlorodiethyl sulfide) |
| | 509148 | | Tetranitromethane |
| HAP | 510156 | | Chlorobenzilate (ethyl-4,4'-dichlorobenzilate) |
| HAP | 532274 | | 2-Chloroacetophenone |
| | 534076 | | Bis(chloromethyl)ketone |
| HAP | 534521 | | 4,6-Dinitro o-cresol, and salts |
| | 535897 | | Crimidine |
| | 538078 | | Ethyl bis (2-chloroethyl)amine |
| HAP | 540841 | | 2,2,4-Trimethylpentane |
| | 541537 | | Dithiobiuret |
| HAP | 542756 | | 1,3-Dichloropropene |
| HAP | 542881 | | Bischloromethyl ether |
| | 542905 | | Ethylthiocyanate |
| | 555771 | | Tris(2-chloroethyl)amine |
| | 556616 | | Methyl isothiocyanate |
| | 563122 | | Ethion |
| HAP | 584849 | | 2,4-Toluene diisocyanate |
| HAP | 593602 | | Vinyl bromide |
| HAPs | 615532 | | N-nitroso-N-methylurethane |
| HAP | 624839 | | Methyl isocyanate |
| | 624920 | | Methyl disulfide |
| | 625558 | | Isopropyl formate |
| | 640197 | | Fluoroacetamide |
| | 644644 | | Dimetilan |
| | 675149 | | Cyanuric fluoride |
| HAP | 680319 | | Hexamethylphosphoramide |
| HAP | 684935 | | N-nitroso-N-methylurea |
| | 732116 | | Phosmet |
| | 786196 | | Carbophenothion |
| | 814686 | | Acrylyl chloride |
| HAP | 822060 | | Hexamethylene-1,6-diisocyanate |
| | 919868 | | Demeton-s-methyl |
| HAPs | 924163 | | N-Nitroso-di-n-butylamine |
| | 944229 | | Fonofos |
| | 947024 | | Phosfolan |
| | 950107 | | Mephosfolan |
| | 950378 | | Methidathion |
| | 991424 | | Norbormide |
| HAP | 1120714 | | 1,3-Propane sultone |
| | 1122607 | | Nitrocyclohexane |
| | 1314847 | | Zinc phosphide |
| HAP | 1319773 | | Cresylic acid/Cresols |

| | **CAS** | | **Toxics** |
|---|---|---|---|
| HAP | 1330207 | | Xylene (and mixed isomers) |
| HAP | 1332214 | | Asbestos |
| HAP | 1336363 | | Polychlorinated biphenyls (PCBs) (Aroclors) |
| | 1397940 | | Antimycin A |
| HAPs | 1402682 | | Aflatoxins |
| | 1420071 | | Dinoterb |
| | 1464535 | | Diepoxybutane |
| | 1563662 | | Carbofuran |
| HAP | 1582098 | | Trifluralin |
| HAP | 1634044 | | MTBE (Methyl tertiary butyl ether) |
| | 1642542 | | Diethylchlorophosphate |
| HAP | 1746016 | | 2,3,7,8-TCDD (Dioxin) |
| | 1910425 | | Paraquat |
| | 1982474 | | Chloroxuron |
| | 2001958 | | Valinomycin |
| | 2032657 | | Methiocarb |
| | 2074502 | | Paraquat methosulfate |
| HAPs | 2475458 | | Disperse Blue 1 |
| | 2497076 | | Oxydisulfoton |
| | 2524030 | | Dimethylphosphorochloridothioate |
| | 2540821 | | Formothion |
| | 2631370 | | Promecarb |
| | 2642719 | | Ethyl azinphos |
| HAPs | 2646175 | | CI Solvent Orange 2 |
| | 2778043 | | Endothion |
| HAP | 3547044 | | DDE (Dichlorodiphenyldichloroethylene) |
| | 3689245 | | Sulfotep |
| | 3691358 | | Chlorophacinone |
| | 3734972 | | Amiton oxalate |
| | 3735237 | | Methyl phenkapton |
| | 3878191 | | Fuberidazole |
| | 4098719 | | Isophorone diisocyanate |
| | 4170303 | | Crotonaldehyde |
| | 4301502 | | Fluenetil |
| | 4835114 | | Hexamethylenediamine, N,N-dibutyl |
| | 5836293 | | Coumatetralyl |
| | 7446119 | | Sulfur trioxide |
| HAP | 7550450 | | Titanium tetrachloride |
| HAPs | 7644410 | | 1,4-Dichloro-2-butene |
| HAP | 7647010 | | Hydrochloric acid (Hydrogen chloride) |
| HAP | 7664393 | | Hydrogen fluoride (Hydrofluoric acid) |
| | 7664417 | | Ammonia |
| | 7664939 | | Sulfuric acid |
| | 7697372 | | Nitric acid |
| HAP | 7723140 | | Phosphorous |
| | 7726956 | | Bromine |
| | 7782414 | | Fluorine |
| HAP | 7782505 | | Chlorine |
| | 7783064 | | Hydrogen sulfide |
| | 7786347 | | Mevinphos |
| HAP | 7803512 | | Phosphine |
| HAP | 8001352 | | Toxaphene (Camphechlor) |

| | CAS | | Toxics |
|---|---|---|---|
| | 8065483 | | Demeton |
| | 10265926 | | Methamidophos |
| | 10294345 | | Boron trichloride |
| | 10311849 | | Dialifor |
| | 13071799 | | Terbufos |
| | 13171216 | | Phosphamidon |
| | 13194484 | | Ethoprophos (Ethoprop) |
| | 13494809 | | Tellurium |
| | 16752775 | | Methomyl |
| | 17702577 | | Formparanate |
| | 19287457 | | Diborane |
| | 20859738 | | Aluminum phosphide |
| | 21548323 | | Fosthietan |
| | 21609905 | | Leptophos |
| | 21923239 | | Chlorthiophos |
| | 22224926 | | Fenaminophos (Fenamiphos) |
| | 23135220 | | Oxamyl |
| | 23422539 | | Formotanate hydrochloride |
| | 23505411 | | Pirimifos-ethyl |
| | 24934916 | | Chlormephos |
| | 28347139 | | Xylylene dichloride |
| | 28772567 | | Bromodiolone |
| | 53558251 | | Pyriminil |
| HAPs | 60153493 | | 3-(N-Nitrosomethylamine) (Propionitrile) |
| HAPs | 64091914 | | Ketone, 3-pyridyl-3-(N-methyl-N-nitrosoamino) propyl |
| HAPs | 108171262 | | Chlorinated paraffins (C12, 60% chlorine) |

## PART B CONCERNING CONSTRUCTION PERMITS

### I. Applicability

I.A. The provisions of this Part B shall apply statewide. All sources that did not commence construction or operation prior to February 1, 1972, are required to have a construction permit except as specified in Section II.

### II. General Requirements For Construction Permits

II.A. General Considerations

II.A.1. Except where specifically authorized by the terms of this Regulation Number 3, no person shall commence construction of any stationary source or modification of a stationary source without first obtaining or having a valid construction permit from the Division.

II.A.2. Any permit that has been issued pursuant to a prior regulation of the Commission, with respect to a project or the operation thereof, shall continue in full force and effect for the purpose for that it was originally issued, unless this current regulation no longer requires such permit, in that case the permit can be rescinded upon request of the owner or operator of the permitted source.

II.A.3. Any orders or decisions of the Division shall be final upon issuance, according to Section III.F.3. of this Part B.

II.A.4. Construction permits for criteria pollutants, GHG and hazardous air pollutants shall be issued based on the production/process rate requested in the Air Pollutant Emission Notice submitted with the permit application or as requested in the application. The emission rate associated with the requested production/process rate shall be a permit condition. For permits to limit the potential to emit criteria, pollutants, GHG or hazardous air pollutants the Division may modify the production/process rate, hours of operation or other requested permit conditions in order to create state-only or federally and practically enforceable permit conditions; provided, however, that the applicant may decline to accept such modifications and elect instead to forego limits on its potential to emit or pursues any right of appeal or other available alternative. For details regarding permits to limit the potential to emit hazardous air pollutants see Regulation Number 8, Part E, Section IV.

II.A.5. Construction permits are required for hazardous air pollutants if:

II.A.5.a. The source is subject to Colorado Maximum Achievable Control Technology or Generally Available Control Technology.

II.A.6. Owners or operators of sources that have valid operating permits in accordance with Part C of this regulation may construct or modify such source without obtaining a construction permit prior to construction or modification, provided the construction or modification qualifies for a minor permit modification or for operational flexibility, and the applicable provisions as set forth in Sections X., XI., or XII. of Part C are met. In addition, all applicable requirements that are related to construction permit approval and that are set forth in Sections III.D.1.a. through III.D.1.g. of this Part B remain in effect.

II.A.7. A source that is voluntarily applying for a permit to create state-only or federally enforceable permit conditions, as appropriate, to limit the potential to emit criteria, pollutants, GHG or hazardous air pollutants may request to obtain such limits in a construction permit.

II.B. Transfer or Assignment of Ownership

If transfer or assignment of ownership or operation of an air pollution emission source permitted pursuant to this Part B is anticipated, the prospective owner or operator shall apply to the Division on Division supplied administrative permit amendment forms for reissuance of the existing permit. Section III. of Part A of this regulation governs the administrative permit amendment procedures required for transfer or assignment of ownership.

In accordance with the provisions of this section, the permit shall be reissued upon completion of the transfer or assignment if the applicant certifies that no change is contemplated that might constitute a new or modified air pollution source. In no event shall the new owner or operator of a source that was subject to the requirements of these regulations prior to the transfer or assignment be relieved of the obligation to comply with such requirements by reason of a transfer. Such transfers are subject to all applicable permit processing and inspection fees.

If a company is changing its name only, the owner or operator shall apply to the Division, on Division supplied administrative permit amendment forms, for reissuance of the existing permit. Section III. of Part A, governs the administrative permit amendment procedures required for identifying a change in name. If all other procedures and information as stated in the last submitted Air Pollutant Emission Notice(s) remains unchanged, only one Air Pollutant Emission Notice need be submitted for each stationary source, indicating the name change.

No administrative permit amendment for transfer or assignment of ownership of a source shall be complete until a written agreement containing a specific date for transfer of permit, responsibility, coverage and liability between the current and new permittee is received by the Division.

II.C. Portable Sources

A permitted portable source (e.g., asphalt plants, crushers, etc.) shall have its permit number permanently and prominently displayed on each major component of equipment that is a part of that portable source.

II.D. Exemption from Construction Permit Requirements

Permit exemptions taken under this section do not affect the applicability of any State or Federal regulations that are otherwise applicable to the source.

An applicant may not omit any information regarding APEN or permit exempt emission units in any application if such information is needed to determine the applicability of Title V (Part C of this Regulation Number 3), Prevention of Significant Deterioration (Section VI. of Part D of this Regulation Number 3), or Nonattainment New Source Review (Section V. of Part D of this Regulation Number 3).

II.D.1. The following sources are exempt because by themselves, or cumulatively as a category, they are deemed to have a negligible impact on air quality:

II.D.1.a. Those sources exempted from the filing of Air Pollutant Emission Notices in Section II.D. of Part A, of this regulation.

II.D.1.b. Containers, reservoirs, or tanks used exclusively for dipping operations for coating objects with oils, waxes, greases, or natural or synthetic resins containing no organic solvents.

II.D.1.c. Stationary Internal Combustion Engines that:

II.D.1.c.(i) Are power portable drilling rigs; or

II.D.1.c.(ii) Are emergency power generators that operate no more than two hundred and fifty hours per year; or

II.D.1.c.(iii) Have uncontrolled actual emissions less than five tons per year or manufacturer's site-rated horsepower of less than fifty.

II.D.1.d. The collection, transmission, liquid treatment, and solids treatment processes at domestic wastewater treatment works, or treatment facilities that treat only domestic type wastewater, except for combustion processes.

II.D.1.e. Each individual piece of fuel burning equipment, other than smokehouse generators, that uses gaseous fuel, and that has a design rate less than or equal to ten million British thermal units per hour.

II.D.1.f. Gasoline stations located in ozone attainment areas, except for stations located in the Denver 1-hour ozone attainment/maintenance area.

II.D.1.g. Surface mining activities that mine seventy thousand tons or fewer of product material per year. A fugitive dust control plan is required for such sources. Crushers, screens and other processing equipment activities are not included in this exemption.

II.D.1.h. Composting piles, however, all odor requirements of Regulation Number 2 must be met.

II.D.1.i. Commercial and product quality control laboratory equipment.

II.D.1.j. Fires and equipment used for noncommercial cooking of food for human consumption and for cooking of food for human consumption at commercial food service establishments.

II.D.1.k. Petroleum industry flares, not associated with refineries, combusting natural gas containing no hydrogen sulfide except in trace (less than five hundred parts per million weight) amounts, approved by the Colorado Oil and Gas Conservation commission and having uncontrolled emissions of any pollutant of less than five tons per year.

II.D.1.l. Crude oil truck loading equipment at exploration and production sites where the loading rate does not exceed 10,000 gallons of crude oil per day averaged on an annual basis. Condensate truck loading equipment at exploration and production sites that splash fill less than 6750 barrels of condensate per year or that submerge fill less than 16308 barrels of condensate per year.

II.D.1.m. Oil and gas production wastewater impoundments (including produced water tanks) containing less than one percent by volume crude oil on an annual average, with the exception of commercial facilities that accept oil and gas production wastewater for processing.

II.D.1.n. Exemption Repealed.

II.D.2. Facilities located in a nonattainment area for any criteria pollutant for which the area is nonattainment; with total facility uncontrolled actual emissions (potential emissions at actual operating hours) that are less than the following amounts:

II.D.2.a. Two tons per year volatile organic compounds.

II.D.2.b. One ton per year PM10.

II.D.2.c. One ton per year PM2.5.

II.D.2.d. Five tons per year total suspended particulate.

II.D.2.e. Five tons per year carbon monoxide.

II.D.2.f. Five tons per year sulfur dioxide.

II.D.2.g. Five tons per year nitrogen oxides.

II.D.2.h. Two hundred pounds per year lead.

For purposes of calculating total facility uncontrolled actual emissions, only those individual (or grouped) emission points requiring Air Pollutant Emission Notices are to be considered.

II.D.3. Facilities located in attainment or attainment/maintenance areas for all criteria pollutants with total facility uncontrolled actual emissions less (potential emissions at actual operating hours) than the following amounts:

II.D.3.a. Five tons per year volatile organic compounds.

II.D.3.b. Five tons per year PM10.

II.D.3.c. Five tons per year PM2.5.

II.D.3.d. Ten tons per year total suspended particulate.

II.D.3.e. Ten tons per year carbon monoxide.

II.D.3.f. Ten tons per year sulfur dioxide.

II.D.3.g. Ten tons per year nitrogen oxides.

II.D.3.h. Two hundred pounds per year lead.

For purposes of calculating total facility uncontrolled actual emissions, only those individual (or grouped) emission points requiring Air Pollutant Emission Notices are to be considered.

II.D.4. Facilities that emit any other criteria pollutant that is not listed in Sections II.D.2. and II.D.3., above (fluorides, sulfuric acid mist, hydrogen sulfide, total reduced sulfur, reduced sulfur compounds, and municipal waste combustor emissions), with total facility uncontrolled actual emissions of such pollutants that are less than two tons per year.

II.D.5. When a facility that was previously exempt from permit requirements exceeds one of the permit de minimis levels stated in Sections II.D.2. through II.D.4., above, due to the addition of new emission points, the Division will issue either a facility-wide permit for all non-grandfathered emission units above Air Pollutant Emission Notice de minimis levels, or individual emission permits for those emission units.

II.D.6. All incinerators require a permit as stated in Regulation Number1, Section III.B.1.

II.D.7. Oil and gas exploration and production operations that are addressed under Section II.D.1.lll. of this Regulation Number 3, Part A, and that are required to obtain a construction permit, are not required to file an application for a construction permit until they are required to file an Air Pollutant Emission Notice, as set forth in Section II.D.1.lll. The application shall include a list of all applicable requirements, and how the requirements will be met until a construction permit is issued.

II.D.8. Any person may request the Division to add source categories to the permit exemption list, in accordance with the procedures set forth in Section II.D.4. of Part A of this regulation.

II.D.9. Sources with a valid operating permit are not required to obtain a construction permit prior to commencing construction or modification, as set forth in Section II.A.6. of this Part B.

## III. Construction Permit Review Procedures

III.A. Option for Pre Application Meeting

Prior to submitting an application for a permit, an applicant may request and, if so requested, the Division shall grant, a pre-application meeting with the applicant. At such meeting, the Division shall advise the applicant of the applicable permit requirements, including the information, plans, specifications and the data required to be furnished with the permit application.

III.B. Application for a Construction Permit

III.B.1. An application for a Construction Permit shall be prepared on forms currently supplied by the Division.

III.B.2. Applications for Construction Permits, and modifications to Construction Permits, must include an Air Pollutant Emission Notice.

III.B.3. Applications shall be signed by a person legally authorized to act on behalf of the applicant. The applicant shall furnish all information and data required by the Division to evaluate the permit application and to make its preliminary analysis in accordance with Section III.B.5. of this part.

III.B.4. An application for a Construction Permit will not be deemed to be complete until all information and data required to evaluate the application have been submitted to the Division. Within sixty calendar days after the receipt of an application or any supplemental information timely requested by the Division, the Division will give notice to the applicant if and in what respect the application is incomplete. If the Division fails to notify an applicant that the application is incomplete within sixty calendar days of receipt of the original application or receipt of the requested supplemental information, the application shall be deemed to have been complete as of the day of receipt by the Division of the application or the last submitted supplemental information, whichever is later.

III.B.5. Except for applications for sources subject to the requirements of Section VI. of Part D of this regulation (Prevention of Significant Deterioration), the Division shall prepare its preliminary analysis within sixty calendar days after receipt of a complete permit application. The preliminary analysis allows the Division to determine whether the new source will, at date of commencement of operation, comply with:

III.B.5.a. All applicable emission control regulations,

III.B.5.b. Applicable regulations for the control of hazardous pollutants,

III.B.5.c. Requirements of the nonattainment and attainment programs (Sections V. and VI. of Part D), and

III.B.5.d. Any applicable ambient air quality standards and all applicable regulations.

The preliminary analysis shall indicate what impact, if any, the new source will have (as of the projected date of commencement of operation) on all areas (attainment, attainment/maintenance, nonattainment, unclassifiable), within the probable area of influence of the proposed source. If so requested on the permit application form, a copy of this preliminary analysis shall be forwarded to the applicant postmarked no later than fifteen calendar days after the completion of the preliminary analysis.

When the preliminary analysis includes modeling, the model used shall be an appropriate one given the topography, meteorology and other characteristics of the region that the source will impact. Use of any non-guideline model requires U.S. EPA approval under Section VIII.A. of Part A of this regulation.

III.C. Public Comment and Hearing Requirements

III.C.1. The following sources, unless exempted in Section III.C.2., below, are subject to public comment:

III.C.1.a. Sources with projected controlled annual emissions of any pollutant for which an ambient air quality standard has been designated, where such emissions will be greater than twenty five tons per year if the source is located in a nonattainment area, fifty tons per year if the source is located in an attainment or attainment/maintenance area, or two hundred pounds per year of lead (for any area of the state).

III.C.1.b. Sources for which preliminary analysis indicates a possible violation of Commission Regulation Number 2 (odor emissions).

III.C.1.c. For hazardous air pollutants if:

III.C.1.c.(i) The source is subject to Federal National Emission Standards for Hazardous Air Pollutants,

III.C.1.c.(ii) The source is subject to Federal or Colorado Maximum Achievable Control Technology or Generally Available Control Technology standards, or

III.C.1.c.(iii) The source is voluntarily applying for permit conditions to limit the source's potential to emit hazardous air pollutants.

III.C.1.d. Sources subject to Sections V. or VI. of Part D of this regulation that are attempting to obtain a federally enforceable limit on the potential to emit of the source in order to avoid other requirements.

III.C.1.e. Sources submitting an application for a BART determination or BART alternative pursuant to Regulation Number 3, Part F.

III.C.2. The following sources are generally not required to be subject to public comment, unless the Division determines that public comment is warranted pursuant to Section III.C.3. below:

III.C.2.a. Sources of six months duration or less, except that public comment shall be required for all major sources of hazardous pollutants without regard to the duration of the operation of such source unless specifically exempted below.

III.C.2.b. Demolition projects, even if asbestos materials are present, provided that all the requirements of Regulation Number 8 are followed for any and all materials suspected of containing asbestos.

III.C.2.c. Construction or modification of sources in accordance with the minor modification and operational flexibility provisions of Sections X., XI., and XII. of Part C of this regulation are subject to the public participation requirements of Part C.

III.C.3. Sources for which a permit is required, but for which public comment is not required by Sections III.C.1., III.C.2.a., or III.C.2.b., above, are exempt from public comment requirements unless the Division determines that public comment is warranted. In making such determinations, the Division shall take into consideration the duration of the operation, its location, the nature and projected amount of emissions, anticipated public concern, and other relevant factors.

III.C.4. When public comment is required by Section III.C.1., or when the Division determines, pursuant to Section III.C.3., that an application warrants public comment, the Division shall, within fifteen calendar days after the preparation of the preliminary analysis, cause public notice of the application to be published in a newspaper of general distribution in the area in which the proposed project or activity is or will be located, or by such other means necessary to assure notice to the affected public, that may include posting of such notice on the publicly accessible portion of the Division's web site. The Division shall cause a copy of the application, the preliminary analysis, and the draft permit to be filed with the county clerk for each county in which the source is, or will be located. The Division shall send written or electronic notice to persons requesting notice of permit applications that are subject to public notice requirements. For sources applying for a permit to limit the potential to emit criteria pollutants or federal hazardous air pollutants, the Division shall send a copy of the public notice and the draft permit to the U.S. EPA Administrator for comment. The Division shall also send a copy of the final permit approval to the U.S. EPA Administrator for comment. The newspaper notice or other such means of notice shall contain all of the following information in Sections III.C.4.a. through III.C.4.e., below:

III.C.4.a. The location and nature of the proposed project or activity for which a construction permit application has been filed.

III.C.4.b. The locations where the application and preliminary analysis are available for public inspection.

III.C.4.c. That comments concerning the ability of the proposed project or activity to comply with the applicable standards and regulations of the Commission are solicited from any interested person.

III.C.4.d. That the Division will receive and consider public comments for thirty calendar days after such publication.

III.C.4.e. The Division's preliminary determination of approval, conditional approval, or disapproval of the application.

III.D. Construction Permit Review Requirements

III.D.1. Requirements applicable to all construction permit applications (except that processing timeframes of combined construction/operating applications shall be as set forth in Part C, Section IV., of this Regulation Number 3). Within thirty calendar days following the completion of the Division's preliminary analysis for applications not subject to the public comment, within thirty calendar days following the period for public comment for applications subject to public comment, or if a public comment hearing is held, within thirty calendar days following such hearing, the Division shall grant the permit if it finds that:

III.D.1.a. The proposed source or activity will meet all applicable emission control regulations and regulations for the control of hazardous air pollutants;

III.D.1.b. As applicable, the proposed source or activity will meet the requirements of the attainment program as outlined in Section V. of Part D of this regulation, if any;

III.D.1.c. The proposed source or activity will not cause an exceedance of any National Ambient Air Quality Standards;

III.D.1.d. The source or activity will meet any applicable ambient air quality standards and all applicable regulations;

III.D.1.e. As applicable, the proposed source or modification will meet the requirements of the prevention of significant deterioration program of Section VI. of Part D of this regulation.

[Provided however, that the Division shall not deny a permit for failure of the proposed source to meet any applicable requirement of the state implementation plan where (1) there is pending an application for a revision to the state implementation plan pursuant to Colorado Revised Statute, Section 25-7-305 (Alternative Emission Reduction) that, if adopted, would require the Division to grant the permit and (2) the applicant waives the time constraints on the Division to act on its application until the Commission has issued its final decision on the request for a state implementation plan revision and the U.S. EPA has acted on the proposed revision to the state implementation plan. In such circumstances, the Division shall delay its decision on the permit application until after final action on the request for revision of the state implementation plan (including action by the U.S. EPA)];

III.D.1.f. The fees required in Section VI. of Part A of this regulation have been paid;

III.D.1.g. Permit approval shall not relieve any owner or operator of the responsibility to comply fully with applicable provisions of the state implementation plan and any other requirements under local, state, or federal law.

III.D.2. RACT Requirements for new or modified Minor Sources (including new or modified minor emissions units at major stationary sources) of volatile organic compounds, carbon monoxide, nitrogen oxides, sulfur dioxide, and PM10 in nonattainment and attainment/maintenance areas:

III.D.2.a. Minor sources in designated nonattainment or attainment/maintenance areas that are otherwise not exempt pursuant to Section II.D. of this Part, shall apply Reasonably Available Control Technology for the pollutants for which the area is nonattainment or attainment/maintenance.

III.D.2.b. In the Denver Metropolitan PM10 attainment/maintenance area, for any new minor source with a potential to emit forty tons per year or more of nitrogen oxides or sulfur dioxide, or a modification of an existing minor source with a net emissions increase of forty tons per year or more of nitrogen oxides or sulfur dioxide, the source will install Reasonably Available Control Technology.

III.E. Permit Terms and Conditions

The Division shall include such terms and conditions in any permit as it deems necessary for the proposed project or activity to qualify for the permit.

III.F. Denial or Revocation of the Construction Permit

III.F.1. If the Division determines that a source cannot comply with the provisions of Part B, Section III.D., of this regulation, the Division shall issue its written denial of the permit application stating the reasons for such denial. Any Division denial of a permit shall become final upon mailing of the denial notice to the applicant by certified mail. The applicant may appeal the Division's final denial of a permit as provided in Section III.F.3., below.

III.F.2. Any applicant for a construction permit shall advise the Division in writing of any refusal to accept any permit condition imposed by the Division within twenty calendar days after receipt of the permit. Such refusal shall be deemed a denial of the permit application.

III.F.3. If the Division denies a permit, imposes conditions upon a permit that are contested by the applicant, revokes a permit, or requires a permit from a source that may qualify for an exemption, the applicant or owner or operator of a source may request a hearing before the Commission for review of the Division's action. The request for a hearing must be filed with the Commission within thirty days after the issuance of the permit, denial or revocation. The hearing shall be heard in accordance with the provisions of Section VI. of the Commission's Procedural Rules, Colorado Revised Statute Sections 25-7-114.5(8), and 25-7-119, (Colorado Air Pollution Prevention and Control Act) and Section 24-4-105, (State Administrative Procedure Act).

III.F.4. Initial Approval Expiration

III.F.4.a. An initially approved permit shall expire if the owner or operator of the source for which the permit was issued: (i) does not commence construction or operation of the source within eighteen months after either the date of issuance of the permit or the date on which such construction or activity was scheduled to commence as set forth in the permit, whichever is later; (ii) discontinues construction for a period of eighteen months or more; or (iii) does not complete construction within a reasonable time of the estimated completion date.

III.F.4.b. Upon a showing of good cause by the permittee, the Division may grant extensions of the permit not to exceed eighteen months per extension. Construction or operation shall commence or be resumed within a reasonable period of time from the granting of the extension. In determining what constitutes good cause or a reasonable period of time, the Division shall consider the degree of construction already completed, the amount invested or legally committed to the project, whether an extension would prevent (e.g., through reservation of a Prevention Significant Deterioration increment) economic development in the affected area, general economic conditions, the health of the community as it affects the ability of the permittee to proceed, and other relevant factors. The Division shall notify the Commission of any requested extensions and the reason given for each request.

III.G. Final Permit Approval

III.G.1. Unless prior and mutually acceptable arrangements have been made, the applicant shall give notice to the Division within fifteen calendar days after the date on which commencement of operation takes place.

III.G.2. Within 180 calendar days after commencement of operation, the source shall demonstrate to the Division compliance with the terms and conditions of the initial approval construction permit. The Division may inspect the source to determine whether or not the operating terms and conditions of the initial approval construction permit have been satisfied. At the end of 180 days, the Division must revoke the construction permit; or, continue the construction permit if applicable; or, notify the owner or operator that the source has demonstrated compliance with the construction permit.

III.G.3. Before final approval of the permit is granted, the Division may require the applicant to conduct and pay for performance tests in accordance with methods approved by the Division. A test protocol shall be submitted to the Division for review and approval at least thirty days prior to testing. The Division may monitor such tests and may, at its expense, conduct its own performance tests.

III.G.4. For sources that submit an application for an operating permit pursuant to Part C of this Regulation Number 3, including any application for a permit modification or permit renewal, prior to issuance of a final approval construction permit, upon demonstration by the source of compliance with all terms and conditions of the construction permit or a satisfactory final approval inspection, as required pursuant to this Section III.G., the Division may elect to either issue a final approval construction permit or allow the initial approval construction permit to continue in full force and effect. The Division shall provide written notice to the permittee of its election.

III.G.5. If the Division determines that the terms and conditions of the permit have been satisfied, the Division shall issue in writing its final permit approval to the applicant, or shall incorporate the terms and conditions into an operating permit issued in accordance with Part C of this regulation. Otherwise, the Division shall revoke the permit.

III.G.6. Final approval may be issued at the same time as initial approval for temporary sources of duration of one month or less.

III.G.7. Prior to issuance of final approval, the applicant shall furnish:

III.G.7.a. An operating and maintenance plan for all control equipment and control practices; and

III.G.7.b. A proposed record keeping format for demonstrating compliance on an ongoing basis.

III.H. Permit Cancellation

Whenever an owner or operator wishes to cancel a permit, the owner or operator shall notify the Division, using forms provided by the Division.

III.I. General Construction Permits

III.I.1. The Division may issue a general construction permit covering numerous similar sources to a source that would otherwise be required to obtain a construction permit pursuant to this Part B. Any general construction permit shall comply with all applicable requirements, including notice and opportunity for public participation where warranted for such sources. The Division may issue a general construction permit in accordance with one or more of the following considerations:

III.I.1.a. The control equipment utilized by the sources;

III.I.1.b. The design characteristics of the sources;

III.I.1.c. The operational variability of the sources;

III.I.1.d. The location of the sources.

III.I.2. A source shall not perform any of the following without first obtaining a valid general construction permit from the Division pursuant to this provision, or a valid construction permit as otherwise required pursuant to Section III. of this Part B:

III.I.2.a. Commence construction or modify any building, facility, structure, or installation;

III.I.2.b. Install any machine, equipment, or other device;

III.I.2.c. Commence the conduct of any such activity;

III.I.2.d. Commence performance of any combinations thereof; or

III.I.2.e. Commence operations of any of the same that will or do constitute a new stationary source.

III.I.3. Administration

III.I.3.a. General construction permits may be issued, modified, revoked and reissued, or terminated in accordance with the provisions of this regulation.

III.I.3.b. Sources shall submit applications to be covered under the general construction permit on forms provided by the Division.

III.I.3.c. Individual Permit Requirements

III.I.3.c.(i) The Division may require any source authorized by a general construction permit to apply for and obtain an individual permit. Cases where an individual permit may be required include, but are not limited to, the following:

III.I.3.c.(i)(A) A change has occurred in the availability of control technology or practices for the control or abatement of air pollutants applicable to the source; or

III.I.3.c.(i)(B) Circumstances have changed since the time of the request to be covered so that the source is no longer appropriately controlled under the general construction permit.

III.I.3.c.(ii) Any source authorized by a general construction permit may request to be excluded from the coverage of the general construction permit by applying for an individual permit, as provided for under this regulation, Parts A and B.

III.I.3.c.(iii) When the Division issues an individual permit to a source otherwise subject to a general construction permit, the applicability of the general construction permit to the individual permittee is automatically terminated on the effective date of the individual permit.

III.I.3.c.(iv) A source excluded from a general construction permit solely because it already has an individual permit may request that the individual permit be revoked, and that it be covered by the general construction permit. Upon revocation of the individual permit, the general construction permit shall apply to the source.

III.I.3.c.(v) In determining whether an individual permit is required, the Division may consider the compliance history and current compliance status of the source.

III.I.4. The Division shall review the application and certify or deny the request based on criteria specified in the general construction permit established by the Division for that type of source.

III.I.5. General construction permits shall include conditions necessary to ensure the sources will meet all applicable requirements.

III.I.6. General construction permits issued by the Division may include the following requirements, as appropriate and as specified in each permit:

III.I.6.a. An operating and maintenance plan for all control equipment and control practices;

III.I.6.b. A record keeping format for demonstrating compliance;

III.I.6.c. Monitoring methods to assure compliance; and

III.I.6.d. Alternative operating scenarios that include specific monitoring, record keeping, and reporting methods that will assure compliance with the permit conditions.

III.I.7. All general construction permits shall undergo statewide public notice. If a source wants to be covered under a general construction permit, the source must apply within the time period specified in the public notice.

## PART C CONCERNING OPERATING PERMITS

### I. Applicability

The provisions of this Regulation Number 3, Part C shall apply statewide to all sources of air pollutants that are required to obtain an operating permit as specified in Section II. The provisions of this Part C shall also apply, except as otherwise provided herein, to those minor sources of air pollutants that voluntarily choose to obtain an operating permit.

I.A. DEFINITIONS

I.A.1. Affected Source

(acid deposition program) A source of air pollutants that includes one or more fossil fuel fired combustion devices subject to emission reduction requirements or limitations under Title IV of the Federal Act, Code of Federal Regulations Title 40, Part 72, or under the state Act.

I.A.2. Minor Permit Modification

Any revisions to an operating permit issued by the Division that meets the criteria of Sections X. or XI. of this Part C.

I.A.3. Permit Modification

Any revision to an operating permit issued by the Division that cannot be accomplished under the administrative permit amendment procedures set forth in Section III. of Part A of this regulation, or the minor permit modification procedures set forth in Sections X. or XI. of this Part C. A permit modification for purposes of the acid rain portion of a permit shall be governed by regulations promulgated under Title IV of the Federal Act, found at Code of Federal Regulations, Title 40, Part 72.

I.A.4. Permit Shield

Where a source operates in compliance with all operating permit terms and conditions, the source shall be deemed in compliance with the state and Federal Acts where the permit includes all applicable requirements of such acts, specifically states that other identified provisions are not applicable, and states that the permit shield applies. The permit shield does not apply to terms and conditions that become applicable to the source subsequent to permit issuance. The permit shield shall not alter or affect the provisions of Colorado Revised Statutes Sections 25-7-112 or 25-7-113, Section 303 of the Federal Act, the applicable requirements of the acid rain program, consistent with Section 408(a) of the Federal Act, or the ability of the Administrator to obtain information from a source pursuant to Section 114 of the Federal Act; nor shall the permit shield affect the liability of an owner or operator of a source for any violation of applicable requirements prior to or at the time of permit issuance.

I.A.5. Renewal of an Operating Permit

The process by which a permit is reissued at the end of its term.

I.A.6. Section 502(b)(10) Changes

Changes that contravene an express permit term. Such changes do not violate applicable requirements or contravene federally enforceable permit terms and conditions that are monitoring (including test methods), record keeping, reporting, or compliance certification requirements.

I.A.7. Significant Permit Modification

All operating permit modifications that do not qualify as minor permit modifications or as administrative permit amendments. At a minimum, a significant permit modification shall include:

I.A.7.a. Any change that causes a significant increase in the rate of emissions as described by any permit term or condition;

I.A.7.b. Any change that is considered a modification under Title I of the Federal Act;

I.A.7.c. Any change that requires or changes a case-by-case determination of an emission limitation or other standard;

I.A.7.d. Any change that requires or changes a source specific determination for temporary sources of ambient impacts;

I.A.7.e. Any change that requires or changes a visibility or increment analysis;

I.A.7.f. Every significant change in existing monitoring permit terms or conditions; and

I.A.7.g. Every relaxation of reporting or record keeping permit terms or conditions.

I.A.7.h. Every change that seeks to establish or change a permit term or condition for which there is no corresponding underlying applicable requirement and that the source has assumed to avoid an applicable requirement to which the source would otherwise be subject. Such terms and conditions include:

I.A.7.h.(i) A federally enforceable emissions cap assumed to avoid classification as a modification under any provision of Title I of the Federal Act; and

I.A.7.h.(ii) An alternative emissions limit approved pursuant to regulations promulgated under Section 112(i)(5) of the Federal Act

I.A.7.i. The establishment of a Plant-wide Applicability Limitation (PAL) in accordance with Section XVII. of Part D of this regulation.

I.A.7.j. All significant permit modifications shall be processed using the procedures set forth in Part C of Regulation Number 3 for combined Construction/Operating Permit issuance. Such source may choose to obtain a construction permit pursuant to Part B and shall subsequently meet the operating permit requirements of Part C.

## II. General Requirements for Operating Permits

II.A. General Considerations

II.A.1. Except where specifically authorized by the terms of this Regulation Number 3, Part C, no person shall operate any of the following sources without first obtaining an operating permit in accordance with the provisions of this regulation.

II.A.1.a. Any affected source;

II.A.1.b. Any major source; with the exception of those sources that would be major based only on total suspended particulates emissions

II.A.1.c. Any source required to have a permit pursuant to the prevention of significant deterioration program of Part C, Title I, of the Federal Act;

II.A.1.d. Any source required to have a permit pursuant to the program for the attainment and maintenance of national ambient air quality standards or Part D of Title I of the Federal Act; and

II.A.1.e. Any solid waste incineration unit that is a distinct operating unit of any facility that combusts any solid waste material from commercial or industrial establishments or the general public (including single residences, hotels, and motels). Such term does not include: (1) incinerators or other units required to have a permit under United States Code Title, 42, Section 6925 of the Solid Waste Disposal Act; (2) materials recovery facilities (including primary or secondary smelters) which combust waste for the primary purpose of recovering metals; (3) qualifying small power production facilities, as defined in United States Code Title 16, Section 769(17)(C), or qualifying cogeneration facilities, as defined in United States Code Title 16, Section 796(18)(B), of the Federal Power Act, that burn homogenous waste for the production of electric energy or in the case of qualifying cogeneration facilities that burn homogeneous waste for the production of electric energy and steam or forms of useful energy (such as heat) that are used for industrial, commercial, heating, or cooling purposes; or (4) air curtain incinerators provided that such incinerators only burn wood wastes, yard wastes and clean lumber and that such air curtain incinerators comply with any applicable opacity limitations. Operating permits for solid waste incineration units shall be obtained within thirty-six months of promulgation of a new source performance standard applicable to such units, or by November 15, 1994, whichever is later.

II.A.1.f. Any source designated by the Administrator and the Commission as requiring an operating permit.

II.A.1.g. A source is not required to obtain an operating permit solely because it is subject to regulation or requirements pursuant to Section 112(r) of the Federal Act.

II.A.2. Any construction permit that has been issued pursuant to Regulation Number 3, Part B, with respect to a source that is subject to the operating permit requirements of this Part C, shall continue in full force and effect until such time as the operating permit is issued for such source, if the source has filed a timely and complete operating permit application. If a complete operating permit application has been timely filed with the Division by the source in accordance with the provisions of Section III., below, the source will not be subject to an enforcement action for operating the source without an operating permit. No source subject to an operating permit may operate after the time it is required to file a timely and complete application except in compliance with a previously issued operating permit and as set forth in Section II.B., below. A previously issued construction permit shall not constitute a defense for operating a source in violation of the requirement to have an operating permit.

II.A.3. Any orders or decisions of the Division shall be final upon issuance.

II.B. Application Shield

A timely and complete application for an operating permit under the provisions of this Part C shall operate as a defense to an enforcement action for the source's failure to have an operating permit until the Division or the Commission makes a final determination on the permit application. This defense to an enforcement action shall not apply if, subsequent to the completeness determination required by Section IV.B.1. of this Part C, the applicant fails to submit by the deadline specified in writing by the Division any additional information identified as necessary to process the application, or to otherwise supplement its application in accordance with the provisions of Sections IV.B.3. and IV.B.4. of this Part C. This defense to an enforcement action shall not be available to an applicant that files a fraudulent application. Permit expiration terminates the source's right to operate unless a timely and complete renewal application has been submitted to the Division.

II.C. Transfer or assignment of ownership

If transfer or assignment of ownership or operation of an air pollution emission source permitted pursuant to the operating permit requirements of this Part C of Regulation Number 3 is anticipated, the prospective owner or operator shall apply to the Division, on Division supplied administrative permit amendment forms, for reissuance of the existing permit. Part A, Section III. governs the administrative permit amendment procedures required for transfer or assignment of ownership of a source subject to the operating permit requirements. No administrative permit amendment shall be complete until a written agreement containing a specific date for transfer of permit, responsibility, coverage, and liability between the current and new permittee has been submitted to the Division.

II.D. Portable Sources

A portable source that conducts the same or similar type activity at multiple temporary locations throughout the state may be issued a single operating permit under this Part C, provided that the operation involves at least one change in location of the source during the five year permit term. Portable sources must notify the Division at least ten days in advance of each change in location. The owner or operator of a portable source must demonstrate that all applicable requirements will be met at all locations at which the source will operate before an operating permit authorizing operations at the multiple locations will be issued. Sources subject to the acid rain provisions of Title IV of the Federal Act shall not constitute portable sources.

II.E. Insignificant Activities and Exemptions from Operating Permit Requirements

Sources that are otherwise required to obtain an operating permit are not required to include insignificant activities from the following list in their operating permit applications, except as otherwise provided below.

None of the exemptions listed below, including emission de minimis levels, shall apply if by taking such exemption a source would avoid any specific federal or state applicable requirement, including, but not limited to, New Source Performance Standards, Regulation Number 7, Prevention of Significant Deterioration (Section VI., Part D of this Regulation Number 3), nonattainment New Source Review requirements (Section V. Part D of this Regulation Number 3), Title III, National Emission Standards for Hazardous Air Pollutants, Title V, and Colorado Maximum Achievable Control Technology or Generally Available Control Technology . (If the potential to emit, taking into account full design rate and continuous operation, triggers Prevention of Significant Deterioration or New Source Review requirements, the source must submit an Air Pollutant Emission Notice and apply for the appropriate permit, or must apply for a permit to limit the physical or operational capacity of the source such that the source is not considered to be a major source as defined in Section I.B.25. of Part A of this regulation.).

Sources otherwise required to obtain an operating permit are required to include a list of insignificant activities in their permit applications if the insignificant activities are listed in Sections II.E.1. and II.E.2., or marked with an asterisk in Section II.E.3. The asterisk denotes an insignificant activity source category based on the size of the activity, emissions levels from the activity or the production rate of the activity. The owner or operator of individual emission points marked with an asterisk in Section II.E.3., below, must maintain sufficient record keeping verifying that the exemption applies. Such records shall be made available for Division review upon request.

The following sources are exempt from the requirement to obtain an operating permit pursuant to this Part C:

II.E.1. Sources subject to regulation or requirements pertaining to standards of performance for new residential wood heaters pursuant to Regulation Number 6; or

II.E.2. Sources subject to regulation or requirements pertaining to national emissions standards for hazardous air pollutants for asbestos in the course of demolition and renovation pursuant to Regulation Number 8.

II.E.3. Certain categories of sources and activities which are considered to be insignificant contributors to air pollution as listed below. A source solely comprised of one or more of these activities are not required to obtain an operating permit pursuant to this regulation, unless the source's emissions trigger the major source threshold as defined in Section I.B.25. of Part A of this Regulation Number 3 (definition of major source):

II.E.3.a. *Individual emission points in nonattainment areas having uncontrolled actual emissions of any criteria pollutant (as defined in Section I.B.17. of Part A of this Regulation Number 3) of less than one ton per year, and individual emission points in attainment or attainment/maintenance areas having uncontrolled actual emissions of any criteria pollutant of less than two tons per year, and each individual emission point with uncontrolled actual emissions of lead less than one hundred pounds per year, regardless of where the source is located.

II.E.3.b. Individual emission points of non criteria reportable pollutants having uncontrolled actual emissions less than the de minimis levels as determined following the procedures set forth in Appendix A.

II.E.3.c. Air conditioning or ventilating systems not designed to remove air pollutants generated by or released from other processes or equipment.

II.E.3.d. Fireplaces used for recreational purposes, inside or outside.

II.E.3.e. Fires and equipment used for noncommercial cooking of food for human consumption, or cooking of food for human consumption at commercial food service establishments, except for char broilers and wood fired equipment (but not including campfires) in PM10 nonattainment areas. Charbroiler shall mean a cooking device in a commercial food service establishment, either gas fired or using charcoal or other fuel, upon which grease drips down upon an open flame, charcoal or embers.

II.E.3.f. Flares used to indicate danger to the public.

II.E.3.g. Agriculture operations such as farming, cultivating and harvesting, seasonal crop drying, grain handling operations that are below New Source Performance Standards de minimis levels (including milling and grain elevator operations), and animal feeding operations that are not housed commercial swine feeding facilities as defined in Regulation Number 2, Part B. This exemption does not apply to an agricultural operation that: (1) is a major source (Regulation Number 3, Part A, Section I.B.25.); (2) meets or exceeds the storage capacity thresholds of a federal New Source Performance Standards (Regulation Number 6, Part A); or (3) participates in the early reduction program of the Federal Act, Section 112. Ancillary operations such as fueling stations located at farms or ranches are not exempt from Air Pollutant Emission Notice and permit requirements unless otherwise below the de minimis emission levels contained in this regulation, and are not exempt from other applicable regulations promulgated by the Commission.

II.E.3.h. Emissions from, or construction, or alteration of residential structures, including all buildings or other structures used primarily as a place of residence, and including home heating devices.

II.E.3.i. Research laboratories

II.E.3.i.(i) Noncommercial (in house) experimental and analytical laboratory equipment that is bench scale in nature including quality control/quality assurance laboratories, process support laboratories, environmental laboratories supporting a manufacturing or industrial facility, and research and development laboratories.

II.E.3.i.(ii) *Research and development activities that are of a small pilot scale and that process less than ten thousand pounds of test material per year;

II.E.3.i.(iii) *Small pilot scale research and development projects less than six months in duration with controlled actual emissions less than five hundred pounds of any criteria pollutant or ten pounds of any non criteria reportable pollutant.

II.E.3.j. *Disturbance of surface areas for purposes of land development, that do not exceed twenty-five contiguous acres and that do not exceed six months in duration. (This does not include mining operations or disturbance of contaminated soil).

II.E.3.k. *Each individual piece of fuel burning equipment, other than smokehouse generators and internal combustion engines, that uses gaseous fuel, and that has a design rate less than or equal to five million British thermal units per hour. (See definition of fuel burning equipment in the Common Provisions Regulation).

II.E.3.l. Internal combustion engines powering portable drilling rigs.

II.E.3.m. *Petroleum industry flares, not associated with refineries, combusting natural gas containing no hydrogen sulfide except in trace amounts (less than five hundred parts per million weight), approved by the Colorado Oil and Gas Conservation Commission and having uncontrolled emissions of any pollutant of less than five tons per year.

II.E.3.n. *Chemical storage tanks or containers that hold less than five hundred gallons, that have an annual average throughput less than twenty-five gallons per day, and are not associated with either oil and gas production wastewater or commercial facilities that accept oil production wastewater for processing.

II.E.3.o. Unpaved public and private roadways, except for haul roads located within a stationary source site boundary.

II.E.3.p. Sanding of streets and roads to abate traffic hazards caused by ice and snow.

II.E.3.q. Open burning activities, except that all reporting and permitting requirements that apply to such operations must be followed (see Regulation Number 9).

II.E.3.r. Brazing, soldering, or welding operations that use lead based compounds. All welding that occurs strictly for maintenance purposes is exempt.

II.E.3.s. Street and parking lot striping.

II.E.3.t. Battery recharging areas.

II.E.3.u. Aerosol can usage.

II.E.3.v. Sawing operations that are ancillary to facility operations and are not part of the production process.

II.E.3.w. The process of demolition and re-bricking of furnaces and kilns. This does not include subsequent operation of such furnaces or kilns.

II.E.3.x. Road and lot paving operations at commercial and industrial facilities, except that asphalt and cement batch plants require Air Pollutant Emission Notices and permits, unless exempt under some other section.

II.E.3.y. Adhesive use that is not related to production.

II.E.3.z. Fire training activities.

II.E.3.aa. Caulking operations that are not part of a production process.

II.E.3.bb. *Landscaping and site housekeeping devices equal to or less than ten horsepower in size (lawnmowers, trimmers, snow blowers, etc.).

II.E.3.cc. Fugitive emissions from landscaping activities (e.g., weeding, sweeping).

II.E.3.dd. Landscaping use of pesticides, fumigants, and herbicides.

II.E.3.ee. *Crude oil loading truck equipment at exploration and production sites where the loading rate does not exceed 10,000 gallons of crude oil per day averaged on an annual basis. Condensate truck loading equipment at exploration and production sites that splash fill less than 6750 barrels of condensate per year or that submerge fill less than 16308 barrels of condensate per year.

II.E.3.ff. Emergency events such as accidental fires.

II.E.3.gg. Smoking rooms and areas.

II.E.3.hh. Plastic pipe welding.

II.E.3.ii. Vacuum cleaning systems used exclusively for industrial, commercial, or residential housekeeping purposes.

II.E.3.jj. Beauty salons.

II.E.3.kk. Operations involving acetylene, butane, propane and other flame cutting torches.

II.E.3.ll. Pharmacies.

II.E.3.mm. *Chemical storage areas where chemicals are stored in closed containers, and where total storage capacity does not exceed five thousand gallons. This exemption applies solely to storage of such chemicals. This exemption does not apply to transfer of chemicals from, to, or between such containers.

II.E.3.nn. Architectural painting, roof coating material and associated surface preparation (except for sandblasting and except for volatile organic compound emissions, associated with surface preparation, above Air Pollutant Emission Notice de minimis levels) for maintenance purposes at industrial or commercial facilities.

II.E.3.oo. Emissions of air pollutants that are not criteria or non-criteria reportable pollutants (see Sections I.B.17. and I.B.30. of Part A of this regulation). These emissions include methane, ethane and carbon dioxide.

II.E.3.pp. Janitorial activities and products.

II.E.3.qq. Grounds keeping activities and products.

II.E.3.rr. Sources of odorous emissions that do not utilize emission control equipment for control of odorous emissions. This exemption applies to the odor emissions only. All other emissions are subject to other exemptions set forth in this regulation. This exemption does not exempt any source from the requirements of Regulation Number 2.

II.E.3.ss. Truck and car wash units.

II.E.3.tt. Office emissions, including cleaning, copying, and restrooms.

II.E.3.uu. *Oil production wastewater (produced water tanks), containing less than one percent by volume annual average crude oil, except for commercial facilities that accept oil production wastewater for processing.

II.E.3.vv. Electrically operated curing ovens, drying ovens and similar activities, articles, equipment, or appurtenances. This exemption applies to the ovens only, and not to the items being dried in the ovens.

II.E.3.ww. Equipment used exclusively for portable steam cleaning.

II.E.3.xx. Blast-cleaning equipment using a suspension of abrasive in water and any exhaust system or collector serving them exclusively.

II.E.3.yy. Commercial laundries (except dry cleaners) that do not burn liquid or solid fuel.

II.E.3.zz. Storage of butane, propane, or liquefied petroleum gas in a vessel with a capacity of less than sixty thousand gallons, provided the requirements of Regulation Number 7, Section IV. are met, where applicable.

II.E.3.aaa. Storage tanks of capacity less than forty thousand gallons of lubricating oils or waste lubricating oils.

II.E.3.bbb. *Venting of compressed natural gas, butane or propane gas cylinders, with a capacity of one gallon or less.

II.E.3.ccc. *Fuel storage and dispensing equipment in ozone attainment areas operated solely for company-owned vehicles where the daily fuel throughput is no more than four hundred gallons per day, averaged annually. Sources in an ozone attainment/maintenance area must utilize Stage 1 vapor recovery on all tanks greater than five hundred and fifty gallons capacity, as required by Regulation Number 7, in order to take this exemption.

II.E.3.ddd. Exemption Repealed.

II.E.3.eee. Indirect sources are exempt until a (permit) regulation specific to indirect sources is promulgated by the Commission.

II.E.3.fff. *Storage tanks meeting all of the following criteria:

II.E.3.fff.(i) Annual throughput is less than four hundred thousand gallons; and

II.E.3.fff.(ii) The liquid stored is one of the following:

II.E.3.fff.(ii)(A) Diesel fuels 1-D, 2-D, or 4-6;

II.E.3.fff.(ii)(B) Fuel oils #1 - #6;

II.E.3.fff.(ii)(C) As turbine fuels 1 - GT through 4 - GT;

II.E.3.fff.(ii)(D) An oil/water mixture with a vapor pressure less than or equal to that of diesel fuel (Reid vapor pressure of .025 psia).

II.E.3.ggg. Each individual piece of fuel burning equipment that uses gaseous fuel, and that has a design rate less than or equal to ten million British thermal units per hour, and that is used solely for heating buildings for personal comfort.

II.E.3.hhh. Natural gas vehicle fleet fueling facilities.

II.E.3.iii. Electric motors driving equipment at non-commercial machining shops.

II.E.3.jjj. Recreational swimming pools.

II.E.3.kkk. Forklifts.

II.E.3.lll. Handling equipment and associated activities for glass that is destined for recycling.

II.E.3.mmm. Containers, reservoirs, or tanks used exclusively for dipping operations, that contain no organic solvents, for coating objects with oils, waxes, greases, or natural or synthetic resins.

II.E.3.nnn. Stationary Internal Combustion Engines that:

II. E.3.nnn.(i) Are power portable drilling rigs; or

II. E.3.nnn.(ii) Are emergency power generators that operate no more than two hundred fifty hours per year; or

II. E.3.nnn.(iii) Have uncontrolled actual emissions less than five tons per year or manufacturer's site-rated horsepower of less than fifty

II.E.3.ooo. The collection, transmission, liquid treatment, and solids treatment processes at domestic wastewater treatment works, or treatment facilities that treat only domestic type wastewater, except for combustion processes.

II.E.3.ppp. Gasoline stations located in ozone attainment areas.

II.E.3.qqq. *Surface mining activities that mine seventy thousand tons or fewer of product material per year. A fugitive dust control plan is required for such sources. Crushers, screens and other processing equipment activities are not included in this exemption.

II.E.3.rrr. Composting piles, however, all odor requirements of Regulation Number 2 must be met.

II.E.3.sss. Fugitive emissions of hazardous air pollutants that are natural constituents of native soils and rock (not added or concentrated by chemical or mechanical processes) from underground mines or surface mines unless such source is a major source of hazardous air pollutants under Part C of this Regulation Number 3.

II.E.3.ttt. The use of pesticides, fumigants, and herbicides when used in accordance with requirements established under the federal Insecticide, Fungicide and Rodenticide Act as established by the U.S. EPA (United States Code Title 7, Section 136 et seq.).

II.E.3.uuu. Ventilation of emissions from mobile sources operating within a tunnel, garage, or building that are not operating for transportation purposes and are subject to stationary source requirements,.

II.E.3.vvv. Non-asbestos demolition.

II.E.3.www. Sandblast equipment when the blast media is recycled and the blasted material are collected.

II.E.3.xxx. Stationary internal combustion engines:

II.E.3.xxx.(i) *Less than or equal to 175 horsepower which operate less than 1,450 hours per year.

II.E.3.xxx.(ii) *Greater than 175 horsepower and less than or equal to 300 horsepower which operate less than 850 hours per year.

II.E.3.xxx.(iii) *Greater than 300 horsepower and less than or equal to 750 horsepower which operate less than 340 hours per year.

II.E.3.yyy. Surface water storage impoundment of non-potable water and storm water evaporation ponds, with the exceptions of impoundment of oil and gas production wastewater (including produced water tanks) containing equal to or more than one percent by volume crude oil on an annual average and commercial facilities that accept oil and gas production wastewater for processing.

II.E.3.zzz. Non-potable water pipeline vents.

II.E.3.aaaa. Steam vents and safety release valves.

II.E.3.bbbb. Exemption Repealed.

II.E.3.cccc. Seal and lubricating oil systems for steam turbine electric generators.

II.E.3.dddd. Venting of natural gas lines for safety purposes.

II.E.3.eeee. Chemical storage tanks

II.E.3.eeee.(i) *Sulfuric acid storage tanks not to exceed ten thousand five hundred gallons capacity.

II.E.3.eeee.(ii) *Sodium hydroxide storage tanks.

II.E.3.ffff. Wet screening operations notwithstanding the applicability of the New Source Performance Standards included in the Code of Federal Regulations, Title 40, Part 60, Subpart OOO.

II.E.3.gggg. *Any condensate storage tank with a production rate of 730 barrels per year or less or condensate storage tanks that are manifold together with a production rate of 730 barrels per year or less that are owned and operated by the same person, and are located at exploration and production sites.

II.F. Sources that are not required by this Part C to obtain an operating permit may elect to apply for, and may be issued, an operating permit. Any such permit issued must contain terms and conditions sufficient to satisfy the requirements of this regulation.

II.G. All federally enforceable terms and conditions in an operating permit, including any provisions designed to limit a source's potential to emit, are enforceable by the Administrator, as well as citizens pursuant to United States Code Title 42, Section 7604.

**III. Operating Permit Application Requirements**

III.A. Option for pre application meeting

Prior to submitting an application for a permit an applicant may request and, if so requested, the Division shall grant, a pre application meeting with the applicant. At such meeting, the Division shall advise the applicant of the applicable permit requirements, including the information, plans, specifications and the data required to be furnished with the permit application, based on the best information available from the applicant at the time. Failure of the Division to identify all requirements and information does not exempt the source from compliance with applicable requirements or these regulations.

III.B. Application for operating permit and combined construction/operating permit applications

III.B.1. An application for an operating permit shall be prepared on forms supplied by the Division that meet all the requirements of the Federal Act. Applicants shall submit sufficient copies of their applications for provision of copies to the Administrator, affected states and county clerks as required by Sections V.B.5., VI., and IX. of this Part C.

III.B.2. Each source required to obtain an operating permit pursuant to Section III. of this Part C, for the first time, shall submit an application for such a permit no later than twelve months after the source becomes subject to the operating permit requirement. A source that becomes subject to the operating permit program by operation of law, such as the adoption of new legal requirements, shall submit an application for an operating permit within twelve months of the effective date of such new legal requirements unless otherwise specified by the requirements. A new source or an existing source that modifies in a way that renders it newly subject to the operating permit requirements, shall submit a complete application for an operating permit within twelve months of commencing operation, except as otherwise provided herein. Modifications made to a source with an operating permit, through a permit issued under Part B of this regulation shall apply for a modification to their operating permit within twelve months of startup. A new source (including any significant modification), shall meet the applicable requirements of Part B.

III.B.3. Reserved.

III.B.4. Reserved.

III.B.5. All other major sources existing on January 1, 1995 shall submit their operating permit applications unless otherwise notified by the Division.

III.B.6. Each source subject to an operating permit shall submit an application for renewal of the operating permit at least twelve months, but not more than eighteen months, prior to the expiration of the operating permit. All of the provisions governing the application for and issuance of operating permits are applicable to applications for renewal of operating permits, except that an application for permit renewal may address only those portions of the permit that require revision, supplementing, or deletion, incorporating the remaining permit terms by reference from the previous permit. A copy of any materials incorporated by reference must be included with the application. The Division may choose to issue a draft renewal or proposed renewal permit specifying only those portions that will be revised, supplemented, or deleted, incorporating the remaining permit terms by reference. All requirements for compliance plans, compliance schedules and compliance certifications found in Sections III.B.7., III.B.8., and III.C.8. through III.C.13. of this Part C, are applicable to the entire operating permit upon renewal.

III.B.7. A source required to obtain a construction permit pursuant to Part B of this Regulation Number 3 may submit an application for a combined construction permit and operating permit on a standard application form supplied by the Division prior to commencing construction, modification, installation or commencement of any activities or operations for which a construction permit is required pursuant to Part B. In accordance with the provisions of Part B, a source applying for a combined construction/operating permit cannot construct before issuance of a permit.

III.B.8. Applications shall be signed by a responsible official who shall also sign the compliance certification on the application. The compliance certification shall include: (a) a certification of compliance with all applicable requirements; (b) a statement of methods used for determining compliance, including a description of monitoring, record keeping, and reporting requirements and test methods; (c) a schedule for submission of compliance certifications during the permit term not less than annually, or more frequently as specified by the terms and conditions of the permit; (d) a statement indicating the source's compliance status with any applicable compliance assurance monitoring and compliance certification requirements; (e) if applicable to a source, a statement indicating the source has properly registered its risk management plan required pursuant to Section 112(r) of the Federal Act. Compliance certifications for state only conditions shall be separate from compliance certifications required under the Federal Act, and shall only be required for sources of such state only conditions seeking the operational flexibility provisions of Sections X., XI., and XII. of this Part C. Sources seeking protection under the terms of the permit shield for such state only conditions, or sources of state only conditions are otherwise required to obtain an operating permit pursuant to the state Act.

III.B.9. Each application form, report and compliance certification submitted pursuant to this regulation shall contain a certification by a responsible official of the truth, accuracy and completeness of such form, report or certification stating that, based on information and belief formed after reasonable inquiry, the statements and information in the document are true, accurate and complete.

III.C. Complete applications

The applicant shall furnish all information and data required by the Division to evaluate the permit application and to make its preliminary analysis in accordance with Section IV. of this Part C including, but not limited to:

III.C.1. Identifying information, including company name and address (or plant name and address if different from the company name), owner's name and agent, and telephone number and name of plant site manager/contact;

III.C.2. A description of the source's processes and products (by standard industrial classification code) including any associated with alternate scenarios identified by the source;

III.C.3. The following emission-related information:

III.C.3.a. All emissions of pollutants for which the source is major, and all emissions of regulated air pollutants. A permit application shall describe all emissions of regulated air pollutants emitted from any emissions unit, except where such units are exempted under Section II.E. of this Part C, and all additional information related to the emissions of pollutants sufficient to verify which requirements are applicable to the source and other information necessary to collect any permit fees owed pursuant to Section VI. of Part A of this regulation;

III.C.3.b. Identification and description of all points of emissions described in Section III.C.3.a., above, in sufficient detail to establish the basis for fees and applicability of requirements of the Federal Act;

III.C.3.c. Emissions rate in tons per year and in such terms as are necessary to establish compliance consistent with the applicable standard reference test method;

III.C.3.d. The following information to the extent it is needed to determine or regulate emissions: fuels, fuel use, raw materials, production rates, and operating schedules;

III.C.3.e. Identification and description of air pollution control equipment and compliance monitoring devices or activities;

III.C.3.f. Limitations on source operation affecting emissions or any work practice standards, where applicable, for all regulated air pollutants at the source;

III.C.3.g. Other information required by any applicable requirement, including information related to stack height limitations developed pursuant to United States Code Title 42, Section 7423 (Part A, Section VIII. of this Regulation Number 3); and

III.C.3.h. Calculations on which the information required in Sections III.C.3.a. through III.C.3.g. are based.

III.C.4. The following air pollution control requirements:

III.C.4.a. Citation and description of all applicable requirements, and

III.C.4.b. Description of, or reference to, any applicable test method for determining compliance with each applicable requirement.

III.C.5. Other specific information that may be necessary to implement and enforce other applicable requirements of the Federal Act or of this Section III., or to determine the applicability of such requirements.

III.C.6. An explanation of any proposed exemptions from otherwise applicable requirements.

III.C.7. Additional information as determined to be necessary by the Division to define alternative operating scenarios identified by the source pursuant to Section IV.A. of Part A of this regulation, or to define permit terms and conditions implementing Section XII. of this Part C.

III.C.8. A compliance plan which contains: (a) a description of the compliance status of the source with respect to all applicable requirements; (b) for applicable requirements with which the source is in compliance, a statement that the source will continue to comply with such requirements; (c) for applicable requirements that will become effective during the permit term, a statement that the source will meet the requirements on a timely basis; and (d) for requirements for which the source is not anticipated to be in compliance at the time of permit issuance, a narrative description of how the source will achieve compliance with such requirements.

III.C.9. A compliance schedule which contains: (a) for applicable requirements with which the source is in compliance, a statement that the source will continue to comply with such requirements; or (b) for applicable requirements that will become effective during the permit term, a statement that the source will meet the requirements on a timely basis. A statement that the source will meet in a timely manner applicable requirements that become effective during the permit term shall satisfy the provision, unless a more detailed schedule is expressly required by the applicable requirement; and (c) a schedule of compliance for sources that are not anticipated to be in compliance at the time of permit issuance. This schedule shall include a schedule of enforceable remedial milestones, leading to compliance with any applicable requirements for which the source will be in noncompliance at the time of permit issuance. This compliance schedule shall be at least as stringent as that contained in any judicial consent decree or administrative order to which the source is subject. Any such schedule of compliance shall be supplemental to, and shall not sanction noncompliance with, the applicable requirements on which it is based.

III.C.10. A schedule for submission of progress reports no less frequently than every six months for sources required having a schedule of compliance to remedy a violation.

III.C.11. The compliance plan content requirements specified in this section shall apply and be included in the acid rain portion of a compliance plan for an affected source, except as specifically superseded by regulations promulgated under Title IV of the Federal Act, Code of Federal Regulations Title 40, Part 72, with regard to the schedule and method(s) the source will use to achieve compliance with the acid rain emissions limitations.

III.C.12. Data necessary to allow the Division to determine whether the source complies with:

III.C.12.a. All applicable emission control regulations;

III.C.12.b. Applicable regulations for the control of hazardous air pollutants;

III.C.12.c. Requirements of the nonattainment and attainment programs, Sections V. and VI. of Part D of this regulation; and

III.C.12.d. Any applicable ambient air quality standards (for temporary sources and new or modified sources applying for a combined construction/operating permit only). When the data includes modeling, the model used shall be an appropriate one given the topography, meteorology, and other characteristics of the region that the source will impact; and

III.C.12.e. All applicable regulations.

III.C.13. Copies of Air Pollutant Emission Notices on file with the Division indicating production/process rates for which the operating permit is to be evaluated, or, if Air Pollutant Emission Notice(s) have not been previously filed, a new Air Pollutant Emission Notice(s) shall be submitted in accordance with Part A, Section II. The Air Pollutant Emission Notice fee will not be charged for submission of copies of current Air Pollutant Emission Notice(s) previously filed with the Division.

III.D. Operating Permit Renewal

In submitting an application for renewal of an operating permit issued under these regulations, a source may identify terms and conditions in its previous permit that remain unchanged and incorporate by reference those portions of its existing permit and the permit application and any permit amendments or modification applications that describe products, processes, operations, and emissions to which those terms and conditions apply. The source must identify specifically and list which portions of its previous permit and/or applications that are incorporated by reference. In addition, a renewal application must contain:

III.D.1. Information for those products, processes, operations, and emissions, in accordance with the provisions of this Part C, that:

III.D.1.a. Are not addressed in the existing permit;

III.D.1.b. Are subject to applicable requirements that are not addressed in the existing permit; or

III.D.1.c. Are permit terms and conditions that differ from those in the existing permit.

III.D.2. A compliance plan, schedule, and certification requirements for the entire permit in accordance with this Part C.

III.E. A major source may comply with this section through any one of the following methods:

III.E.1. The source may obtain a single permit for all relevant emission points located within a contiguous or adjacent area under common control (whether or not falling under the same two digit standard industrialized code);

III.E.2. The source may obtain separate permits for separate emission points or groups of emission points, or

III.E.3. The Division may issue a permit covering one or more emission points eligible for coverage under a general permit and the source may obtain a separate permit or permits for emission points not eligible for such coverage.

III.F. The acid rain portions of permit applications shall be made on nationally standardized forms pursuant to regulation promulgated by the Administrator at Code of Federal Regulations Title 40, Part 72.

## IV. Processing Of Applications

IV.A. Standards for application determinations

The Division shall evaluate operating permit applications and combined construction/operating permit applications. The evaluation of permit applications shall consider, for the construction permit portion, whether operation of the proposed new source at the date of start-up, and for operating permits whether the permitted emissions, will comply with all applicable emissions control regulations, regulations for the control of hazardous air pollutants, applicable ambient air quality standards and regulations, requirements for the prevention of significant deterioration of air quality that is better than the National Ambient Air Quality Standards, and nonattainment and attainment/maintenance area requirements. The submittal of a complete application shall not affect the requirement that any source have a construction permit pursuant to Part B of this Regulation Number 3, except as otherwise required herein.

IV.B. Completeness determinations

IV.B.1. An application for an operating permit or a combined construction permit/operating permit, will not be deemed to be complete until all information and data required to evaluate the application have been submitted to the Division. Within sixty calendar days after the receipt of an application or any supplemental information requested by the Division, the Division will give notice to the applicant if and in what respect the application is incomplete. If the Division fails to notify an applicant that the application is incomplete within sixty calendar days of receipt of the original application or receipt of the requested supplemental information, the application shall be deemed to have been complete as of the day of receipt by the Division of the application or the last submitted supplemental information, whichever is later, for the purposes specified in Section II.B. of this Part C (concerning the application shield). Nothing herein precludes the Division from requesting further information about the source in order to process the permit application. If the Division concludes that the application is not complete, it shall inform the applicant of the additional information that must be submitted prior to consideration of the application. No completeness determination shall be required for applications for administrative or minor permit modification procedures under Section III. of Part A of this regulation, or Sections X. and XI. of this Part C.

IV.B.2. The Division shall review each application submitted to determine whether it is complete. An application shall be deemed to be complete when it contains the information required by Sections III.B., III.C., and III.D. of this Part C in sufficient detail for the Division to evaluate the subject source and the permit application, to determine all applicable requirements and to calculate all applicable fees.

IV.B.3. A source shall supplement its permit application to correct or update information provided in its initial submission as soon as it becomes aware of any omissions or incorrect information submitted or to address changes made to the source after submission of the application, but prior to public notice as provided in Section VI. of this Part C.

IV.B.4. A source shall supplement its permit application to address any requirements that become applicable to the source after the date the source submitted its application, but prior to issuance of a draft permit.

IV.C. Permit application processing timeframes

For operating permit applications, or for combined construction and operating permit applications, the Division shall approve or disapprove the permit application within eighteen months of receipt of a complete application. Permit processing timeframes for operating permit applications for affected sources under the acid rain provisions shall be governed by Code of Federal Regulations Title 40, Part 72. If a timely and complete application is filed, but the Division fails to issue or deny a renewal operating permit prior to expiration of the operating permit for which a source is seeking renewal, the previously issued operating permit, and all of its terms and conditions, shall not expire until the renewal operating permit is issued and any previously extended permit shield continues in full force and operation.

To the extent feasible, applications shall be acted upon in the order received except that priority shall be given to taking final action on applications for construction or modification under Title I, Parts C and Part D, of the Federal Act. Final action on such applications shall be taken within twelve months following receipt of a complete application.

IV.D. Requests for additional information

If, after an application is deemed complete, the Division determines that additional information is necessary to evaluate or take final action on an application, the Division shall request necessary information in writing and set a reasonable deadline for response. Additional information submitted within the deadline will be evaluated by the Division. If the applicant fails to provide the requested information or does not meet the deadline, the source's ability to operate without a permit shall terminate on the date of the deadline as provided in Section II.B. of this Part C.

**V. Operating Permit Issuance, Renewals And Modifications**

V.A. Except as provided below, the Division shall not issue, reissue or renew an operating permit until the source has obtained a final approval construction permit for all emission units pursuant to Regulation Number 3, Part B, Section III.G. However, nothing in this section shall preclude the Division from issuing, reissuing, or renewing an operating permit if the holder of an initial approval construction permit has not commenced operation of the new construction or modification authorized by that construction permit.

When the source has not demonstrated compliance with the terms of an initial approval construction permit as required pursuant to Regulation Number 3, Part B, Section III.G., or has not obtained a final approval construction permit as required above, the Division may issue, reissue or renew an operating permit under the following circumstances:

V.A.1. If the source has not demonstrated compliance under the provisions of Regulation Number 3, Part B, Section III.G., and the source is not anticipated to be in compliance at the time of the operating permit issuance with any of the terms or conditions of the initial approval construction permit, the operating permit must contain a compliance plan and compliance schedule that meets the requirements of this Part C, Sections III.C.8., III.C.9., and III.C.10., with respect to those permit term(s). In that instance, the deviation reporting required under this Part C, Section V.C.7.b. may, at the Division’s discretion, serve as the demonstration required pursuant to Regulation Number 3, Part B, Section III.G. and no final approval construction permit will be issued; or

V.A.2. If the source has not demonstrated compliance under the provisions of Regulation Number 3, Part B, Section III.G., and the source anticipates being in compliance at the time of the operating permit issuance with all of the terms or conditions of the initial approval construction permit, the Division can elect to allow the initial approval construction permit to continue in full force and effect pursuant Regulation Number 3, Part B, Section III.G.4. In that instance, the first deviation report after permit issuance as required under this Part C, Section V.C.7.b. may, at the Division's discretion, serve as the demonstration required pursuant to Regulation Number 3, Part B, Section III.G., and no final approval construction permit will be issued; or

V.A.3. If the source has demonstrated compliance under the provisions of Regulation Number 3, Part B, Section III.G. but not yet received a final approval construction permit, the Division may, at its discretion, elect to either issue a final approval construction permit or allow the initial approval construction permit to continue in full force and effect. The Division shall provide written notice to the permittee of its election.

V.B. An operating permit, permit modification or permit renewal shall be issued only upon a determination by the Division that the following criteria have been met:

V.B.1. The Division has received a complete application for a permit, permit modification, or permit renewal;

V.B.2. Public comment and hearing requirements, except for modifications qualifying for minor permit modification procedures or administrative permit revisions;

V.B.3. Requirements for notifying and responding to affected states pursuant to Section IX. of this Part C. This section is not applicable to minor sources that voluntarily apply for an operating permit for purposes of Sections X., XI., and XII., unless the source is required to have federally enforceable emissions limitations to be considered a minor source, nor to major sources of Colorado-only Hazardous Air Pollutants subject to the operating permit requirements solely due to state-only conditions under the state Act;

V.B.4. Permit conditions provide for compliance with all applicable requirements and the requirements of this Regulation Number 3; and

V.B.5. The Administrator has received a copy of the proposed permit and has not objected to its issuance within forty-five days of receipt of the proposed permit and all necessary supporting information. This section is not applicable to minor sources that voluntarily apply for an operating permit for purposes of Sections X., XI., and XII., unless the source is required to have federally enforceable emissions limitations to be considered a minor source, nor to major sources of Colorado-only Hazardous Air Pollutants subject to the operating permit requirements solely due to state only conditions under the state Act.

V.B.6. The Administrator's objection to permit issuance shall be based on a determination that the proposed permit will not be in compliance with applicable requirements or requirements of Code of Federal Regulations Title 40, Part 70. Any such objection shall include a statement of the Administrator's reasons for objecting and a description of the terms and conditions that the permit must include to respond to the objection. Failure of the Division to do any of the following shall also constitute grounds for an objection by the Administrator:

V.B.6.a. Failure to comply with the provisions of Section V.F. of this Part C for submission of copies of permit applications, proposed permits, and final permits to the Administrator;

V.B.6.b. Failure to comply with the provisions of Section IX. of this Part C for review by affected states;

V.B.6.c. Failure to submit any information to the Administrator necessary to review adequately the proposed permit; or

V.B.6.d. Failure to comply with the provisions of Section VI. of this Part C for public participation.

V.B.7. If the Division fails, within ninety days after an objection by the Administrator, to revise and submit a proposed permit in response to the objection, the Administrator will issue or deny the permit in accordance with the requirements of the federal program promulgated under Title V of the Federal Act.

V.B.8. The permit applicant has paid all applicable hourly fees as set forth in Part A, Section VI. of this Regulation Number 3.

V.C. An operating permit shall contain, at a minimum, the following:

V.C.1. Emissions limitations and standards, including those operational requirements and limitations that assure compliance with all applicable requirements at the time of permit issuance, including:

V.C.1.a. The permit shall specify and reference the origin of and authority for each term and condition, and identify any difference in form as compared to the applicable requirement upon which the term or condition is based; and

V.C.1.b. The permit shall state that, where an applicable requirement of the Federal Act is more stringent than an applicable requirement of regulations promulgated under Title IV of the Federal Act, Code of Federal Regulations Title 40, Part 72, both provisions shall be incorporated into the permit and shall be federally enforceable; and

V.C.1.c. If allowed by the state implementation plan, an alternative emissions limitation that is at least as stringent as an applicable requirement may be substituted for an applicable requirement as a permit term or condition, so long as the permit containing such equivalency determination contains provisions to ensure that any resulting emissions limitation is quantifiable, accountable, enforceable and based on replicable procedures.

V.C.2. The permit term shall be five years.

V.C.3. The effective date and termination date of the permit shall be specifically identified in the permit.

V.C.4. A statement of all monitoring and related record keeping and reporting requirements shall be specifically identified in the permit.

V.C.5. Each permit shall contain the following requirements with respect to monitoring:

V.C.5.a. All emissions monitoring and analysis procedures or test methods required under the applicable requirements, including any required procedures and methods for compliance assurance monitoring and compliance certification requirements;

V.C.5.b. Where the applicable requirement does not require periodic testing or instrumental or non-instrumental monitoring, periodic monitoring, or record keeping, sufficient to yield reliable data for the relevant time period that are representative of the source's compliance with the permit as required to be reported pursuant to Section V.C.16.e. of this Part C. Such monitoring requirements shall assure use of terms, test methods, units, averaging periods, and other statistical conventions consistent with the applicable requirements.

V.C.5.c. As necessary, requirements concerning the use, maintenance and, where appropriate, installation of monitoring equipment or methods.

V.C.6. Each permit shall incorporate all applicable record keeping requirements and require, where applicable, the following:

V.C.6.a. Records of required monitoring information, which includes the following:

V.C.6.a.(i) Date, place, as defined in the permit, and time of sampling or measurements;

V.C.6.a.(ii) Date(s) on which analyses were performed;

V.C.6.a.(iii) The company or entity that performed the analysis;

V.C.6.a.(iv) The analytical techniques or methods used;

V.C.6.a.(v) The results of such analysis; and

V.C.6.a.(vi) The operating conditions as existing at the time of sampling or measurement.

V.C.6.b. The retention of records of all required monitoring data and support information for a period of at least five years from the date of the monitoring sample, measurement, report or application. Support information, for this purpose, includes all calibration and maintenance records and all original strip chart recordings for continuous monitoring instrumentation, and copies of all reports required by the permit. The applicant may, with the Division's approval, maintain any of the above records in a computerized form. Sources must retain records of all required monitoring data and support information for the most recent twelve month period, as well as compliance certifications for the past five years on site at all times. A source shall make available for Division review all other records of required monitoring data and support information required to be retained by a source upon forty-eight hours advance notice by the Division.

V.C.6.c. A permittee may request confidential treatment for information in any report submitted under this section pursuant to the limitations and procedures set forth in Section VII. of Part A of this Regulation Number 3.

V.C.7. Each permit shall incorporate all applicable reporting requirements, and shall require the following:

V.C.7.a. Submittal of all reports of any required monitoring at least every six months except as otherwise required on a more frequent basis pursuant to compliance assurance monitoring rules or other applicable requirements. The Division may approve alternative reporting formats and schedules proposed by an applicant consistent with the requirements of this section, allowing for coordination with other reporting requirements for that source. All instances of deviations from any permit requirements must be clearly identified in such reports. All required reports must be certified by a responsible official consistent with Section III.B.8. of this Part C;

V.C.7.b. Prompt reporting of deviations from permit requirements, including those attributable to upset conditions as defined in the permit, the probable cause of such deviations, and any corrective actions or preventive measures taken. Each permit shall contain a definition of prompt reporting in relation to the degree and type of deviation likely to occur and the applicable requirements. Generally "prompt" reporting shall entail reporting as required in Section V.C.7.a., above, requiring submission of reports of deviations from permit requirements at least every six months, except as otherwise specified by the Division in the permit. Prompt reporting, for this purpose, does not constitute an exception to the requirements of Section VII. relating to reporting of emergency events for the purpose of avoiding enforcement actions.

V.C.8. A permit condition prohibiting emissions exceeding any allowances that the source lawfully holds under Title IV of the Federal Act or the regulations promulgated there under at Code of Federal Regulations Title 40, Part 72.

V.C.9. State only permit terms and conditions shall be listed separately on the operating permit. All procedural requirements of this Part C may apply to such state only conditions, except as otherwise required by the state Act, in order for sources to obtain the permit shield and all operational flexibility provisions. The permit shall also contain a specific designation as not being federally enforceable any state only terms and conditions included in the permit that are not required under the Federal Act or under any of its applicable requirements. A source may choose to obtain a separate construction permit pursuant to Part B for such state only requirements, except as otherwise required under the state Act;

V.C.10. A severability clause that demands the continued validity of the various permit requirements in the event of a challenge to any portion of the permit;

V.C.11. Provisions stating the following permit terms and conditions:

V.C.11.a. The permittee must comply with all conditions of the permit issued under this Part C. Any permit noncompliance relating to federally enforceable terms or conditions constitutes a violation of the Federal Act, as well as the state Act and this regulation. Any permit noncompliance relating to state only terms or conditions constitutes a violation of the state Act and this regulation, shall be enforceable pursuant to state law, and shall not be enforceable by citizens under Section 304 of the Federal Act. Any such violation of the Federal Act, the state Act or regulations implementing either statute is grounds for enforcement action, for permit termination, revocation and reissuance or modification or for denial of a permit renewal application.

V.C.11.b. It shall not be a defense for a permittee in an enforcement action or a consideration in favor of a permittee in a permit termination, revocation or modification action or action denying a permit renewal application that it would have been necessary to halt or reduce the permitted activity in order to maintain compliance with the conditions of the permit;

V.C.11.c. The permit may be modified, revoked, reopened, and reissued, or terminated for cause. The filing of any request by the permittee for a permit modification, revocation and reissuance, or termination, or any notification of planned changes or anticipated noncompliance does not stay any permit condition, except as provided in Sections X. and XI. of this Part C;

V.C.11.d. The permit does not convey any property rights of any sort, or any exclusive privilege;

V.C.11.e. The permittee shall furnish to the Division, within a reasonable time specified by the Division, any information that the Division may request in writing to determine whether cause exists for modifying, revoking and reissuing, or terminating the permit or to determine compliance with the permit. Upon request, the permittee shall also furnish to the Division copies of records required to be kept by the permittee, including information claimed to be confidential. Any information subject to a claim of confidentiality shall be specifically identified and submitted separately from information not subject to the claim;

V.C.12. A requirement that the permittee shall pay to the Division all applicable fees required by the state Act and regulations.

V.C.13. A provision that no permit revision shall be required under any approved economic incentives, marketable permits, emissions trading and other similar programs or processes for changes that are specifically provided for in the permit;

V.C.14. Terms and conditions for reasonably anticipated operating scenarios identified by the source in its application for a permit and approved by the Division, in accordance with Section IV.A. of Part A of this regulation.

V.C.15. Terms and conditions, if the permit applicant requests them, for the trading of emissions increases and decreases in the permitted facility, in accordance with Section IV.B. of Part A.

V.C.16. The following elements with respect to compliance:

V.C.16.a. Consistent with Sections III.B.7., III.B.8., III.C.8. through III.C.13., and V.C.4. through V.C.7. of this Part C, compliance, certification, testing, monitoring, reporting, and record keeping requirements sufficient to assure compliance with the terms and conditions of the permit. Any document (including reports) required by an operating permit shall contain a certification by a responsible official that meets the requirements of Section III.B.8. of this Part C;

V.C.16.b. Inspection and entry requirements that require, upon presentation of credentials and other documents as may be required by law, the permittee shall allow the Division or any authorized representative to perform the following:

V.C.16.b.(i) Enter upon the permittees premises where an operating permit source is located, or emissions-related activity is conducted, or where records must be kept under the terms of the permit;

V.C.16.b.(ii) Have access to, and copy, at reasonable times, any records that must be kept under the conditions of the permit;

V.C.16.b.(iii) Inspect at reasonable times any facilities, equipment (including monitoring and air pollution control equipment), practices, or operations regulated or required under the permit. The permittee shall provide, as part of its permit application, a list of any specialized safety equipment which may be necessary for use by an inspector; and

V.C.16.b.(iv) Any sampling or monitoring of substances or parameters at reasonable times for the purpose of assuring compliance with the permit or applicable requirements;

V.C.16.c. A schedule of compliance consistent with Section III.C. of this Part C;

V.C.16.d. Progress reports consistent with an applicable schedule of compliance and Section III.C. of this Part C, to be submitted at least semiannually or at a more frequent period if so specified in the applicable requirement or by the Division. Such progress reports shall contain the following:

V.C.16.d.(i) Dates for achieving the activities, milestones, or compliance required in the schedule for compliance, and dates when such activities, milestones, or compliance were achieved; and

V.C.16.d.(ii) An explanation of why any dates in the schedule of compliance were not or will not be met, and any preventive or corrective measures adopted.

V.C.16.e. Requirements for compliance certification with terms and conditions contained in the permit, including emission limitations, standards, or work practices. Permits shall include each of the following:

V.C.16.e.(i) The frequency (which shall not be less than annually or such more frequent periods as specified in the applicable requirement or by the Division) of submission of compliance certifications;

V.C.16.e.(ii) In accordance with Sections V.C.4. through V.C.7. of this Part C, a means of monitoring the compliance of the source with its emissions limitations, standards and work practices;

V.C.16.e.(iii) A requirement that the compliance certification include the following:

V.C.16.e.(iii)(A) The identification of each permit term and condition that is the basis of the certification;

V.C.16.e.(iii)(B) The compliance status;

V.C.16.e.(iii)(C) Whether compliance was continuous or intermittent;

V.C.16.e.(iii)(D) The method(s) used for determining the compliance status of the source, currently and over the reporting period, consistent with Sections V.C.4. through V.C.7. of this Part C; and whether the data collection using the methods referenced for compliance certification provide continuous or intermittent data; and

V.C.16.e.(iii)(E) Such other facts as the Division may require to determine the compliance status of the source.

V.C.16.e.(iv) A requirement that all compliance certifications shall be submitted to the Administrator as well as to the Division. This requirement shall not apply to sources subject to the operating permit requirements solely due to state only conditions pursuant to the state Act;

V.C.16.e.(v) Any additional requirements for compliance assurance monitoring and compliance certification;

V.C.16.e.(vi) Such other provisions as the Division may require.

V.C.17. If a source is required to develop and register a risk management plan pursuant to Section 112(r) of the Federal Act, the permit shall only refer to such plan and state the source's compliance with such registration requirement. The content of the risk management plan will not be incorporated as a permit term.

V.D. The permit shield shall extend to applicable requirements that are included and specifically identified in the permit. Upon request, the Division shall include in the permit a determination identifying specific requirements that do not apply to the source. The source shall specify in its permit application for such a determination the requirements as to which the determination is requested. The permit shall state that the permit shield applies to any requirements so identified. A request for a determination to extend the shield to requirements deemed applicable to the source may be made either in the original permit application or in a subsequent application for a permit modification.

V.E. If the Division denies a permit, imposes conditions on a permit that are contested by the applicant, revokes a permit, or requires a permit from a source that may qualify for an exemption, the applicant or owner or operator of the source may request a hearing before the Commission in accordance with the Commission’s Procedures for Adjudications. The request for a hearing must be filed with the Commission within thirty days after the issuance of the permit, denial or revocation. The hearing shall be held in accordance with Colorado Revised Statute Sections 25-7-119 and 24-4-105 and the Commission’s Procedures for Adjudications.

V.F. The Division shall submit to the Administrator a copy of each permit application (including any application for permit modification), each proposed permit, and each final operating permit.

## VI. Public Participation Requirements

VI.A. Except for modifications qualifying for administrative permit amendments, minor permit modification procedures and operational flexibility provisions, as described in Sections X., XI., and XII. of this Part C, Sections III. and IV. of Part A, and except for applications for coverage under general operating permits as described in Section VIII. of this Part C, all permit proceedings, including initial permit issuance, significant modifications, re-openings and renewals, and are subject to public notice, comment and opportunity for public hearing requirements. A minor source voluntarily applying for an operating permit is not subject to the public participation requirements of this Part C unless the source is required to have a federally enforceable emission limitation to be considered a (synthetic) minor source. Minor sources that are not synthetic minors and major sources of Colorado-only Hazardous Air Pollutants subject to the operating permit requirements solely due to state-only conditions shall be subject to the public participation requirements where warranted in accordance with the provisions of Part B of this Regulation Number 3.

VI.B. The Division shall, within fifteen calendar days after the preparation of the preliminary analysis, cause public notice of the application to be published in a newspaper of general distribution in the area in which the proposed project or activity is or will be located or in a State publication designed to give general public notice, and by such other means if necessary to assure notice to the affected public, which may include posting of such notice on the publicly accessible portion of the Division's web site. The Division shall cause a copy of the preliminary analysis and application to be filed with the county clerk for each county in which the source is or will be located. The Division shall send written or electronic notice to the applicant, to persons requesting notice of permit applications that are subject to public notice requirements, and to affected states. The newspaper notice or other State publication shall contain the information listed below in VI.B.1. through VI.B.9. The Division's web site notice shall contain all the following information in Sections VI.B.1. through VI.B.15.:

VI.B.1. The name and address of the permittee;

VI.B.2. The name and address of the affected facility;

VI.B.3. The Division's name and address;

VI.B.4. The activity or activities proposed in the permit application;

VI.B.5. The emissions change involved in any permit modification;

VI.B.6. The name, address, and telephone number of a Division staff contact from whom interested persons may obtain additional information, including copies of the permit draft, the application, all relevant supporting materials, the compliance plan, the monitoring and compliance certification report, and all other materials available to the Division that are relevant to its permit decision;

VI.B.7. Information regarding scheduling of any public comment hearing if one is requested;

VI.B.8. That the Division will receive and consider public comments for thirty calendar days after such publication;

VI.B.9. The Division's preliminary determination of approval, conditional approval, or disapproval of the application;

VI.B.10. That any interested person may submit a written request for a public comment hearing to be held by the Commission to receive comments regarding the concerns listed in Sections VI.B.11. through VI.B.15., below, the sufficiency of the preliminary analysis, and whether the Division should approve or deny the permit application. Any written request for a public comment hearing must be submitted to the Division within thirty days of publication;

VI.B.10.a. Written requests for a public comment hearing shall be directed to the Air Pollution Control Division's office at 4300 Cherry Creek Drive South, Denver, Colorado 80246-1530;

VI.B.10.b. Requests shall: (i) identify the individual or group applying; (ii) state his or her address and phone number; (iii) state the reasons for the request; (iv) state the manner in which the person is affected by the proceedings; and (v) provide an explanation of why the person's interests are not already adequately represented.

VI.B.11. That comments concerning the ability of the proposed activity to comply with applicable requirements are solicited from any interested person;

VI.B.12. That comments are solicited on the air quality impacts of the source or modification;

VI.B.13. That comments are solicited on alternatives to the source or modification;

VI.B.14. That comments are solicited on the control technology required;

VI.B.15. That comments are being solicited on any other appropriate air quality considerations.

VI.C. Within fifteen calendar days after the preparation of the preliminary analysis for those applications subject to the requirements of this Part C, the Division shall forward to the applicant written notice of the applicant's right to a public comment hearing with respect to the application pursuant to Section VII. of the Commission’s Procedural Rules.

VI.D. A public comment hearing request pursuant to Section VI.B. of this Part C must be transmitted by the Division to the Commission, along with the complete permit application, the preliminary analysis, the draft permit, and any written comments received by the Division within five days after the end of the thirty-day comment period. At least thirty days prior to the date set for the public comment hearing, the notice of public comment hearing, the preliminary analysis and the draft permit shall be posted on the Division’s web site. No substantive revisions shall be made to the draft permit during the thirty days prior to the public comment hearing. The applicant may submit, within ten days following the close of the public comment period, a response to any comments made. Nothing herein shall impede the Division's ability to meet required processing timeframes or other required time periods contained in this regulation.

VI.E. The Commission shall hold a public comment hearing within sixty days of its receipt of the request for a hearing pursuant to Section VI.B. or VI.C. of this Part C, unless such greater time is agreed to by the applicant and the Division. The Division shall appear at the public comment hearing in order to present the permit application. At least thirty days prior to such hearing, notice thereof shall be mailed by the Commission to the applicant, and to any interested person who submitted a request for a public hearing, printed in a newspaper of general distribution in the area of the proposed source or modification, and submitted for public review with the county clerk for each county in which the source or modification is or will be located.

VI.F. The Division shall maintain a record of the commenter and of the issues raised during the public comment and public hearing process for a period of five years.

VI.G. The Division shall notify the Administrator and any affected state, in writing, of any refusal to accept all recommendations for the proposed permit that the affected state submitted during the public or affected state review period, as well as reasons for such refusal.

VI.H. If the Administrator does not object in writing to the issuance of any proposed permit within forty-five days of receipt of the proposed permit, any person may petition the Administrator within sixty days of expiration of the Administrator's forty-five day review period to make such objection. Any such petition shall be based only on objections to the permit that were raised with reasonable specificity during the public comment period as provided for in Section VI.B. of this Part C, unless the petitioner demonstrates that it was impracticable to raise such objections within that period, or unless the grounds for such objection arose after such period

VI.H.1. A petition for review does not stay the effectiveness of a permit or its requirements if the permit was issued after the end of the forty-five day review period and prior to an U.S. EPA objection.

VI.H.2. If, pursuant to a petition filed under this Section VI.H., the U.S. EPA objects to the issuance of a permit prior to its issuance, the Division shall not issue the permit until the U.S. EPA's objection has been resolved.

VI.H.3. If, pursuant to a petition filed under this Section VI.H., the U.S. EPA objects to the issuance of a permit after it has been issued by the Division, the Administrator may modify, terminate, or revoke such permit and the Division may thereafter issue only a revised permit that satisfies the U.S. EPA's objection.

VI.H.4. In no event will any proceeding under this Section VI.H. cause a source to be in violation of the requirement to have submitted a timely and complete application.

**VII. Emergency Provisions**

VII.A. An emergency means any situation arising from sudden and reasonably unforeseeable events beyond the control of the source, including acts of god, which situation requires immediate corrective action to restore normal operation, and that causes the source to exceed a technology based emission limitation under the permit, due to unavoidable increases in emissions attributable to the emergency. An emergency shall not include noncompliance to the extent caused by improperly designed equipment, lack of preventative maintenance, careless or improper operation, or operator error.

VII.B. An emergency constitutes an affirmative defense to an action brought for noncompliance with such technology-based emission limitations if the conditions of Section VII.C. are met. In any enforcement proceeding, the permittee seeking to establish the occurrence of an emergency has the burden of proof.

VII.C. The affirmative defense for an emergency shall be demonstrated through properly signed, contemporaneous operating logs, or other relevant evidence that:

VII.C.1. An emergency occurred and that the permittee can identify the cause(s) of the emergency;

VII.C.2. The permitted facility was at the time being properly operated;

VII.C.3. During the period of the emergency, the permittee took all reasonable steps to minimize levels of emissions that exceeded the emission standards, or other requirements in the permit; and

VII.C.4. The permittee submitted oral notice of the emergency to the Division no later than noon of the next working day following the emergency, and followed by written notice within one month of the time when emission limitations were exceeded due to the emergency. This notice fulfills the requirement of Section V.C.7.b. of this Part C. This notice must contain a description of the emergency, any steps taken to mitigate emissions, and corrective actions taken.

VII.C.5. This provision is in addition to any emergency or upset provision contained in any applicable requirement.

**VIII. General Operating Permits**

VIII.A. The Division may, after notice and opportunity for public participation provided under Section VI. of this Part C, issue a general permit covering numerous similar sources that would otherwise be required to obtain an operating permit pursuant to this Part C. Any general permit shall comply with all requirements applicable to other operating permits and shall identify criteria by which sources may qualify for the general permit. For sources that qualify, the Division shall grant the conditions and terms of the general permit. Notwithstanding the permit shield, a source shall be subject to enforcement action for operation without an operating permit if the source is later determined not to qualify for the conditions and terms of the general permit. General permits are not authorized for affected sources under the acid rain program unless otherwise provided in regulations promulgated under Title IV of the Federal Act. A general permit may be issued for the following purposes:

VIII.A.1. To establish terms and conditions to implement applicable requirements for a source category;

VIII.A.2. To establish terms and conditions to implement applicable requirements in lieu of reopening the permit to incorporate additional applicable requirements pursuant to Section XIII of this Part C;

VIII.A.3. To establish terms and conditions for new requirements that apply to sources with existing permits, so long as no terms or conditions of the existing permit are being violated;

VIII.A.4. To establish federally enforceable caps on emissions from sources in a specified category.

VIII.A.5. The Division may issue a general permit if it finds that:

VIII.A.5.a. There are several permittees, permit applicants, or potential permit applicants who have the same or substantially similar operations, emissions, activities, or facilities;

VIII.A.5.b. The permittees, permit applicants, or potential permit applicants emit the same type of regulated air pollutants;

VIII.A.5.c. The operations, emissions, activities, or facilities are subject to the same or similar standards, limitations, and operating requirements; and

VIII.A.5.d. The operations, emissions, activities, or facilities are subject to the same or similar monitoring, record keeping, and reporting requirements.

VIII.B. A general permit developed under this section shall identify criteria by which sources may qualify for the general permit. After a general permit has been developed, any eligible source may submit an application to be covered under the permit.

VIII.C. An application for coverage under a general permit shall identify the source and provide information sufficient to demonstrate that it falls within the source category covered by the general permit, together with all information necessary to determine qualification for, and to assure compliance with, the general permit including a compliance plan in accordance with Section III.C.8. of this Part C.

VIII.D. A final action approving a request for coverage under a general permit shall not be subject to judicial review. A source may seek judicial review of a final action denying coverage under a general permit.

VIII.E. If some, but not all, of a source's operations, activities, and emissions are eligible for coverage under one or more general permits, the source may apply for and receive coverage under the general permits for the operations, activities, and emissions that are so eligible. If the source is required under Section II. of this Part C to obtain an operating permit addressing the remainder of its operations, activities, and emissions, it may apply for, and receive, an operating permit that addresses specifically those items not covered by general permits. In such a case, the source's operating permit shall identify all operations, activities, and emissions that are subject to general permits and incorporate those general permits by reference.

VIII.F. Sources that would qualify for a general permit must apply to the Division for coverage under the terms of the general permit or must apply for an operating permit under Section III. of this Part C. without repeating the public participation procedures required under Section VI. of this Part C, the Division may grant a source's request for authorization to operate under a general permit. Such a grant shall not be a final permit action for purposes of judicial review.

VIII.G. Upon granting of the general permit by the Division, the source must keep a copy of the permit on-site at all times.

VIII.H. A general operating permit shall not be issued to a major source where issuance of a general permit would cause a violation of any applicable requirement in any other operating permit held by the source, or where issuance of a general operating permit operates to allow the source to avoid a modification under Title I of the Federal Act.

VIII.I. A source may commence operations under the general operating permit sixty days after submitting its application for a general operating permit unless notified by the Division within that time period that additional information is required to determine whether the source qualifies for a general operating permit. Nothing herein precludes the Division from requesting additional information after sixty days have elapsed since the source's submission of a general operating permit application.

VIII.J. The application shield shall become effective upon the source's submission of a complete application, in accordance with Section II.B. of this Part C.

VIII.K. The permit shield shall become effective upon issuance of the general operating permit by the Division.

VIII.L. The general operating permits, as developed by the Division, shall be required to undergo review by the Administrator, affected states and the public, as set forth in Sections V.B., VI., and IX. of this Part C every five years.

## IX. Review By Affected States

IX.A. The Division shall give notice of each draft-operating permit to any affected state on or before the time that the Division provides public notice under Section VI. of this Part C, except where the requirements for timing of notices are different pursuant to Sections X., X.I., and XII. of this Part C.

IX.B. The Division shall notify the U.S. EPA and any affected state in writing of any refusal by the Division to accept all recommendations for the proposed permit that the affected state submitted during the public or affected state review period. Said notice will include the Division's reasons for not accepting any such recommendation. The Division is not required to accept recommendations that are not based on applicable requirements.

## X. Minor Permit Modification Procedures

X.A. Minor permit modification procedures may be used only for those permit modifications that:

X.A.1. Do not violate any applicable requirement;

X.A.2. Do not involve significant changes to existing monitoring, reporting, or record keeping requirements in a permit;

X.A.3. Do not require or change a case-by-case determination of an emission limitation or other standard or a source-specific determination for temporary sources of ambient impacts, or a visibility or increment analysis;

X.A.4. Do not seek to establish or change a permit term or condition for which there is no corresponding underlying applicable requirement and that the source has assumed to avoid an applicable requirement to which the source would otherwise be subject. Such terms and conditions include:

X.A.4.a. A federally enforceable emissions cap assumed to avoid classification as a modification under any provision of Title I of the Federal Act, including but not limited to modifications under Part 2 of the state Act (prevention of significant deterioration), Part 3 of the state Act (attainment), or New Source Performance Standards (Regulation Number 6);

X.A.4.b. An alternative emissions limit approved pursuant to regulations promulgated under Colorado Revised Statute Section 25-7-109.3 or Section 112(i)(5) of the federal Act (Regulation Number 8);

X.A.5. Are excepted from the definition of permit modification in Section I.A.3. of Part C.

X.A.6. Are not otherwise required by the Division to be processed as a significant modification.

X.B. Notwithstanding Sections X.A.5.and XI. (group processing criteria), minor permit modification procedures may be used for permit modifications involving the use of economic incentives, marketable permits, emissions trading, and other approved approaches, to the extent that such minor permit modification procedures are otherwise provided for in the state implementation plan promulgated pursuant to the state Act.

X.C. An application for a minor permit modification shall be prepared on forms supplied by the Division.

X.D. Applications shall meet the requirements of an application for an operating permit as set forth in Commission Regulation Number 3, Part C, Section III., and be signed by a responsible official. The applicant shall furnish all information and data required by the Division to evaluate the minor permit modification application, and shall include the following:

X.D.1. A description of the change, the emissions resulting from the change, and any new applicable requirements that will apply if the change occurs;

X.D.2. The sources suggested draft permit;

X.D.3. Certification by a responsible official that the proposed modification meets the criteria for use of minor permit modification procedures and a request that such procedures be used; and

X.D.4. Completed forms supplied by the Division for the Division to use to notify the Administrator and affected states.

X.D.5. Data necessary to allow the Division to determine whether the source complies with:

X.D.5.a. All applicable emission control regulations;

X.D.5.b. Applicable regulations for the control of hazardous air pollutants;

X.D.5.c. Requirements of the nonattainment and attainment programs (Sections V. and VI. of Part D of this regulation); and

X.D.5.d. Any applicable ambient air quality standards and all applicable regulations. When the data includes modeling, the model used shall be an appropriate one given the topography, meteorology, and other characteristics of the region, which the source will impact;

X.D.6. Copies of Air Pollutant Emission Notice(s) on file with the Division indicating production/process rates for which the operating permit is to be evaluated, or, if Air Pollutant Emission Notice(s) have not been previously filed, a new Air Pollutant Emission Notice(s) shall be submitted in accordance with Part A, Section II. The Air Pollutant Emission Notice fee will not be charged for submission of copies of current Air Pollutant Emission Notice(s) previously filed with the Division.

X.E. An application for a minor permit modification will not be deemed to be complete until all information and data (including any required ambient air impact analysis in accordance with Section VIII. of Part A) required to evaluate the application have been submitted to the Division.

X.F. Within five working days of receipt of a complete minor permit modification application, the Division shall send a copy of the notice completed pursuant to Section X.D.4., above, to the Administrator.

X.G. Within five working days of receipt of a complete minor permit modification application, the Division shall send a copy of the notice completed pursuant to Section X.D.4., above, to affected states. Notice to affected states shall not be required for minor sources that voluntarily apply for an operating permit to obtain the operational flexibility set forth in this Part C. The Division shall notify the Administrator and any affected state of any refusal by the Division to accept all recommendations for the proposed revised permit under the minor permit modification procedures that the affected state submitted during its review period. The Division shall include in such notice its reasons for not accepting any such recommendation. The Division is not required to accept recommendations that are not based on applicable requirements under the state or Federal Act. Notice to affected states and to the Administrator is not required for minor modifications involving state only conditions.

X.H. Within ninety calendar days of receipt of a complete application for minor permit modification, or fifteen calendar days after the end of the Administrator's forty five day review period, whichever is later, the Division shall:

X.H.1. Issue the minor permit modification as proposed;

X.H.2. Deny the minor permit modification application;

X.H.3. Determine that the requested modification does not meet the minor permit modification criteria and should be reviewed under the significant modification procedures; or

X.H.4. Revise the draft minor permit modification and transmit to the Administrator the new proposed minor permit modification as required in this Regulation Number 3, Part C, Section V.B.5.

X.I. A source shall be allowed to make the changes proposed in its application for minor permit modification immediately after it files such application. If the source elects to make such changes, and until the Division issues its final determination in accordance with Sections X.H.1. through X.H.4., above, the source must comply with both the applicable requirements governing the change and the proposed permit terms and conditions. During this time, the source does not need to comply with existing permit terms and conditions it seeks to modify, but if the source fails to comply with its proposed permit terms and conditions during this period, the existing permit terms and conditions it seeks to modify shall be fully enforceable by the Division.

X.J. The permit shield shall not extend to minor permit modifications.

X.K. A permit modification for purposes of the acid rain portion of a permit shall be governed by regulations promulgated under Title IV of the Federal Act, found at Code of Federal Regulations Title 40, Part 72.

**XI. Procedures For Group Processing Of Minor Permit Modification Applications**

XI.A. Group processing of applications for modifications eligible for minor permit modification processing may be used only for those permit modifications that:

XI.A.1. Meet the requirements of Part C, Sections X.A.1. through X.A.6., above, for minor permit modification procedures; and

XI.A.2. That collectively is below the lowest threshold level as set forth below:

XI.A.2.a. Ten percent of the emissions allowed by the permit for the emissions unit for which the change is requested; or

XI.A.2.b. Twenty percent of the applicable definition of major source; or

XI.A.2.c. Five tons per year, whichever is less.

XI.B. An application shall be filed with the Division for each change the source proposes to make, describing the change and the new emissions resulting from the change and notifying the Division that the source intends to request group processing of such minor modification applications in accordance with Section XI.C.4., below. An application for group processing of minor permit modifications shall be prepared on forms supplied by the Division.

XI.C. Applications shall meet the requirements of an application for an operating permit as set forth in Commission Regulation Number 3, Part C, Section III., and be signed by a responsible official. The applicant shall furnish all information and data (including any required ambient air impact analysis in accordance with Section VIII. of Part A of this regulation) required by the Division to evaluate the minor permit modification application and shall include the following:

XI.C.1. A description of the change, the emissions resulting from the change, and any new applicable requirements that will apply if the change occurs;

XI.C.2. The sources suggested draft permit;

XI.C.3. Certification by a responsible official that the proposed modification meets the criteria for use of group processing procedures and a request that such procedures be used;

XI.C.4. A list of the source's other pending applications awaiting group processing, and a determination of whether the requested modification, aggregated with these other applications, equals or exceeds the threshold set under Sections XI.A.2.a. through XI.A.2.c. of this Part C;

XI.C.5. Certification by a responsible official that the source has notified the U.S. EPA of the proposed modification. Such notification need only contain a brief description of the requested modification;

XI.C.6. Copies of Air Pollutant Emission Notice(s) on file with the Division indicating production/process rates for which the operating permit is to be evaluated, or, if Air Pollutant Emission Notice(s) have not been previously filed, a new Air Pollutant Emission Notice(s) shall be submitted in accordance with Part A, Section II. The Air Pollutant Emission Notice fee will not be charged for submission of copies of current Air Pollutant Emission Notice(s) previously filed with the Division.

XI.C.7. Completed forms for the permitting authority to use to notify the Administrator and affected states. Notice to affected states is not required for minor sources voluntarily applying for an operating permit to obtain the operational flexibility set forth in this Part C. Notice to affected states and the Administrator is not required for group processing of minor modifications involving state only conditions.

XI.C.8. As provided for in the state implementation plan, minor permit modifications made pursuant to this Section XI. will not trigger the procedural requirements otherwise applicable for modifications pursuant to Part B of this regulation.

XI.D. On a quarterly basis, or within five business days of receipt of an application demonstrating that the aggregate of a source's pending applications equals or exceeds the thresholds set forth in Section XI.A.2., whichever is earlier, the Division shall promptly notify the Administrator and affected states. A source shall only be allowed to aggregate its increased emissions caused by changes made in accordance with this Section XI. during each five-year permit term, except that any aggregation of emissions that equals or exceeds the thresholds set forth in Section A.2. shall trigger the procedural requirements set forth in this Section XI. All aggregation of emissions not addressed through the procedures set forth in this Section XI. shall be incorporated into the operating permit upon renewal.

The Division shall promptly notify the Administrator and any affected state of any refusal by the Division to accept all recommendations for the proposed revised permit under the group processing of minor permit modifications that the affected state submitted during its review period. The Division shall include in such notice the reasons for not accepting any such recommendation. The Division is not required to accept recommendations that are not based on applicable requirements under the state or Federal Acts.

XI.E. Within one hundred and eighty calendar days of receipt of a complete application for group processing of minor permit modifications under this Section XI., or fifteen calendar days after the end of the Administrator's forty-five days review period, whichever is later, the Division shall:

XI.E.1. Issue the minor permit modification as proposed;

XI.E.2. Deny the minor permit modification application;

XI.E.3. Determine that the requested modifications do not meet the minor permit modification criteria and should be reviewed under the significant modification procedures; or

XI.E.4. Revise the draft minor permit modification and transmit to the Administrator the new proposed minor permit modification.

XI.F. A source shall be allowed to make the changes proposed in its application for group processing of minor permit modifications immediately after it files such application. If the source elects to make such changes, and until the Division issues its final determination in accordance with Sections XI.E.1. through XI.E.4. above, the source must comply with both the applicable requirements governing the change and the proposed permit terms and conditions. During this time, the source does not need to comply with existing permit terms and conditions it seeks to modify, but if the source fails to comply with its proposed permit terms and conditions during this period, the existing permit terms and conditions it seeks to modify shall be fully enforceable by the Division.

XI.G. The permit shield shall not extend to minor permit modifications made pursuant to the group processing procedures in this Section XI.

## XII. Operational Flexibility

XII.A. Section 502(b)(10) changes

XII.A.1. No permit revision is necessary for changes within a permitted facility, if the changes are excepted from the definition of modification in Part A, Section I.B.28. of this Regulation Number 3, and the changes do not exceed the emissions allowable under the permit, whether expressed therein as a rate of emissions or in the terms of total emissions, and provided that notice is provided to the Division as set forth below:

XII.A.1.a. For each such change, the facility shall provide the Administrator and the Division with a minimum of seven days' written notification in advance of the proposed changes. The notice must be received by the Division no later than seven days in advance of the proposed changes. The source, the Division, and the Administrator shall attach each such notice to their copy of the relevant permit;

XII.A.1.b. For each such change, the written notification required above shall include a brief description of the change within the permitted facility, the date on which the change will occur, any change in emissions, and any permit term or condition that is no longer applicable because of the change;

XII.A.1.c. A source shall be allowed to make such change proposed in its notice on the day following the last day of the advance notice described in this section if the Division has not responded nor objected to the proposed change on or before that day; and

XII.A.1.d. The permit shield shall not apply to any changes made pursuant to this section. If subsequent changes cause the facility's operations and emissions to revert to those anticipated in the operating permit, the permittee resumes compliance with the terms and conditions of the permit, and has provided the Division and Administrator with a minimum of seven days' advance notice of such changes in accordance with the provisions of Section XII.A.1.a., above, the permit shield may be reinstated in accordance with the terms and conditions stated in the operating permit.

XII.A.2. Changes made pursuant to this Section XII.A. shall be incorporated into the operating permit at the time of renewal, at which time the permit shield shall apply.

XII.B. Off Permit Changes

No permit revision shall be necessary for changes within a permitted facility, not otherwise addressed or prohibited in the permit or in the provisions of this Section XII.B., governing off permit changes. This provision shall apply to changes, which are excepted from the definition of permit modification in Section I.A.3. of this Part C, or if such changes are subject to requirements of Title IV of the Federal Act (acid rain program). As provided for in the state implementation plan, changes made pursuant to this Section XII.B. shall not trigger the procedural requirements contained in Part B of this regulation for obtaining a construction permit.

XII.B.1. Each such change shall meet all applicable requirements and shall not violate any existing permit term or condition.

XII.B.2. The source must provide contemporaneous written notice to the permitting authority and the Administrator of each such change, except for changes that have been determined to be insignificant by the Commission pursuant to regulation. Such written notice shall describe each such change, including the date, any change in emissions, pollutants emitted, and any applicable requirement that would apply as a result of the change. A revised Air Pollutant Emission Notice shall be submitted in accordance with the provisions of Part A, Section II., along with the written notice required in this Section XII.B.2.

XII.B.3. The permit shield shall not apply to any such change made pursuant to this Section XII.B.

XII.B.4. The source shall keep a record describing changes made at the source that result in emissions of a regulated air pollutant subject to an applicable requirement, but not otherwise regulated under the permit, and the emissions resulting from those changes, including any other data necessary to show compliance with applicable ambient air quality standards.

XII.B.5. Changes made pursuant to this Section XII.B. shall be incorporated into the operating permit at the time of renewal.

**XIII. Reopening For Cause Of Permits Issued Pursuant To Part C**

XIII.A. A permit issued pursuant to Part C of this Commission Regulation Number 3, shall be reopened and revised under any of the following circumstances:

XIII.A.1. Additional applicable requirements become applicable to a major source with a remaining permit term of three or more years. Such reopening shall be completed no later than eighteen months after promulgation of the applicable requirement. No such reopening is required if the effective date of the requirement is later than the date on which the permit is due to expire, unless the original permit or any of its terms and conditions has been extended, or if a general permit is obtained to address the new requirement pursuant to Section VIII.A.2. of this Part C;

XIII.A.2. Additional requirements (including excess emissions requirements) become applicable to an affected source under the acid rain program. Upon approval by the Administrator, excess emissions offset plans shall be deemed to be incorporated into the permit;

XIII.A.3. The Division or the Administrator determines that the permit contains a material mistake or that inaccurate statements were made in establishing the emissions standards or other terms or conditions of the permit;

XIII.A.4. The Division or the Administrator determines that the permit must be revised or revoked to assure compliance with the applicable requirements;

XIII.A.5. Permit reopening and reissuance shall be processed using the procedures set forth in Sections III., IV., and V. of this Part C for permit issuance and permit renewal;

XIII.A.6. Proceedings to reopen and reissue permits affect only those parts of the permit for which cause to reopen exists; and

XIII.A.7. Reopening under this section of Part C shall not be initiated before notice of such intent is provided to the source by the Division at least thirty days in advance of the date that the permit is to be reopened. The Division may provide a shorter time period within which to give notice in the case of an emergency.

XIII.B. The Division shall extend the permit shield to those parts of the permit that have been changed pursuant to the reopening and reissuance proceedings of this section of Part C.

XIII.C. A source may choose to have its operating permit renewed during any proceeding for reopening the permit under this section, provided a complete application is submitted pursuant to Part C.

**XIV. Compliance Assurance Monitoring**

The regulations promulgated by the U.S. EPA listed in Section XIV.A.1., below, are hereby incorporated by reference by the Commission and made a part of the Colorado Commission regulations. Materials incorporated by reference are those in existence as of the date indicated and do not include later amendments. The material incorporated by reference is available for public inspection during regular business hours at the Office of the Commission, located at 4300 Cherry Creek Drive South, Denver, Colorado 80246-1530. The material incorporated by reference is also available through the United States Government Printing Office, online at www.gpo.gov/fdsys. Parties wishing to inspect these materials should contact the Technical Secretary of the Commission, located at the office of the Commission.

XIV.A.1. Air Pollution Control, Monitoring, Operating Permits, Reporting and Record Keeping Requirements: Compliance Assurance Monitoring, Code of Federal Regulations Title 40, Parts 64 and 70.6, October 22, 1997 (62 FR 54900).

Air Pollution Control, Monitoring, Operating Permits, Reporting and Record keeping Requirements: Compliance Assurance Monitoring, Code of Federal Regulations Title 40, Parts 64, 70.6 and 71.6, October 22, 1997 (62 FR 54900).

**PART D CONCERNING MAJOR STATIONARY SOURCE NEW SOURCE REVIEW AND PREVENTION OF SIGNIFICANT DETERIORATION**

**I. Applicability**

I.A. General Applicability

I.A.1. This Part D shall apply to any new or existing major stationary source.

Any new major stationary source or major modification, to which the requirements of this Part D apply, shall not begin actual construction in a nonattainment, attainment, or unclassifiable area unless a permit has been issued containing all applicable state and federal requirements.

I.A.2. Except as otherwise provided in Section XV. of this Part D, and consistent with the definition of major modification (Section II.A.23. of this part), a project is a major modification for a regulated NSR pollutant if it causes two types of emissions increases - a significant emissions increase (as defined in Section II.A.45. of this part), and a significant net emissions increase (as defined in Sections II.A.27. and II.A.44. of this part). The project is not a major modification if it does not cause a significant emissions increase. If the project causes a significant emissions increase, then the project is a major modification only if it also results in a significant net emissions increase.

I.A.3. The procedure for calculating (before beginning actual construction) whether a significant emissions increase (i.e., the first step of the process) will occur depends upon the type of emissions units being constructed or modified, according to Sections I.B.1. through I.B.3. of this part. The procedure for calculating (before beginning actual construction) whether a significant net emissions increase will occur at the major stationary source (i.e., the second step of the process) is contained in the definition of Net Emissions Increase (Section II.A.27. of this part). Regardless of any such preconstruction projections, a major modification results if the project causes a significant emissions increase and a significant net emissions increase.

I.B. Applicability Tests

I.B.1. Actual-to-projected-actual applicability test for projects that only involve existing emissions units.

A significant emissions increase of a regulated NSR pollutant is projected to occur if the sum of the difference between the projected actual emissions (as defined in Section II.A.38. of this part) and the baseline actual emissions (as defined in Sections II.A.4.a. and II.A.4.b. of this part, as applicable), for each existing emissions unit, equals or exceeds the significant amount for that pollutant (as defined in Section II.A.44. of this part).

I.B.2. Actual-to-potential test for projects that only involve construction of a new emissions unit(s).

A significant emissions increase of a regulated NSR pollutant is projected to occur if the sum of the difference between the potential to emit (as defined in Section I.B.37. of Part A of this regulation) from each new emissions unit following completion of the project and the baseline actual emissions (as defined in Section II.A.4. of this part) of these units before the project equals or exceeds the significant amount for that pollutant (as defined in Section II.A.44. of this part).

I.B.3. Hybrid test for projects that involve multiple types of emissions units.

A significant emissions increase of a regulated NSR pollutant is projected to occur if the sum of the emissions increases for each emissions unit, using the methods specified in Sections I.B.1. through I.B.3. of this part as applicable with respect to each type of emissions unit, equals or exceeds the significant amount for that pollutant (as defined in Section II.A.44. of this part).

I.B.4. An owner or operator of a major stationary source who conducts the actual-to-projected-actual test for a project that requires a minor permit modification in accordance with Section X. of Part C, requires a significant permit modification in accordance with Section I.A.3. of Part C, a modification as defined in Section I.B.28. of Part A or that requires a minor source permit under Part B shall submit a permit application including:

I.B.4.a. All calculations and supporting documentation used to determine baseline actual emissions of each emissions unit affected by the project;

I.B.4.b. All calculations and supporting documentation used to determine projected actual emissions of each existing emissions unit affected by the project;

I.B.4.c. A determination of that portion of each existing unit's emissions following the project that the unit could have accommodated during the consecutive twenty-four month period used to establish the baseline actual emissions and that are unrelated to the project, including any increased utilization due to product demand growth; and,

I.B.4.d. Any other information requested by the Division that may be needed to determine if a major modification will occur at each emissions unit affected by the project.

The information submitted in accordance with Section I.B.4.a. through I.B.4.d., above, shall be incorporated into an appendix to the major stationary source's Title V Operating permit or as a permit note in the construction permit.

The requirement that the owner or operator of a major stationary source who conducts the actual-to-projected-actual test for a project that requires a minor permit modification submit information in accordance with Sections I.B.4.a. through I.B.4.d., as set out in this Subsection I.B.4., shall not be federally enforceable and shall not be incorporated into the state implementation plan.

I.C. For any major stationary source requesting, or operating under, a Plant-wide Applicability Limitation (as defined in Section II.A.35.) for a regulated NSR pollutant, the major stationary source shall comply with the requirements of Section XV. of this part.

**II. Definitions**

II.A. The following definitions apply specifically to the provisions contained in this Part D.

II.A.1. Actual Emissions

The actual rate of emission of a regulated NSR pollutant from an emissions unit, determined as follows:

II.A.1.a. Actual emissions as of a particular date shall equal the average rate, in tons per year, at which the unit actually emitted the pollutant during a consecutive twenty-four month period that precedes the particular date and is representative of normal unit operation. A different period may be used if it is more representative of normal unit operation. Actual emissions shall be calculated using the unit's actual operating hours, production rates, and types of materials processed, stored or combusted or actual emission data during the selected time period;

II.A.1.b. The Division may presume that source-specific allowable emissions for the unit are equivalent to the actual emissions of the unit only if actual emissions cannot be determined pursuant to Section II.A.1.a., above;

II.A.1.c. For any emissions unit that has not begun normal operations on the particular date, actual emissions shall equal the potential to emit of the unit on that date.

II.A.1.d. This definition shall not apply for calculating whether a significant emissions increase has occurred, or for establishing a PAL under Section XV. of Part D of this regulation. Instead, Sections II.A.38. and II.A.4. of this part shall apply for these purposes.

II.A.2. Actuals PAL

For a major stationary source, means a PAL based on the baseline actual emissions (as defined in Sections II.A.4.a. through II.A.4.d. of this part) of all emissions units (as defined in the Common Provisions regulation) at the source that emit or have the potential to emit the PAL pollutant. For a GHG-only source, actuals PAL means a PAL based on the baseline actual emissions (as defined in Sections II.A.4.e. and II.A.4.f.) of all emissions units (as defined in Section II.A.13.b.) at the source that emit or have the potential to emit GHGs.

II.A.3. Air Quality Related Value

Any value of an area that may be affected by a change in air quality. Examples include flora, fauna, soil, water, visibility, cultural, and odor.

II.A.4. Baseline Actual Emissions

The rate of emissions, in tons per year, of a regulated NSR pollutant.

II.A.4.a. For any existing electric utility steam generating unit (as defined in Section II.A.14. of this part), baseline actual emissions means the average rate, in tons per year, at which the unit actually emitted the pollutant during any consecutive twenty-four month period selected by the owner or operator within the five year period immediately preceding when the owner or operator begins actual construction of the project. The Division shall allow the use of a different time period upon a determination that it is more representative of normal source operation.

II.A.4.a.(i) The average rate shall include fugitive emissions to the extent quantifiable, and emissions associated with startups, shutdowns, and malfunctions.

II.A.4.a.(ii) The average rate shall be adjusted downward to exclude any non-compliant emissions that occurred while the source was operating above any emission limitation that was legally enforceable during the consecutive twenty-four month period.

II.A.4.a.(iii) For a regulated NSR pollutant, when a project involves multiple emissions units, only one consecutive twenty-four month period may be used to determine the baseline actual emissions for the emissions units being changed. A different consecutive twenty-four month period can be used for each regulated NSR pollutant.

II.A.4.a.(iv) The average rate shall not be based on any consecutive twenty-four month period for which there is inadequate information for determining annual emissions, in tons per year, and for adjusting this amount if required by Section II.A.4.a.(ii).

II.A.4.b. For an existing emissions unit (other than an electric utility steam generating unit), baseline actual emissions means the average rate, in tons per year, at which the emissions unit actually emitted the pollutant during any consecutive twenty-four month period selected by the owner or operator within the ten year period immediately preceding either the date the owner or operator begins actual construction of the project, or the date a complete permit application is received by the Division for a permit required under this Part D, except that the ten year period shall not include any period earlier than November 15, 1990.

II.A.4.b.(i) The average rate shall include fugitive emissions to the extent quantifiable, and emissions associated with startups, shutdowns, and malfunctions.

II.A.4.b.(ii) The average rate shall be adjusted downward to exclude any non-compliant emissions that occurred while the source was operating above an emission limitation that was legally enforceable during the consecutive twenty-four month period.

II.A.4.b.(iii) The average rate shall be adjusted downward to exclude any emissions that would have exceeded an emission limitation with which the major stationary source must currently comply, had the major stationary source been required to comply with such limitations during the consecutive twenty-four month period. However, if an emission limitation is part of a maximum achievable control technology standard contained in Part E of Regulation Number 8, the baseline actual emissions need only be adjusted if the State has taken credit for such emissions reductions in an attainment demonstration or maintenance plan.

II.A.4.b.(iv) For a regulated NSR pollutant, when a project involves multiple emissions units, only one consecutive twenty-four month period must be used to determine the baseline actual emissions for the emissions units being changed. A different consecutive twenty-four month period can be used for each regulated NSR pollutant.

II.A.4.b.(v) The average rate shall not be based on any consecutive twenty-four month period for which there is inadequate information for determining annual emissions, in tons per year, and for adjusting this amount if required under Sections II.A.4.b.(ii) and II.A.4.b.(iii) of this part.

II.A.4.c. For a new emissions unit, the baseline actual emissions for purposes of determining the emissions increase that will result from the initial construction and operation of such unit shall equal zero; and thereafter, for all other purposes, shall equal the unit's potential to emit (as defined in Section I.B.37. of Part A of this regulation).

II.A.4.d. For a PAL for a major stationary source, the baseline actual emissions shall be calculated for existing electric utility steam generating units in accordance with the procedures contained in Section II.A.4.a., for other existing emissions units in accordance with the procedures contained in Section II.A.4.b., and for a new emissions unit in accordance with the procedures contained in Section II.A.4.c.

II.A.4.e. For a GHG PAL means the average rate, in tons per year CO2e or tons per year GHG, as applicable, at which the emissions unit actually emitted GHGs during any consecutive 24-month period selected by the owner or operator within the 10-year period immediately preceding either the date the owner or operator begins construction of the project, or the date a complete permit application is received by the Division for a permit required under this Part D or by the Division for a permit required by a plan, whichever is earlier.

II.A.4.f. For any existing electric utility steam generating unit (as defined in Section II.A.14. of this part), baseline actual emissions for a GHG PAL means the average rate, in tons per year CO2e or tons per year GHG, at which the unit actually emitted the pollutant during any consecutive twenty-four month period selected by the owner or operator within the five year period immediately preceding when the owner or operator begins actual construction of the project. The Division shall allow the use of a different time period upon a determination that it is more representative of normal source operation.

II.A.4.f.(i) The average rate shall include fugitive emissions to the extent quantifiable, and emissions associated with startups, shutdowns, and malfunctions.

II.A.4.f.(ii) The average rate shall be adjusted downward to exclude any non-compliant emissions that occurred while the source was operating above any emission limitation that was legally enforceable during the consecutive twenty-four month period.

II.A.4.f.(iii) The average rate shall be adjusted downward to exclude any emissions that would have exceeded an emission limitation with which the stationary source must currently comply, had such stationary source been required to comply with such limitations during the consecutive 24-month period.

II.A.4.f.(iv) The average rate shall not be based on any consecutive twenty-four month period for which there is inadequate information for determining annual GHG emissions and for adjusting this amount if required by Sections II.A.4.a.(ii) and II.A.4.a.(iii).

II.A.5. Baseline Area

II.A.5.a. Any intrastate area (and every part thereof) designated as attainment or unclassifiable under Sections 107(d)(1)(A)(ii) or (iii) of the Federal Act in which the major source or major modification establishing the minor source baseline date would construct or would have an air quality impact for the pollutant for which the baseline date is established, as follows: equal to or greater than one microgram/cubic meter (1 µg/m3) (annual average) for SO2, NO2, or PM10; or equal to or greater than 0.3 µg/m3) (annual average) for PM2.5.

II.A.5.b. Area redesignations under Section 107(d)(1)(A)(ii) or (iii) of the Federal Act cannot intersect or be smaller than the area of impact of any major stationary source or major modification that:

II.A.5.b.(i) Establishes a minor source baseline date, or

II.A.5.b.(ii) Is subject to this Part D, and would be constructed in the same state as the state proposing the redesignation.

II.A.5.c. Any baseline area established originally for the total suspended particulate increments shall remain in effect and shall apply for purposes of determining the amount of available PM10 increments, except that such baseline area shall not remain in effect if the permit authority rescinds the corresponding minor source baseline date in accordance with Section II.A.26.c.

II.A.6. Baseline Concentration

The ambient concentration level that exists in the baseline area at the time of the applicable minor source baseline date. A baseline concentration is determined for each pollutant for which a minor source baseline date is established and shall include:

II.A.6.a. The actual emissions representative of sources in existence on the applicable minor source baseline date, except as otherwise provided in this definition; and

II.A.6.b. The allowable emissions from major stationary sources that commenced construction before the major source baseline date, but were not in operation by the applicable minor source baseline date.

II.A.6.c. The following will not be included in the baseline concentration and will affect the applicable maximum allowable increase(s):

II.A.6.c.(i) Actual emissions from any major stationary source on which construction commenced after the major source baseline date; and

II.A.6.c.(ii) Actual emission increases and decreases at any stationary source occurring after the minor source baseline date.

II.A.7. Begin Actual Construction

Initiation of physical on-site construction activities on an emissions unit that are of a permanent nature. Such activities include, but are not limited to, installation of building supports and foundations, laying of underground pipe work, and construction of permanent storage structures. With respect to a change in the method of operation, this term refers to those on-site activities other than preparatory activities that mark the initiation of the change.

II.A.8. Best Available Control Technology (BACT)

An emission limitation (including a visible emissions standard) based on the maximum degree of reduction of each regulated NSR pollutant that would be emitted from any proposed major stationary source or major modification that the Division or Commission, on a case-by-case basis, taking into account energy, environmental, and economic impacts and other costs, determines is achievable for such source or modification through application of production processes or available methods, systems, and techniques, including fuel cleaning or treatment or innovative fuel combustion techniques for control of such pollutant. In no event shall application of the best available control technology result in emissions of any pollutant that would exceed emissions allowed by the applicable standards in the Code of Federal Regulations, Title 40, Parts 60 and 61 (Regulation Number 6, Part A, and Regulation Number 8, Part A) as in effect on the effective date of this clause, but not including later amendments, unless such amendments are specifically incorporated by reference in accordance with the provisions of Colorado Revised Statutes Section 24-4-103 (12.5). Information as to the availability of such standards may be obtained from the Director, Air Pollution Control Division, Colorado Department of Public Health and Environment, 4300 Cherry Creek Drive South, Denver, Colorado 80246-1530.

If the Division or Commission determines that technological or economic limitations on the application of measurement methodology to a particular emissions unit would make the imposition of an emissions standard infeasible, it may instead prescribe designs, equipment, work practices, operational standards or combination thereof, to satisfy the requirement for the application of best available control technology. Such standard shall, to the degree possible, set forth the emissions reduction achievable by implementation of such design, equipment, work practice or operation and shall provide for compliance by means that achieve equivalent results.

II.A.9. Clean Coal Technology

Any technology, including technologies applied at the pre-combustion, combustion, or post-combustion stage, at a new or existing facility that will achieve significant reductions in air emissions of sulfur dioxide or oxides of nitrogen associated with the utilization of coal in the generation of electricity, or process steam which was not in widespread use as of November 15, 1990.

II.A.10. Clean Coal Technology Demonstration Project

A project using funds appropriated under the heading “Department of Energy-Clean Coal Technology,” up to a total amount of $2.5 billion for commercial demonstration of clean coal technology, or similar projects funded through appropriations for the U.S. EPA. The federal contribution for a qualifying project shall be at least twenty percent of the total cost of the demonstration project.

II.A.11. Complete

In reference to an application for a major NSR permit, an application that contains all the information necessary for processing the application. Designating an application complete for purposes of permit processing does not preclude the Division from requesting or accepting any additional information.

II.A.11.a. At a minimum, a complete application for a permit to construct a major source or major modification subject to the requirements of this Part D shall include:

II.A.11.a.(i) All monitoring data required pursuant to this regulation and an analysis of ambient air quality in accordance with Section VI.A.3. of this part;

II.A.11.a.(ii) The impact analysis required by Section VI.A.2. of this part, a written summary of the data inputs to the model, and a topographic presentation of the resultant concentrations of each pollutant modeled for each applicable ambient standard or Prevention of Significant Deterioration increment within the impact area of the source;

II.A.11.a.(iii) A report of the regulatory status of the model pursuant to Section VIII.A.1. of Part A;

II.A.11.a.(iv) A demonstration that the proposed technological system of continuous emission reduction that is to be used will enable such source to comply continuously with the standards of performance that are to apply to such source and that the emission inputs to the model for the impact analysis are equivalent to the emissions allowed by such standards of performance;

II.A.11.a.(v) A description of the devices or systems that will be installed to monitor the emissions of each pollutant that will be emitted in significant amounts, maintaining such devices or systems, and the schedule and format for reporting the results of such emission monitoring to the Division;

II.A.11.a.(vi) The additional impact analysis required by Section VI.A.6. of this part, any demonstration of facts needed to establish a claim by the applicant to qualify for any exemption or exclusion under Section VI.B. of this part;

II.A.11.a.(vii) A schedule of construction in accordance with Section III.G.2. of Part B;

II.A.11.a.(viii) An additional copy of the application for the federal land manager of each affected Class 1 area, for the U.S. EPA, for the county Commissioner, and for public notice (county clerk). Two additional copies shall be submitted for interested public groups.

II.A.12. Construction

Any physical change or change in the method of operation (including fabrication, erection, installation, demolition, or modification of an emissions unit) that would result in a change in actual emissions

II.A.13. Emissions Unit

II.A.13.a. Any part of a stationary source that emits or would have the potential to emit any regulated NSR pollutant and includes an electric steam-generating unit as defined in Section II.A.14. of this part. For purposes of this Part D, there are two types of emissions units described in Section II.A.13.a.(i) and II.A.13.a.(ii), below.

II.A.13.a.(i) A new emissions unit is any emissions unit that is (or will be) newly constructed and that has existed for less than two years from the date such emissions unit first operated.

II.A.13.a.(ii) An existing emissions unit is any emissions unit that does not meet the requirements in Section II.A.13.a.(i), above. A replacement unit (as defined in Section II.A.41. of this part) is an existing emissions unit.

II.A.13.b. With respect to GHGs means any part of a stationary source that emits or has the potential to emit GHGs. For purposes of Section XV., there are two types of emissions units:

II.A.13.b.(i) A new emissions unit is any emissions unit that is (or will be) newly constructed and that has existed for less than two years from the date such emissions unit first operated.

II.A.13.b.(ii) An existing emissions unit is any emissions unit that does not meet the requirements in Section II.A.13.b.(i).

II.A.14. Electric Utility Steam Generating Unit

Any steam electric generating unit that is constructed for the purpose of supplying more than one-third of its potential electrical output capacity and more than twenty-five megawatts electrical output to any utility power distribution system for sale. Any steam supplied to a steam distribution system for the purpose of providing steam to a steam-electric generator that would produce electrical energy for sale is also considered in determining the electrical energy output capacity of the affected facility.

II.A.15. Federal Land Manager (FLM)

With respect to any lands of the United States, the secretary of the department with authority over such lands.

II.A.16. GHG-only source

Any existing stationary source that emits or has the potential to emit GHGs in the amount equal to or greater than the amount of GHGs on a mass basis that would be sufficient for a new source to trigger permitting requirements for GHGs under Part D, Section II.A.25. and the amount of GHGs on a CO2e basis that would be sufficient for a new source to trigger permitting requirements for GHGs under Part A, Section I.B.44. at the time the PAL permit is being issued, but does not emit or have the potential to emit any other non-GHG regulated NSR pollutant at or above the applicable major source threshold. A GHG-only source may only obtain a PAL for GHG emissions under Part D, Section XV.

II.A.17. High Terrain

Any area having an elevation nine hundred feet or more above the base of the stack of a source.

II.A.18. Hydrocarbon Combustion Flare

Either a flare used to comply with an applicable new source performance standard or maximum achievable control technology standard (including uses of flares during startup, shutdown, or malfunction permitted under such standard), or a flare that serves to control emissions of waste streams comprised predominately of hydrocarbons and containing no more than 230 mg/dscm hydrogen sulfide.

II.A.19. Innovative Control Technology

Any system of air pollution control that has not been adequately demonstrated in practice, but would have a substantial likelihood of achieving greater continuous emissions reduction than any control system in current practice or of achieving at least comparable reductions at lower cost in terms of energy, economics, or non-air quality environmental impacts.

II.A.20. Low Terrain

Any area other than high terrain.

II.A.21. Lowest Achievable Emissions Rate (LAER)

For any source, the more stringent rate of emissions based on the following:

II.A.21.a. The most stringent emission limit contained in any state implementation plan for such class or category of stationary source, unless the owner or operator of the proposed stationary source demonstrates that such limits are not achievable; or

II.A.21.b. The most stringent emission limitation that is achieved in practice by such class or category of source. In no event shall application of the term permit a proposed new or modified stationary source to emit any pollutant in excess of the amount allowable under an applicable new source performance standard (Regulation Number 6).

II.A.22. Major Emissions Unit

II.A.22.a. Any emissions unit that emits or has the potential to emit one hundred tons per year or more of the PAL pollutant in an attainment area; or

II.A.22.b. Any emissions unit that emits or has the potential to emit the PAL pollutant in an amount that is equal to or greater than the major stationary source threshold (as defined in Section II.A.25. of this part) for the PAL pollutant for nonattainment areas.

II.A.22.c. For a GHG PAL issued on a CO2e basis, any emissions unit that emits or has the potential to emit equal to or greater than the amount of GHGs on a CO2e basis that would be sufficient for a new source to trigger permitting requirements under paragraph Part A, Section I.B.44. at the time the PAL permit is being issued.

II.A.23. Major Modification

Any physical change in or change in the method of operation of a major stationary source that would result in a significant emissions increase of a regulated NSR pollutant and a significant net emissions increase of that pollutant from the major stationary source.

II.A.23.a. Any significant emissions increase from any emissions units or net emissions increase at a major stationary source that is significant for volatile organic compounds or NOx shall be considered significant for ozone.

II.A.23.b. In the Denver Metropolitan PM10 nonattainment area, any net emission increase that is significant for sulfur dioxide or nitrogen oxides shall be considered significant for PM10.

II.A.23.c. A physical change or change in the method of operation shall not include routine maintenance, repair, and replacement.

II.A.23.d. A physical change or change in the method of operation, unless previously limited by any enforceable or federally enforceable permit condition that was established after January 6, 1975 for sources in attainment or unclassifiable areas and after December 21, 1976 for sources in nonattainment areas, shall not include:

II.A.23.d.(i) Use of an alternative fuel or raw material by reason of an order in effect under Sections 2(a) and (b) of the Federal Energy Supply and Environmental Coordination Act of 1974 (or any superseding legislation), a prohibition under the Power Plant and Industrial Fuel Use Act of 1978 (or any superseding legislation) or by reason of a natural gas curtailment plan in effect pursuant to the Federal Power Act;

II.A.23.d.(ii) Use of an alternative fuel because of an order or rule under Section 125 of the Federal Act;

II.A.23.d.(iii) Use of an alternative fuel at a steam-generating unit to the extent that the fuel is generated from municipal solid waste;

II.A.23.d.(iv) Use of an alternative fuel or raw material that:

II.A.23.d.(iv)(A) the stationary source in a nonattainment area was capable of accommodating prior to December 21, 1976, unless such change would be prohibited under a federally enforceable permit condition, or

II.A.23.d.(iv)(B) the stationary source in an attainment or unclassifiable area was capable of accommodating prior to January 6, 1975 unless such change would be prohibited under a federally enforceable permit condition, or

II.A.23.d.(iv)(C) the source is approved to use under any permit issued under this Regulation Number 3.

II.A.23.d.(v) An increase in the production rate, unless such change would be prohibited under a federally enforceable permit condition;

II.A.23.d.(vi) An increase in the hours of operation, unless such increase would be prohibited under a federally enforceable permit condition; or

II.A.23.d.(vii) Any change in ownership of a stationary source.

II.A.23.d.(viii) The installation, operation, cessation, or removal of a temporary clean coal technology demonstration project, if the project complies with:

II.A.23.d.(viii)(A)The Colorado State Implementation Plan, and

II.A.23.d.(viii)(B)Other requirements necessary to attain and maintain the National Ambient Air Quality Standards during the project and after it is terminated.

II.A.23.d.(ix) For major stationary sources in attainment areas:

II.A.23.d.(ix)(A) The installation or operation of a permanent clean coal technology demonstration project that constitutes re-powering, provided that the project does not result in an increase in the potential to emit of any regulated pollutant emitted by the unit. The exemption shall apply on a pollutant-by-pollutant basis.

II.A.23.d.(ix)(B) The reactivation of a very clean coal fired electric utility steam generating unit.

II.A.23.d.(x) The reactivation of a very clean coal fired electric utility steam generating unit.

II.A.23.e. This definition shall not apply with respect to a particular regulated NSR pollutant when the major stationary source is complying with the requirements under Section XV. of this Part D for a PAL for that pollutant. Instead, the definition in Section II.A.31. of this part shall apply.

II.A.23.f. Emissions caused by indirect sources of pollution, emissions from internal combustion engines on any vehicle, and emissions resulting from temporary construction or exploration activities shall be excluded in determining whether a major modification will occur.

Emissions from on-going construction are not considered to be temporary emissions, and are included in determining whether a major modification will occur.

Fugitive emissions from the listed sources in Section II.A.25.a. and any other stationary source category that, as of August 7, 1980 was regulated under Sections 111 or 112 of the Federal Act (as adopted in Regulations Nos. 6, Part A, and 8, Parts A and E) shall, to the extent quantifiable, be considered in calculating the potential to emit of the modification.

II.A.24. Major Source Baseline Date

II.A.24.a. In the case of PM10 and sulfur dioxide, January 6, 1975;

II.A.24.b. In the case of nitrogen dioxide, February 8, 1988; and

II.A.24.c. In the case of PM2.5, October 20, 2010.

II.A.25. Major Stationary Source

II.A.25.a. For the purpose of determining whether a source in an attainment or unclassifiable area is subject to the requirements of this Part D, major stationary source means:

II.A.25.a.(i) Any of the following stationary sources of air pollutants that emits, or has the potential to emit, one hundred tons per year or more of any regulated NSR pollutant:

II.A.25.a.(i)(A) Fossil fuel-fired steam electric plants of more than 250 million British thermal units per hour heat input

II.A.25.a.(i)(B) Coal cleaning plants (with thermal dryers)

II.A.25.a.(i)(C) Kraft pulp mills

II.A.25.a.(i)(D) Portland cement plants

II.A.25.a.(i)(E) Primary zinc smelters

II.A.25.a.(i)(F) Iron and steel mill plants

II.A.25.a.(i)(G) Primary aluminum ore reduction plants

II.A.25.a.(i)(H) Primary copper smelters

II.A.25.a.(i)(I) Municipal incinerators capable of charging more than 250 tons of refuse per day

II.A.25.a.(i)(J) Hydrofluoric, sulfuric, and nitric acid plants

II.A.25.a.(i)(K) Petroleum refineries

II.A.25.a.(i)(L) Lime plants

II.A.25.a.(i)(M) Phosphate rock processing plants

II.A.25.a.(i)(N) Coke oven batteries

II.A.25.a.(i)(O) Sulfur recovery plants

II.A.25.a.(i)(P) Carbon black plants (furnace process)

II.A.25.a.(i)(Q) Primary lead smelters

II.A.25.a.(i)(R) Fuel conversion plants

II.A.25.a.(i)(S) Sintering plants

II.A.25.a.(i)(T) Secondary metal production plants

II.A.25.a.(i)(U) Chemical process plants

II.A.25.a.(i)(V) Fossil fuel boilers (or combinations thereof) totaling more than 250 million British thermal units per hour heat input

II.A.25.a.(i)(W) Petroleum storage and transfer units with a total storage capacity exceeding 300,000 barrels

II.A.25.a.(i)(X) Taconite ore processing plants

II.A.25.a.(i)(Y) Glass fiber processing plants

II.A.25.a.(i)(Z) Charcoal production plants

II.A.25.a.(ii) Notwithstanding the stationary source size specified in Section II.A.25.a.(i), any stationary source that emits, or has the potential to emit, two hundred and fifty tons per year or more of any regulated NSR pollutant.

II.A.25.b. For the purpose of determining whether a source in a nonattainment area is subject to the requirements of Section V. of this part, and whether a source in an attainment area affecting a nonattainment area is subject to the requirements of Section VI.D. of this part, major stationary source means any stationary source of air pollutants that emits, or has the potential to emit 100 tons per year or more of any regulated NSR pollutant for which the area is nonattainment, except where the lower emissions thresholds in Sections II.A.25.b.(i)-(vi) apply. Additionally, a source causing or contributing to a violation of a national ambient air quality standard for any pollutant regulated under Section 110 of the Federal Act shall be considered a major stationary source when it has the potential to emit one hundred tons per year or more of that pollutant. The source will be considered to cause or contribute to a violation where the source exceeds the significance levels in the table under Section VI.D.2. of this Part D. Such source is subject to the requirements of Section VI. of this Part D.

II.A.25.b.(i) Fifty tons per year or more of volatile organic compounds or nitrogen oxides in any serious ozone nonattainment area.

II.A.25.b.(ii) Fifty tons per year or more of volatile organic compounds in any ozone transport region, except for any severe or extreme ozone nonattainment area.

II.A.25.b.(iii) Twenty five tons per year or more of volatile organic compounds or nitrogen oxides in any severe ozone nonattainment area.

II.A.25.b.(iv) Ten tons per year or more of volatile organic compounds or nitrogen oxides in any extreme ozone nonattainment area.

II.A.25.b.(v) Fifty tons per year or more of carbon monoxide in any serious carbon monoxide nonattainment area, where stationary sources significantly contribute to carbon monoxide levels.

II.A.25.b.(vi) Seventy tons per year or more of PM10 in any serious PM10 nonattainment area.

II.A.25.c. Major stationary source includes any physical change that would occur at a stationary source not otherwise qualifying as a major stationary source under Sections II.A.25.a and II.A.25.b. of this part, if the change would constitute a major stationary source by itself.

II.A.25.d. A major stationary source that is major for volatile organic compounds or NOx shall be considered major for ozone, except that emissions of negligibly reactive volatile organic compounds, as defined in the Common Provisions, shall not be included in the determination of major stationary source status for ozone.

II.A.25.e. The fugitive emissions of a stationary source shall not be included in determining for any of the purposes of this section whether it is a major stationary source, unless the source belongs to one of the categories of stationary sources listed in Section II.A.25.a.(i) or any other stationary source category which, as of August 7, 1980, is regulated under Section 111 or 112 of the Federal Act.

II.A.25.f. Emissions caused by indirect air pollution sources (as defined in Section I.B.24. of Part A of this regulation), emissions from internal combustion engines on any vehicle, and emissions resulting from temporary activities, such as construction or exploration, shall be excluded in determining whether a source is a major stationary source. Emissions from ongoing construction are not considered to be temporary emissions and are included in determining whether a major modification will occur.

II.A.25.g. A major stationary source in the Denver Metro PM10 attainment/maintenance area that is major for sulfur dioxide or nitrogen oxides shall be considered major for PM10.

II.A.26. Minor Source Baseline Date

II.A.26.a. The earliest date after the trigger date that a major stationary source or a major modification subject to the requirements of Section VI. of this Part D submits a complete application under the relevant regulations. The trigger date is:

II.A.26.a.(i) In the case of PM10 and sulfur dioxide, August 7, 1977;

II.A.26.a.(ii) In the case of nitrogen dioxide, February 8, 1988; and

II.A.26.a.(iii) In the case of PM2.5, October 20, 2011.

II.A.26.b. The baseline date is established for each pollutant for which increments or other equivalent measures have been established if:

II.A.26.b.(i) The area in which the proposed source or modification would construct is designated as attainment or unclassifiable under Sections 107(d)(1)(A)(ii) or (iii) of the Federal Act for the pollutant on the date of its complete application under Section VI. of this part; and

II.A.26.b.(ii) In the case of a major stationary source the pollutant would be emitted in significant amounts, or, in the case of a major modification, there would be a significant net emissions increase of the pollutant.

II.A.26.c. Any minor source baseline date established originally for the Total Suspended Particulates increments shall remain in effect and shall apply for purposes of determining the amount of available PM10 increments, except that the Division may rescind any such minor source baseline date where it can be shown, to the satisfaction of the Division, that the emissions increase from the major stationary source, or the net emissions increase from the major modification, responsible for triggering that date did not result in a significant amount of PM10 emissions.

II.A.27. Net Emissions Increase

II.A.27.a. With respect to any regulated NSR pollutant emitted by a major stationary source, the amount by which the sum of the following exceeds zero:

II.A.27.a.(i) The increase in emissions from a particular physical change or change in the method of operation at a stationary source calculated pursuant to Sections I.A.2. through I.A.3., and I.B. of this Part D; and

II.A.27.a.(ii) Any other increases and decreases in actual emissions at the major stationary source that are contemporaneous with the particular change and are otherwise creditable. Baseline actual emissions for calculating increases and decreases under this paragraph shall be determined as provided in the definition of baseline actual emissions, except that paragraphs II.A.4.a.(iii) and II.A.4.b.(iv) of this Part D shall not apply.

II.A.27.b. Contemporaneous - an increase or decrease in actual emissions is contemporaneous with the increase from the particular change only if it occurs within five years prior to the date that the increase from the particular change occurs.

II.A.27.c. An increase or decrease in actual emissions is creditable only if:

II.A.27.c.(i) It occurs within five years before the date that the increase or decrease occurs; and

II.A.27.c.(ii) The Division has not relied on it in issuing a permit for the source under Regulation Number 3, Part D, or the U.S. EPA has not relied on it in issuing a permit under Title I, Part C of the Federal Act, which permit is in effect when the increase in actual emissions from the particular change occurs; and

II.A.27.c.(iii) In order to establish a baseline emissions rate, the owner or operator must submit an Air Pollutant Emission Notice to the Division prior to the increase or decrease indicating actual emissions (as defined in Section II.A.1. of this of part) and the owner or operator must submit a revised Air Pollutant Emission Notice to the Division within one year after the increase or decrease occurs, or

II.A.27.c.(iv) The owner or operator provides credible, demonstrable evidence to the Division of what actual emissions were before making the increase or decrease and what they were after making the increase or decrease.

II.A.27.d. An increase or decrease in actual emissions of sulfur dioxide, particulate matter, or nitrogen oxides that occurs before the applicable minor source baseline date is creditable only if it is required to be considered in calculating the amount of maximum allowable increases remaining available. With respect to particulate matter, only PM10 emissions can be used to evaluate the net emissions increase for PM10 and only PM2.5 emissions can be used to evaluate the net emissions increase for PM2.5.

II.A.27.e. An increase in actual emissions is creditable only to the extent that the new level of actual emissions exceeds the old level.

II.A.27.f. A decrease in actual emissions is creditable only to the extent that:

II.A.27.f.(i) The Division has not relied on it in issuing any permit under this Part D, or has not relied on it in demonstrating attainment or reasonable further progress:

II.A.27.f.(ii) The old level of actual emissions or the old level of allowable emissions, whichever is lower, exceeds the new level of actual emissions;

II.A.27.f.(iii) It is enforceable as a practical matter at and after the time that actual construction on the particular change begins; and

II.A.27.f.(iv) It has approximately the same qualitative significance for public health and welfare as that attributed to the increase from the particular change; and

II.A.27.g. An increase that results from a physical change at a source occurs when the emissions unit on which construction occurred becomes operational and begins to emit a particular pollutant. Any replacement unit that requires shakedown becomes operational only after a reasonable shakedown period, not to exceed one hundred and eighty days.

II.A.27.h. Section II.A.1.a. of this part shall not apply for determining creditable increases and decreases after a change.

II.A.27.i. The organic compounds referenced in the common provisions definition of negligibly reactive volatile organic compounds are neither counted as reactive volatile organic compounds in determining significant ozone increases nor creditable against an increase in emissions of any volatile organic compound.

II.A.27.j. Creditable Decreases for Fuel Switching.

Generally, for credit to be given for the emissions reduction in potential to emit or actual emissions resulting from a physical change or change in method of operation of a major stationary source occurring on or after the effective date of this rule, an Air Pollutant Emission Notice reporting such reduction must be filed within one year after the reduction occurs unless an extension is requested by the source and approved by the Division due to uncertainty as to the permanence of such reduction. At the time credit for any reduction is requested, such reduction must be enforceable. Such reductions must be enforceable through permit conditions or source specific state implementation plan revisions.

II.A.28. Nonattainment Major New Source Review (NSR) Program

A major stationary source preconstruction permit program that has been approved by the Administrator and incorporated into this Regulation Number 3, Part D. Any permit issued under the program is a major NSR permit.

II.A.29. PAL Effective Date

Generally means the date of issuance of the PAL permit. However, the PAL effective date for an increased PAL is the date any emissions unit that is part of the PAL major modification becomes operational and begins to emit the PAL pollutant.

II.A.30. PAL Effective Period

The period beginning with the PAL effective date and ending ten years later.

II.A.31. PAL Major Modification

Notwithstanding Part A, Section I.B.44. and Part D Sections II.A.22 and II.A.26. (the definitions for subject to regulation, major modification, and net emissions increase), any physical change in or change in the method of operation of the PAL source that causes it to emit the PAL pollutant at a level equal to or greater than the PAL.

II.A.32. PAL Minor Source

Any stationary source that does not meet the definition of major stationary source in Part D, Section II.A.25. at the time the PAL is issued.

II.A.33. PAL Permit

The Operating Permit issued in accordance with this Part D that establishes a PAL for a major stationary source or a GHG-only source.

II.A.34. PAL Pollutant

The pollutant for which a PAL is established at a major stationary source or a GHG-only source. For a GHG-only source, the only available PAL pollutant is greenhouse gases.

II.A.35. Plant-wide Applicability Limitation (PAL)

An emission limitation expressed on a mass basis in tons per year, or expressed in tons per year CO2e for a CO2e-based GHG emission limitation, for a pollutant at a major stationary source or GHG-only source that is enforceable as a practical matter and established source-wide in accordance with Section XV. of this Part D.

II.A.36. Prevention of Significant Deterioration (PSD) Permit

Any permit that is issued in accordance with Section VI. of this Part D.

II.A.37. Project

A physical change in, or change in the method of operation of, an existing major stationary source.

II.A.38. Projected Actual Emissions

II.A.38.a. The maximum annual rate, in tons per year, at which an existing emissions unit at a major stationary source is projected to emit a regulated NSR pollutant in any one of the five years (twelve-month period) following the date the unit resumes regular operation after the project, or in any one of the ten years following that date, if the project involves increasing the emissions unit's design capacity or its potential to emit of that regulated NSR pollutant and full utilization of the unit would result in a significant emissions increase or a significant net emissions increase at the major stationary source.

II.A.38.b. In determining the projected actual emissions under Section II.A.38.a., above, before beginning actual construction, the owner or operator of the major stationary source:

II.A.38.b.(i) Shall consider all relevant information, including but not limited to, historical operational data, the company's own representations, the company's expected business activity and the company's highest projections of business activity, the company's filings with the State or Federal regulatory authorities, and compliance plans; and

II.A.38.b.(ii) Shall include fugitive emissions to the extent quantifiable, and emissions associated with startups, shutdowns, and malfunctions; and

II.A.38.b.(iii) Shall exclude, in calculating any increase in emissions that results from the particular project, that portion of the unit's emissions following the project that an existing unit could have accommodated during the consecutive twenty-four month period used to establish the baseline actual emissions under Section II.A.4. of this part D and that are also unrelated to the particular project, including any increased utilization due to product demand growth; or,

II.A.38.b.(iv) In lieu of using the method set out in Sections II.A.38.b.(i) through II.A.38.b.(iii), may elect to use the emissions unit's potential to emit, in tons per year, as defined in Section I.B.37. of Part A of this regulation.

II.A.39. Reactivation of Very Clean Coal-fired Electric Utility Steam Generating Unit

Any physical change or change in the method of operation associated with the commencement of commercial operations by a coal-fired utility unit after a period of discontinued operation where the unit:

II.A.39.a. Has not been in operation for the two year period prior to the enactment of the Clean Air Act Amendments of 1990, and the emissions from such unit continue to be carried in the permitting authority's emissions inventory at the time of the enactment;

II.A.39.b. Was equipped prior to shut-down with a continuous system of emissions control that achieves a removal efficiency for sulfur dioxide of no less than eighty-five percent and a removal efficiency for particulates of no less than ninety-eight percent;

II.A.39.c. Is equipped with low-nitrogen oxide burners prior to the time of commencement of operations following reactivation; and

II.A.39.d. Is otherwise in compliance with the requirements of the Federal Act.

II.A.40. Regulated NSR Pollutant

II.A.40.a. Nitrogen oxides or any volatile organic compound;

II.A.40.b. Any pollutant for which a national ambient air quality standard has been promulgated;

II.A.40.c. Any pollutant that is a constituent or precursor of a general pollutant listed under Sections II.A.40.a. or II.A.40.b., above,(e.g. volatile organic compounds and oxides of nitrogen are precursors for ozone) provided that such a constituent or precursor pollutant may only be regulated under NSR as part of regulation of the general pollutant. Precursors for the purposes of New Source Review are the following:

II.A.40.c.(i) Nitrogen oxides or any volatile organic compound are precursors to ozone;

II.A.40.c.(ii) Sulfur dioxide is a precursor to PM2.5;

II.A.40.c.(iii) Nitrogen oxides are precursors to PM2.5.

II.A.40.d. Any pollutant, except for GHG, that is subject to ny standard promulgated under Section 111 of the Federal Act, (see II.A.40.e. for GHG);

II.A.40.e. Any pollutant that otherwise is subject to regulation under the Federal Act as defined in Section I.B.44. or Part A;

II.A.40.f. Notwithstanding Sections II.A.40.a. through II.A.40.e. of this Part D, the term regulated NSR pollutant shall not include any or all hazardous air pollutants either listed in Section 112 of the Federal Act (that have not been delisted pursuant to Section 112(b)(3) of the Federal Act) or Appendix B of this regulation, unless the listed hazardous air pollutant is also regulated as a constituent or precursor of a general pollutant listed under Section 108 of the Federal Act.

II.A.40.g. PM2.5 emissions and PM10 emissions shall include gaseous emissions from a source or activity which condense to form particulate matter at ambient temperatures. On or after January 1, 2011, such condensable particulate matter shall be accounted for in applicability determinations and in establishing emissions limitations for PM2.5 and PM10 in PSD permits. Compliance with emission limitations for PM2.5 and PM10 issued prior to this date shall not be based on condensable particulate matter unless required by the terms and conditions of the permit or the applicable implementation plan. Applicability determinations made prior to this date without accounting for condensable particulate matter shall not be considered in violation of this section.

II.A.41. Replacement Unit

An emissions unit for which all the criteria listed in Sections II.A.41.a. through II.A.41.d. are met. No creditable emission reductions shall be generated from shutting down the existing emissions unit that is replaced.

II.A.41.a. The emissions unit is a reconstructed unit within the meaning of Code of Federal Regulations Title 40, Section 60.15(b)(1), or the emissions unit completely takes the place of an existing emissions unit.

II.A.41.b. The emissions unit is identical to or functionally equivalent to the replaced emissions unit.

II.A.41.c. The replacement does not alter the basic design parameters of the process unit.

II.A.41.d. The replaced emissions unit is permanently removed from the major stationary source, otherwise permanently disabled, or permanently barred from operation by a permit that is enforceable as a practical matter. If the replaced emissions unit is brought back into operation, it shall constitute a new emissions unit.

II.A.42. Repowering

II.A.42.a. Replacement of an existing coal-fired boiler with one of the following clean coal technologies: atmospheric or pressurized fluidized bed combustion, integrated gasification combined cycle, magnetohydrodynamics, direct and indirect coal-fired turbines, integrated gasification fuel cells, or as determined by the Administrator, in consultation with the Secretary of Energy, a derivative of one or more of these technologies, and any other technology capable of controlling multiple combustion emissions simultaneously with improved boiler or generation efficiency and with significantly greater waste reduction relative to the performance of technology in widespread commercial use as of November 15, 1990.

II.A.42.b. Repowering shall also include any oil and/or gas-fired unit that have been awarded clean coal technology demonstration funding as of January 1, 1991, by the Department of Energy.

II.A.43. Secondary Emissions

Emissions that occur as a result of the construction or operation of a major stationary source or major modification, but do not come from the major stationary source or major modification itself. For the purpose of this Part D, secondary emissions must be specific, well defined, quantifiable, and impact the same general area as the stationary source or modification that causes the secondary emissions. Secondary emissions include emissions from any offsite support facility that would not otherwise be constructed or increase its emissions except as a result of the construction or operation of the major stationary source or major modification. Secondary emissions do not include any emissions that come directly from a mobile source, such as emissions from the tailpipe of a motor vehicle, from a train, or from a vessel.

II.A.44. Significant

II.A.44.a. Unless the context otherwise requires, a significant rate of emissions in tons per year is defined as a value that would equal or exceed any of the following:

Carbon monoxide: 100 tons per year

Nitrogen Oxides: 40 (nitric oxide + nitrogen dioxide) tons per year

Sulfur dioxide: 40 tons per year

Particulate matter: 25 tons per year particulate matter emissions or, 15 tons per year of PM10 emissions

PM10 - Precursors in the Denver Metropolitan PM10 attainment/maintenance area: 40 tons per year for each individual precursor (nitrogen oxides or sulfur oxides)

PM2.5: 10 tons per year of direct PM2.5 emissions; 40 tons per year of sulfur dioxide emissions; or 40 tons per year of nitrogen dioxide emissions

Ozone: 40 tons per year of volatile organic compounds or nitrogen oxides

Lead: 0.6 tons per year

Fluorides: 3 tons per year

Sulfuric acid mist: 7 tons per year

Hydrogen sulfide: 10 tons per year

Total reduced sulfur (including hydrogen sulfide): 10 tons per year

Reduced sulfur compounds (including hydrogen sulfide): 10 tons per year

Municipal Waste Combustor Organics (measured as total tetra- through octa-chlorinated dibenzo-p-dioxins and dibenzofurans): 3.2 x 10-6 megagrams per year (3.5 x 10-6 tons per year)

Municipal Waste Combustor Metals (measured as particulate matter): 14 megagrams per year (15 tons per year)

Municipal Waste Combustor Acid Gases (measured as sulfur dioxide and hydrogen chloride): 36 megagrams per year (40 tons per year)

Municipal Solid Waste Landfill Gases (measured as non-methane organic compounds): 45 megagrams per year (50 tons per year)

In a serious or severe ozone nonattainment area: 25 tons per year of volatile organic compounds or nitrogen oxides

In an extreme ozone nonattainment area: any increase of volatile organic compounds or nitrogen oxides

II.A.44.b. Significant means, in reference to a net emissions increase or the potential of a source to emit a regulated NSR pollutant that this definition does not list, any emissions rate, except that this definition shall not apply to hazardous air pollutants listed in or pursuant to Section 112 of the Federal Act.

II.A.44.c. Notwithstanding the significant emission rates above, significant means any emissions rate or any net emissions increase associated with a major stationary source or major modification, that would construct within ten kilometers of a Class I area, and have an impact on such area equal to or greater than one microgram/cubic meter ((g/m3 ) (twenty-four hour average).

II.A.45. Significant Emissions Increase

For a regulated NSR pollutant, an increase in emissions that is significant (as defined in Section II.A.44. of this Part D) for that pollutant.

II.A.46. Significant Emissions Unit

II.A.46.a. An emissions unit that emits or has the potential to emit a PAL pollutant in an amount that is equal to or greater than the significant level (as defined in Section II.A.44. of this Part D or in the Federal Act, whichever is lower) for that PAL pollutant, but less than the amount that would qualify the unit as a major emissions unit (as defined in Section II.A.22. of this part).

II.A.46.b. For a GHG PAL issued on a CO2e basis, significant emissions unit means any emissions unit that emits or has the potential to emit GHGs on a CO2e basis in amounts equal to or greater than the amount that would qualify the unit as small emissions unit as defined in Section II.A.47, but less than the amount that would qualify the unit as a major emissions unit as defined in Section II.A.22.

II.A.47. Small Emissions Unit

II.A.47.a. An emissions unit that emits or has the potential to emit the PAL pollutant in an amount less than the significant level for that PAL pollutant (as defined in Section II.A.34. of this Part D or in the Federal Act, whichever is lower).

II.A.47.b. For a GHG PAL issued on a CO2e basis, small emissions unit means an emissions unit less than the amount of GHGs on a CO2e basis defined as significant for the purposes of Part A, Section I.B.46.c. at the time the PAL permit is being issued.

II.A.48. Temporary Clean Coal Technology Demonstration Project

A clean coal technology demonstration project that is operated for a period of five years or less, and that complies with the state implementation plan and other requirements necessary to attain and maintain the National Ambient Air Quality Standards during the project and after it is terminated.

## III. Permit Review Procedures

III.A. Major stationary sources subject to the requirements of this Part D must apply for and obtain a Construction Permit in accordance with the procedures and requirements in Part B or an Operating permit in accordance with the procedures and requirements in Part C.

III.B. The Division shall complete the processing of applications (including any requested public hearing) for sources subject Sections VI. and VII. of this Part D within twelve months of receipt of a complete application.

## IV. Public Comment Requirements

IV.A. When public comment is required, or when the Division determines that an application warrants public comment in accordance with Section III.C.3. of Part B of this regulation, the Division shall, within fifteen calendar days after the preparation of the preliminary analysis, cause public notice of the application to be published in a newspaper of general distribution in the area in which the proposed project or activity is or will be located, and by such other means as necessary to assure notice to the affected public, which may include posting of such notice on the publicly accessible portion of the Division's web site, and cause a copy of the application, the preliminary analysis and the draft permit to be filed with the county clerk for each county in which the source is, or will be, located. The Division shall send written or electronic notice to persons requesting a notice of permit applications for the type of source or geographic area.

IV.A.1. For sources subject to the provisions of Sections V. and VI. of this part, a copy of all the materials the applicant submitted, and a copy or summary of other materials, if any, considered in making the preliminary analysis shall be filed with the county clerk for each county in which the source is or will be located. In addition, for sources subject to the provisions of Sections V. and VI., a copy of the written or electronic notice of public comment shall be sent to the applicant, the U.S. EPA Administrator, and to officials and agencies having cognizance over the location where the proposed construction would occur, including any other state or local air pollution control agencies and any state, Indian governing body or Federal Land Manager whose lands may be affected by emissions from the source or modification.

IV.A.2. Additionally, for permit applications subject to the requirements of this Part D, the notice shall contain the following information:

IV.A.2.a. That comments are solicited on an innovative technological system for pollution control if proposed by the applicant and that a hearing by the Commission will be held on such system if requested by any interested person;

IV.A.2.b. That comments are solicited on the air quality impacts of the source or modification;

IV.A.2.c. That comments are solicited on alternatives to the source or modification;

IV.A.2.d. That any interested person may submit a written request for a public comment hearing to be held pursuant to Section VII. of the Commission's Procedural Rules to receive comments regarding the foregoing concerns, the sufficiency of the preliminary analysis, and whether the Division should approve or deny the permit application; and

IV.A.2.e. The degree of increment consumption that is expected from the source or modification.

IV.A.3. Within fifteen calendar days after the preparation of the preliminary analysis for those applications subject to the requirements of this Part D, the Division shall forward to the applicant written notice of the applicant's right to a public comment hearing with respect to the application pursuant to Section VII. of the Commission's Procedural Rules.

IV.A.4. A hearing request pursuant to Section IV.A.2.a. of this Part D, regarding innovative control, must be transmitted by the Division to the Commission within twenty days after its receipt.

IV.A.5. A hearing request pursuant to Section IV.A.2.d. of this Part D must be transmitted by the Division to the Commission, along with the complete permit application, the preliminary analysis, the draft permit, and any written comments received by the Division within five days after the end of the thirty-day comment period. At least thirty days prior to the date set for the public comment hearing, the notice of public comment hearing, the preliminary analysis and the draft permit shall be posted on the Division's web site. No substantive revisions shall be made to the draft permit during the thirty days prior to the public comment hearing.

IV.A.6. The Commission shall hold a public comment hearing within sixty days of its receipt of the request for such hearing pursuant to Section IV.A.2. of this Part D (unless such greater time is agreed to by the applicant and the Division), but at least sixty days after receipt by any Federal Land Manager of notice and the permit application required pursuant to Section XIII.A. of this Part D. The Division shall appear at the public comment hearing in order to present the permit application. At least thirty days prior to such hearing, notice thereof shall be mailed by the Commission to the applicant, to any interested person who submitted a request for a public hearing and to any Federal Land Manager given notice pursuant to Section XIII.A., printed in a newspaper of general distribution in the area of the proposed source or modification, and submitted for public review with the county clerk for each county in which the source or modification is or will be located. Except as provided herein and in the notice, such hearings will be conducted pursuant to the Act, the Procedural Rules of the Air Quality Control Commission and the State Administrative Procedure Act, Colorado Revised Statutes, Section 24-4-101 et seq.

IV.A.7. Within fifteen days after the Division makes a final decision on an application subject to the requirements of this Part D, the Division shall make available for public inspection the decision and all public comments with the county clerk for each county where the pre-construction information was made available.

## V. Requirements Applicable to Nonattainment Areas

V.A. Major Stationary Sources.

For any new major stationary source or major modification, the Division shall grant a permit if it determines that the following conditions in Sections V.A.1. through V.A.6., as well as those in Section III.D.1. of Part B of this regulation, will be met:

V.A.1. The proposed source will achieve the lowest achievable emission rate for the specific source category.

V.A.2. The applicant has certified that all other existing major stationary sources owned, operated, or controlled by the applicant (or any entity controlling, controlled by, or under the common control with the applicant) in Colorado are in compliance with the requirements of the State implementation plan and the federally approved state implementation plan, or are subject to and in compliance with an enforceable compliance schedule, or a federally enforceable compliance schedule.

V.A.3. Prior to the date of commencement of operations, the ratio of total actual emission reductions compared to the emissions increase (offsets) shall be at least one for one (1:1), unless an alternative ratio is provided for the applicable nonattainment area as identified in Section V.A.3.a., below.

V.A.3.a. Offset Ratios

V.A.3.a(i) For ozone nonattainment areas that are subject to subpart 2, part D, title I of the Federal Act, the offset ratio of total actual emission reductions of VOC to the emissions increase of VOC shall be as follows:

V.A.3.a(i)(a) In any marginal nonattainment area for ozone – at least 1.1:1;

V.A.3.a(i)(b) In any moderate nonattainment area for ozone – at least 1.15:1;

V.A.3.a(i)(c) In any serious nonattainment area for ozone – at least 1.2:1;

V.A.3.a(i)(d) In any severe nonattainment area for ozone – at least 1.3:1; or

V.A.3.a(i)(e) In any extreme nonattainment area for ozone – at least 1.5:1.

V.A.3.a.(ii) For all areas within an ozone transport region that is subject to subpart 2, part D, title 1 of the Federal Act, and that are not designated as serious, severe or extreme and are subject to subpart 1, part D, title 1 of the Federal Act – at least 1.15:1.

V.A.3.a.(iii) For ozone nonattainment areas that are subject to subpart 1, part D, title I of the Federal Act, including 8-hour ozone nonattainment areas subject to 40 CFR, Part 51, Section 51.902(b), the ratio of total actual emissions reductions of VOC to the emissions increase of VOC shall be at least 1:1.

V.A.3.b. Offsets must be obtained from existing sources (whether or not under the same ownership) within the nonattainment area for each pollutant, or its precursors, for which the area is nonattainment. Offsets must represent reasonable further progress towards attainment of the National Ambient Air Quality Standards when considered in connection with other new and existing sources of emissions. In addition, offsets for PM10, PM2.5, sulfur oxides, and carbon monoxide must show, through atmospheric modeling, a positive net air quality benefit in the area affected by the emissions. Provided, however, that offsets meeting the requirements of this Section V.A.3. may also be obtained from existing sources outside the nonattainment area if the applicant demonstrates:

V.A.3.b.(i) A greater air quality benefit may thus be achieved, or sufficient offsets are not available from sources within the nonattainment area; and

V.A.3.b.(ii) The other area has an equal or higher nonattainment classification than the area in which the source is located; and

V.A.3.b.(iii) Emissions from such other area contribute to a violation of the National Ambient Air Quality Standard in the nonattainment area in which the source is located.

V.A.3.b.(iv) With respect to offsets obtained from outside the nonattainment area, the Division may increase the ratio of the required offsets to new emissions the greater the distance such offsets are from the new or modified source.

V.A.3.c. Offsets must be for the same regulated NSR pollutant, except that offset requirements for direct PM2.5 emissions or PM2.5 precursors may be satisfied by offsetting reductions in direct PM2.5 emissions or emissions of any PM2.5 precursor identified under Section II.A.40. of Part D.

V.A.4. The permit application shall include an analysis of alternative sites, sizes, production processes and environmental control techniques for such proposed source that demonstrates that benefits of the proposed source significantly outweigh the environmental and social costs imposed as a result of its location, construction, or modification.

V.A.5. Offsets for which emission reduction credit is taken must be enforceable through permit conditions or source specific state implementation plan revisions.

V.A.6. The applicant will demonstrate that emissions from the proposed source will not adversely impact visibility in a Class I area. This demonstration shall be reviewed by the Federal Land Manager and any determination made by the Federal Land Manager shall be considered in the Division's decision to grant the permit. If an adverse impact, as described in Section XIV.E., is predicted by the Division, the permit application will be denied. Federal Land Manager involvement shall follow the same procedures as stated in Section XIII.A. of this Part D. The demonstration will be performed using either techniques described in the latest version of the U.S. EPA document entitled “Workbook for Estimating Visibility Impairment” or other techniques approved by the Division.

V.A.7. Applicability of Certain Nonattainment Area Requirements

V.A.7.a. Any major stationary source in a nonattainment area is subject to the requirements of Section V.A. of this Part D.

V.A.7.b. The requirements of Section V.A. shall apply at such time that any stationary source or modification becomes a major stationary source or major modification solely by virtue of a relaxation in any enforceable limitation that was established after August 7, 1980 on the capacity of the source or modification to otherwise emit a pollutant, such as a restriction on hours of operation.

V.A.7.c. The following provisions apply to projects at existing emissions units at a major stationary source (other than projects at a source with a PAL) in circumstances where there is a project that is not a part of a major modification and the owner or operator elects to use the method specified in Sections II.A.38.b.(i) through II.A.38.b.(iii) of this Part D for calculating projected actual emissions.

V.A.7.c.(i) Before beginning actual construction of the project, the owner or operator shall document and maintain a record of the following information:

V.A.7.c.(i)(A) A description of the project;

V.A.7.c.(i)(B) Identification of the emissions unit(s) whose emissions of a regulated NSR pollutant could be affected by the project; and

V.A.7.c.(i)(C) A description of the applicability test used to determine that the project is not a major modification for any regulated NSR pollutant, including the baseline actual emissions, the projected actual emissions, the amount of emissions excluded under Section II.A.38.b.(iii) of this part and an explanation for why such amount was excluded, and any netting calculations, if applicable.

V.A.7.c.(ii) If the emissions unit is an existing electric utility steam generating unit, before beginning actual construction, the owner or operator shall provide a copy of the information set out in Section V.A.7.c.(i) to the Division. Nothing in this Section V.A.7.c.(ii) shall be construed to require the owner or operator of such a unit to obtain any determination from the Division before beginning actual construction.

V.A.7.c.(iii) The owner or operator shall monitor the emissions of any regulated NSR pollutant that could increase as a result of the project and that is emitted by any emissions units identified in Section V.A.7.c.(i)(B); and calculate and maintain a record of the annual emissions, in tons per year on a calendar year basis, for a period of five years following resumption of regular operations after the change, or for a period of ten years following resumption of regular operations after the change if the project increases the design capacity or potential to emit of that regulated NSR pollutant at such emissions unit.

V.A.7.c.(iv) If the unit is an existing electric utility steam generating unit, the owner or operator shall submit a report to the Division within sixty days after the end of each year during which records must be generated under Section V.A.7.c.(iii) setting out the unit's annual emissions during the calendar year that preceded submission of the report.

V.A.7.c.(v) If the unit is an existing unit other than an electric utility steam generating unit, the owner or operator shall submit a report to the Division if the annual emissions, in tons per year, from the project identified in Section V.A.7.c.(i), exceed the baseline actual emissions (as documented and maintained pursuant to Section V.A.7.c.(i)(C)) by a significant amount (as defined in Section II.A.44. of this part) for that regulated NSR pollutant, and if such emissions differ from the preconstruction projection as documented and maintained pursuant to Section V.A.7.c.(i)(C). Such report shall be submitted to the Division within sixty days after the end of such year. The report shall contain the following:

V.A.7.c.(v)(A) The name, address and telephone number of owner or operator of the major stationary source;

V.A.7.c.(v)(B) The annual emissions as calculated pursuant to Section V.A.7.c.(iii); and

V.A.7.c.(v)(C) Any other information that the owner or operator wishes to include in the report (e.g., an explanation as to why the emissions differ from the preconstruction projection).

V.A.7.d. The owner or operator of the source shall make the information required to be documented and maintained pursuant to Section V.A.7.c. available for review upon request for inspection by the Division or the general public.

V.A.8. Exemptions from certain nonattainment area requirements:

V.A.8.a. The following are exempt from the major stationary source criteria of Section V.A.3. of this part.

V.A.8.a.(i)(A) Portable sources that will relocate outside a nonattainment area in less than one year.

V.A.8.a.(i)(B) Each pilot plant that operates an aggregate of less than six months.

V.A.8.a.(i)(C) Construction phases of a new or modified building, facility, structure, or installation. These may, at the discretion of the Division, exceed a period of one year.

V.A.8.a.(i)(D) Other temporary processes or activities of less than one year in duration.

V.A.8.a.(i)(E) Sources undergoing fuel switches as required by federal order if the Division determines that:

V.A.8.a.i(E)(1) The applicant has used best efforts in seeking the required emission offsets but was unsuccessful;

V.A.8.a.i(E)(2) All available emission offsets were obtained; and,

V.A.8.a.i(E)(3) The applicant will continue to seek emission offsets as they become available.

**VI. Requirements applicable to attainment and unclassifiable areas and pollutants implemented under Section 110 of the Federal Act (Prevention of Significant Deterioration Program).**

VI.A. Major Stationary Sources and Major Modifications.

The requirements of this Section VI. shall apply to any major stationary source and any major modification with respect to each pollutant regulated under the Act and the Federal Act that it would emit, except as this Regulation Number 3 would otherwise allow.

For any new major stationary source or major modification proposing to construct in any area in Colorado designated under Section 107 (d) of the Federal Act as attainment or unclassifiable for any criteria pollutant as of the date of submittal of a complete application under this Regulation Number 3, or for pollutants implemented under Section 110 of the Federal Act, the Division shall grant a permit if it determines that the following requirements, in addition to those in Section III.D.1. of Part B of this regulation, have been or will be met:

VI.A.1. Control Technology Review.

VI.A.1.a. A new major stationary source shall apply Best Available Control Technology for each pollutant regulated under the Act or Federal Act that it would have the potential to emit in significant amounts.

VI.A.1.b. A major modification shall apply best available control technology for each pollutant regulated under the Act or Federal Act for which there would be a significant net emissions increase at the source. This requirement applies to each proposed emissions unit at which a net emissions increase in the pollutant would occur as a result of a physical change or change in the method of operation of the unit.

VI.A.1.c. For phased construction projects, the determination of best available control technology shall be reviewed and modified as appropriate at the latest reasonable time which occurs no later than eighteen months prior to commencement of construction of each independent phase of the project. The review will be conducted in a timely manner that will allow the owner or operator to proceed with scheduled construction of the source. During the review, the owner or operator of the applicable stationary source may be required to demonstrate the adequacy of any previous determination of best available control technology for the source.

VI.A.2. Source Impact Analysis. The owner or operator of the proposed source or modification shall demonstrate to the Division that allowable emission increases from the proposed source or modification in conjunction with all other applicable emissions increases or reductions (including secondary emissions) will not cause or contribute to concentrations of air pollutants in the ambient air in violation of either Section VI.A.2.a. or b.

VI.A.2.a. Any state or national ambient air quality standard in any baseline area or air quality control region; or

VI.A.2.b. Any applicable maximum allowable increase over the baseline concentration in any area.

VI.A.2.c. Reserved

VI.A.3. Pre-construction Monitoring and Analysis

VI.A.3.a. An analysis of ambient air quality in any area that would be affected by the proposed major stationary source or major modification shall be performed for each pollutant regulated under the Act or Federal Act that the source or modification would emit or have the potential to emit in a significant amount, or for which there would be a significant net emissions increase.

VI.A.3.b. With respect to any such regulated pollutant for which no national ambient air quality standard exists and for which there is an acceptable method for the monitoring of that pollutant, the analysis shall contain such air quality monitoring data as the Division determines are necessary to assess ambient air quality for that pollutant in any area that emissions of that pollutant would affect.

VI.A.3.c. With respect to any such pollutant for which a national ambient air quality standard does exist, the analysis shall contain continuous air quality monitoring data gathered for purposes of determining whether emissions of that pollutant would cause or contribute to a violation of the applicable standard or any maximum allowable increase.

VI.A.3.d. In general, the continuous air quality monitoring data that are required under Section VI.A.3.c., or the pre-application monitoring of air quality related values required by Section XIII.B. of this part, shall have been gathered over a period of one year and shall represent the year preceding receipt of the application, except that, if the Division determines that a complete and adequate analysis can be accomplished with monitoring data gathered over a period shorter than one year (but not to be less than four months), the data that are required shall have been gathered over at least that shorter period.

VI.A.3.e. The owner or operator of a proposed major stationary source or major modification of volatile organic compounds who satisfies all conditions of the Code of Federal Regulations Title 40, Part 51, Appendix S, Section IV. (but not including conditions resulting from amendments after July 1, 1991 and not including Section IV. B. of Appendix S) may provide post-approval monitoring data for ozone in lieu of providing pre-construction data as required under Section VI.A.3.a. (Information on obtaining the Code of Federal Regulations Title 40, Part 51, Appendix S, Section IV. is available from the Director, Air Pollution Control Division, 4300 Cherry Creek Drive South, Denver, Colorado, 80246-1530.)

VI.A.4. Post-Construction Monitoring. At its discretion, the Division may require that the owner or operator of a major stationary source or major modification conduct post-construction ambient monitoring for a period up to one year. The Division may also require additional monitoring beyond the one year period if such monitoring is necessary to determine the effect emissions from the stationary source or modification have, or may have, on air quality in any area. The monitoring of air quality related values or sensitive receptors required by Section XIII.B. of this part, shall be for such time as is necessary to determine the effect emissions from the source or modification will have on the air quality related values or sensitive receptors.

Post-construction monitoring requirements will be permit conditions.

VI.A.5. Operation of Monitoring Stations. The owner or operator of a major stationary source or major modification shall use the U.S. EPA accepted procedures for ambient monitoring as approved by the Division during the operation of monitoring stations for purposes of satisfying the requirements of Sections VI.A.3. and VI.A.4., above.

VI.A.6. Additional Impact Analysis. For each pollutant that is regulated under the Act or the Federal Act, and for which the source or modification would emit in significant amounts (as defined in Section II.A.44. of this part) or for which there would be a significant net emissions increase, the owner or operator shall provide an analysis of the impairment to visibility, water, soils, and vegetation that would occur as a result of the emissions of such pollutant from the source or modification and general commercial, residential, industrial, and other growth associated with the source or modification. The analysis of impairment to water will not be used in the determination of best available control technology. The owner or operator need not provide an analysis of the impact on vegetation having no significant commercial or recreational value. The additional impact analysis will include the effects on air quality related values as stated in Section XIII.B. of this part, if applicable.

The owner or operator shall provide an analysis of the air quality impact projected for the area as a result of general commercial, residential, industrial and other growth associated with the source or modification.

VI.B. Applicability of Certain PSD Requirements.

VI.B.1. The requirements of Section VI.A. do not apply to a major stationary source or major modification with respect to a particular pollutant if the owner or operator demonstrates that, as to that pollutant:

VI.B.1.a. The source or modification is subject to Part 3 of the Act and Section V. of this part, and the source or modification would not impact any area designated as attainment or unclassifiable for that pollutant; or

VI.B.1.b. The emissions from the source or modification would not be significant; or

VI.B.1.c. The source or modification is a portable stationary source that has previously received a permit under requirements equivalent to those contained in Section VI.A. of this part if:

VI.B.1.c.(i) The source proposes to relocate and emissions of the source at the new location would be temporary;

VI.B.1.c.(ii) The emissions from the source would not exceed its allowable emissions;

VI.B.1.c.(iii) The emissions from the source would impact no Class I area and no area where an applicable increment is known to be violated; and

VI.B.1.c.(iv) Reasonable notice identifying the proposed new location and the probable duration of operation at the new location and a revised Air Pollutant Emission Notice is given to the Division prior to the relocation. Such notice and revised Air Pollutant Emission Notice shall be given to the Division not less than ten days in advance of the proposed relocation unless a different time duration is previously approved by the Division.

VI.B.2. The requirements contained in Sections VI.A.2. through VI.A.4. of this part do not apply:

VI.B.2.a. To a proposed major stationary source or major modification with respect to a particular pollutant, if the emissions would be from a temporary source, modification or activity, such as construction or exploration, and would not have an impact on air quality in any Class I area or an area where an applicable increment is known to be violated; or

VI.B.2.b. As they relate to any maximum allowable increase for a Class II area, to a modification of a major stationary source that was in existence on March 1, 1978, if the net increase in allowable emissions of each pollutant subject to regulation, excluding GHG, under the Act from the modification after the application of best available control technology would be less than fifty tons per year.

VI.B.3. The Division may exempt a proposed major stationary source or major modification from the requirements of Sections VI.A.3. through VI.A.5. of this part, with respect to monitoring for a particular pollutant if:

VI.B.3.a. The emissions of the pollutant from the new stationary source or the net emissions increase of the pollutant from the modification would cause air quality impacts, in any area, less than the following:

VI.B.3.a.(i) Carbon monoxide - 575 µg/$m^3$, 8-hour average;

VI.B.3.a.(ii) Nitrogen dioxide - 14 µg/$m^3$, annual average;

VI.B.3.a.(iii) Particulate Matter - PM10 -- 10 µg/$m^3$, 24-hour average; PM2.5 – 0 µg/$m^3$, 24-hour average;

VI.B.3.a.(iv) Sulfur dioxide - 13 µg/$m^3$, 24-hour average;

VI.B.3.a.(v) Lead - 0.1 µg/$m^3$, 3-month average;

VI.B.3.a.(vi) Fluorides - 0.25 µg/$m^3$, 24-hour average;

VI.B.3.a.(vii) Total reduced sulfur - 10 µg/$m^3$, 1-hour average;

VI.B.3.a.(viii) Hydrogen sulfide - 0.2 µg/$m^3$, 1-hour average;

VI.B.3.a.(ix) Reduced sulfur compounds - 10 µg/$m^3$, 1-hour average; or

VI.B.3.b. The existing concentrations of the pollutant in the area that the source or modification would affect are less than the concentrations listed in this section; or

VI.B.3.c. For ozone, the emissions increase or net emissions increase of volatile organic compounds or nitrogen oxides from the source or modification would be less than 100 tons per year; or

VI.B.3.d. The pollutant is not referred to in this Section VI.B.3.a.; or

VI.B.3.e. The source or modification was subject to Section VI., with respect to PM2.5, as in effect before July 15, 2008, and the owner or operator submitted an application for a permit under this Section VI.A. of Part D before that date consistent with EPA recommendations to use PM10 as a surrogate for PM2.5, and the Division subsequently determines that the application as submitted was complete with respect to the PM2.5 requirements then in effect, as interpreted by EPA in the memorandum entitled “Interim Implementation of New Source Review Requirements for PM2.5” (October 23, 1997). Instead, the requirements of Section VI.A. of this Part D, as interpreted in the aforementioned memorandum, that was in effect before July 15, 2008 shall apply to such source or modification.

VI.B.4. The requirements of this Part D shall apply at such time that any stationary source or modification becomes a major stationary source or major modification solely by virtue of a relaxation in any enforceable limitation that was established after August 7, 1980, on the capacity of the source or modification to otherwise emit a pollutant such as a restriction on hours of operation.

VI.B.5. The following provisions apply to projects at existing emissions units at a major stationary source (other than projects at a source with a PAL) in circumstances where there is a project that is not a part of a major modification and the owner or operator elects to use the method specified in Sections II.A.38.b.(i) through II.A.38.b.(iii) of this Part D for calculating projected actual emissions.

VI.B.5.a. Before beginning actual construction of the project, the owner or operator shall document and maintain a record of the following information:

VI.B.5.a.(i) A description of the project;

VI.B.5.a.(ii) Identification of the emissions unit(s) whose emissions of a regulated NSR pollutant could be affected by the project; and

VI.B.5.a.(iii) A description of the applicability test used to determine that the project is not a major modification for any regulated NSR pollutant, including the baseline actual emissions, the projected actual emissions, the amount of emissions excluded under Section II.A.38.b.(iii) of this part, and an explanation for why such amount was excluded, and any netting calculations, if applicable.

VI.B.5.b. If the emissions unit is an existing electric utility steam-generating unit, before beginning actual construction, the owner or operator shall provide a copy of the information set out in Section VI.B.5.a. to the Division. Nothing in this Section VI.B.5.b. shall be construed to require the owner or operator of such a unit to obtain any determination from the Division before beginning actual construction.

VI.B.5.c. The owner or operator shall monitor the emissions of any regulated NSR pollutant that could increase as a result of the project and that is emitted by any emissions unit identified in Section VI.B.5.a.(ii); and calculate and maintain a record of the annual emissions, in tons per year on a calendar year basis, for a period of five years following resumption of regular operations after the change, or for a period of ten years following resumption of regular operations after the change if the project increases the design capacity or potential to emit of that regulated NSR pollutant at such emissions unit.

VI.B.5.d. If the unit is an existing electric utility steam generating unit, the owner or operator shall submit a report to the Division within sixty days after the end of each year during which records must be generated under Section VI.B.5.c. setting out the unit's annual emissions during the calendar year that preceded submission of the report.

VI.B.5.e. If the unit is an existing unit other than an electric utility steam-generating unit, the owner or operator shall submit a report to the Division if the annual emissions, in tons per year, from the project identified in Section VI.B.5.a. exceed the baseline actual emissions (as documented and maintained pursuant to Section VI.B.5.a.(iii)) by a significant amount (as defined in Section II.A.44. of this part) for that regulated NSR pollutant, and if such emissions differ from the preconstruction projection as documented and maintained pursuant to Section VI.B.5.a.(iii). Such report shall be submitted to the Division within sixty days after the end of such year. The report shall contain the following:

VI.B.5.e.(i) The name, address and telephone number of the major stationary source;

VI.B.5.e.(ii) The annual emissions as calculated pursuant to Section VI.B.5.c.; and

VI.B.5.e.(iii) Any other information that the owner or operator wishes to include in the report (e.g., an explanation as to why the emissions differ from the preconstruction projection).

VI.B.6. The owner or operator of the source shall make the information required to be documented and maintained pursuant to Section VI.B.5. available for review upon request for inspection by the Division or the general public.

VI.B.7. A stationary source or modification may apply the applicable maximum allowable increases for total suspended particulate matter as in effect on the date of the permit application, in meeting the requirements of Section VI.A.2. of this part, if the following requirements are met:

VI.B.7.a. The owner or operator of the source or modification submitted an application for a permit under Regulation Number 3 before the provisions for maximum allowable increases for PM10 took effect; and

VI.B.7.b. The Division determines that the application as submitted, before the date that the maximum allowable increases for PM10 took effect, was complete.

VI.C. Notice to the U.S. EPA.

The Division shall transmit to the Administrator of the U. S. EPA a copy of each permit application relating to a major stationary source or major modification subject to this regulation, and provide notice of every action related to the consideration of such permit.

VI.D. Major Stationary Sources in attainment areas affecting nonattainment areas.

VI.D.1. For any new major stationary source or major modification that is proposed to be constructed in an area designated under Section 107(d) of the Federal Act as attainment or unclassifiable for a particular pollutant and the emissions of such pollutant from which would significantly affect ambient air quality in an area designated as nonattainment for such pollutant, the Division shall grant a permit if it determines that one or both of the following conditions, as well as those in Section III.D.1. of Part B and Section VI.A. of this Part D will be met:

VI.D.1.a. The proposed source or modification will meet the requirements of Sections V.A.1. and V.A.2. of this part, and obtain sufficient emission reductions of such pollutant in the nonattainment area to offset that portion of its emissions of such pollutant that affect the nonattainment area. Offsets may be obtained from outside the nonattainment area as provided in Section V.A.3. of this part; or

VI.D.1.b. The proposed source or modification will achieve an emissions rate that will ensure that the emissions of such pollutant from the source or modification will not significantly affect ambient air quality in the nonattainment area.

VI.D.2. Ambient air quality will be deemed to be significantly affected if, but for any offsets, the applicable significance level set forth in the following table would be exceeded in the nonattainment area.

TABLE OF SIGNIFICANCE LEVELS

| **Pollutant** | **Averaging Time** | | | | |
|---|---|---|---|---|---|
| | **Annual** | **24-Hour** | **8-Hour** | **3-Hour** | **1-Hour** |
| $SO_2$ | 1.0 µg/m$^3$ | 5 µg/m$^3$ | | 25 µg/m$^3$ | |
| PM10 | 1.0 µg/m$^3$ | 5 µg/m$^3$ | | | |
| PM2.5 | 0.3 µg/m$^3$ | 1.2 µg/m$^3$ | | | |
| $NO_2$ | 1.0 µg/m$^3$ | | | | |
| CO | | | 500 µg/m$^3$ | | 2000 µg/m$^3$ |

VI.D.3. Any new major stationary source or major modification subject to this section that will emit or cause a net emissions increase in volatile organic compounds or oxides of nitrogen shall demonstrate to the satisfaction of the Division that its emissions will not affect any ozone nonattainment area or shall obtain offsets as required in Section VI.D.1., above.

VI.D.4. Emission offsets for PM10, sulfur dioxide, and carbon monoxide, must show, through air quality modeling, a positive net air quality benefit in the portion of the nonattainment area affected by emissions from the proposed source or modification.

**VII. Negligibly Reactive Volatile Organic Compounds (NRVOCs)**

VII.A. The negligibly reactive volatile organic compounds referenced in the Common Provisions definition of negligibly reactive volatile organic compounds are considered to be of negligible photochemical reactivity and are neither counted as reactive volatile organic compounds in determining volatile organic compound emission contributions to an increase in ozone nor used as volatile organic compound emission offsets or other volatile organic compound emission trading credits against volatile organic compounds not listed in the common provisions negligibly reactive volatile organic compound definition.

VII.B. Negligibly reactive volatile organic compounds may be substituted for volatile organic compounds and the resulting decrease in volatile organic compound emissions, if otherwise creditable, may be used for offset, banking or other emission trading credit.

**VIII. Area Classifications**

VIII.A. The following areas in Colorado shall be Class I areas and may not be redesignated:

VIII.A.1. National Parks

VIII.A.1.a. Rocky Mountain

VIII.A.1.b. Mesa Verde

VIII.A.2. National Wilderness Areas

VIII.A.2.a. Black Canyon of the Gunnison

VIII.A.2.b. Eagle's Nest

VIII.A.2.c. Flattops

VIII.A.2.d. Great Sand Dunes

VIII.A.2.e. La Garita

VIII.A.2.f. Maroon Bells - Snowmass

VIII.A.2.g. Mount Zirkel

VIII.A.2.h. Rawah

VIII.A.2.i. Weminuche

VIII.A.2.j. West Elk

VIII.B. All other areas of Colorado, unless otherwise specified by Act of Congress or the Colorado legislature, or the Commission pursuant to Section IX. are designated Class II; provided, however that in the following areas as they existed on August 7, 1977 (maps available from the Division), the increase allowed in sulfur dioxide concentrations over the baseline concentration shall be the same as the increase established by Section 163(b) of the Federal Act for Class I areas, except that such allowable increases may not be allowed if a Federal Land Manager should make an adverse impact determination under Section XIII.C. with which the Division concurs and except that such allowable increases, may be exceeded by compliance with the provisions of Sections XIII.D., XIII.E., or XIII.F.:

VIII.B.1. National Monuments

VIII.B.1.a. Florissant Fossil Beds

VIII.B.1.b. Colorado

VIII.B.1.c. Dinosaur

VIII.B.1.d. Great Sand Dunes (those portions not included as National Wilderness Areas in Section VIII.A.2.)

VIII.B.2. Forest Service Primitive Areas

VIII.B.2.a. Uncompahgre Mountain

VIII.B.2.b. Wilson Mountain

VIII.B.3. Lands administered by the Federal Bureau of Land Management in the Gunnison Gorge Recreation Area as of October 27, 1977. All areas designated Class II under this section may be redesignated as provided in Section IX. of this part.

VIII.B.4. National Parks

Black Canyon of the Gunnison (those portions not included as National Wilderness Areas in Section VIII.A.2.)

VIII.C. The following areas may be redesignated only as Class I or II.

VIII.C.1. An area that exceeds ten thousand acres in size and is a national monument, a national primitive area, a national preserve, a national recreational area, a national wild and scenic river, a national wildlife refuge, a national lakeshore; and

VIII.C.2. A national park or national wilderness area established after August 7, 1977, that exceeds ten thousand acres in size.

VIII.D. The Commission recognizes out of state Class I areas that have been listed in the Federal Register (44 Fed. Reg. 69124). Emissions from sources in Colorado shall not violate any standard in these areas.

**IX. Redesignation**

IX.A. Except as otherwise provided in this section or Section VIII. of this part, the Commission may redesignate any area in Colorado as Class I, Class II or Class III as herein provided. The Commission will provide notice to the General Purpose Unit of local government in an area where the maximum allowable increase is being approached.

IX.B. The Commission shall review and consider a request for redesignation by any person.

IX.C. The Commission shall not set a hearing date on a proposed redesignation until the following have been completed:

IX.C.1. A complete description of the area proposed for redesignation;

IX.C.2. A detailed statement of the circumstances that support the proposed redesignation;

IX.C.3. A prediction of the costs and benefits for the affected population from the proposed redesignation;

IX.C.4. A technical analysis of expected impacts on ambient air quality in adjacent or nearby areas;

IX.C.5. Comments, or evidence of an opportunity for submission of comments, by all appropriate regional planning agencies and councils of government organizations, affected municipalities and other affected political subdivisions; and

IX.C.6. An analysis of the relationship of the proposed redesignation with applicable county or regional development plans, including but not limited to, comprehensive area wide plans and 208 water quality plans.

IX.D. The Commission shall provide sixty day notice prior to a public hearing, including notice to other states, Indian governing bodies and Federal Land Managers whose lands may be affected by a proposed redesignation, of any proposed redesignation, and conduct public hearings on such proposed redesignation in or near areas within Colorado that may be affected by such proposed redesignation, including at least one public hearing within or as near as is practicable to the area to be redesignated. At least thirty days prior to any such public hearings, the Commission shall make available for public inspection a discussion of the reasons for the proposed redesignation, including a satisfactory description and analysis of the health, environmental, economic, and societal and energy effects of the proposed redesignation. The notice announcing any public hearings shall contain appropriate notification of the availability of such discussion.

IX.E. Prior to the issuance of notice respecting the proposed redesignation of an area that includes any federal lands, the Commission shall provide written notice to the appropriate Federal Land Manager and afford adequate opportunity (not in excess of sixty days) to confer with the Commission respecting the notice of proposed redesignation and to submit written comments and recommendations with respect to such notice of proposed redesignation. In redesignating any area with respect to which any Federal Land Manager had submitted written comments and recommendations, the Commission shall publish a list of any inconsistency between such redesignation and such comments and recommendations and an explanation of such inconsistency (together with the reasons for making such redesignation against the recommendation of the Federal Land Manager).

IX.F. All redesignations, except any established by an Indian governing body, shall be specifically approved; (1) by the governor, after consultation with the appropriate committees of the legislature, if it is in session, or with the leadership of the legislature, if it is not in session, and (2) by resolutions or ordinances enacted by the general purpose units of local government representing a majority of the residents of the area to be redesignated.

IX.G. No area may be redesignated if such redesignation would cause or contribute to concentrations of any air pollutant in any other area that exceed any maximum allowable increase or maximum allowable concentration permitted under the classification of such area.

IX.H. Lands within the exterior boundaries of reservations of federally recognized Indian tribes may be redesignated only by the appropriate Indian governing body.

IX.I. Any redesignation shall constitute a revision to the Colorado State Implementation Plan and shall be submitted for approval to the Administrator of the U.S. EPA.

IX.J. Any redesignation or denial of a proper request for redesignation made pursuant to this Section IX. shall be subject to judicial review in accord with Colorado Revised Statute Section 25-7-120.

IX.K. Any area other than an area to which Sections VIII.A. or VIII.C. refer to may be redesignated as Class III if any major stationary source or major modification could receive a permit only if the area in question were redesignated as Class III, and any material submitted as part of that application were available, insofar as was practicable, for public inspection prior to any public hearing on redesignation of any area as Class III.

## X. Air Quality Limitations

X.A. Ambient Air Increments

X.A.1. The maximum allowable increases over the baseline concentration for sulfur dioxide, PM10, PM2.5 or nitrogen dioxide except as provided in Section VIII.B. of this part, are:

X.A.1.a. For any Class I area:

| **PM2.5 (µg/m$^3$)** | |
|---|---|
| Annual arithmetic mean | 1 |
| Twenty-four hour maximum | 2 |
| **PM10 (µg/m$^3$)** | |
| Annual arithmetic mean | 4 |
| Twenty-four hour maximum | 8 |
| **Sulfur dioxide (µg/m$^3$)** | |
| Annual arithmetic mean | 2 |
| Twenty-four hour maximum | 5 |
| Three hour maximum | 25 |
| **Nitrogen dioxide (µg/m$^3$)** | |
| Annual arithmetic mean | 2.5 |

X.A.1.b. For any Class II area:

| **PM2.5 (µg/m$^3$)** | |
|---|---|
| Annual arithmetic mean | 4 |
| Twenty-four hour maximum | 9 |
| **PM10 (µg/m$^3$)** | |
| Annual arithmetic mean | 17 |
| Twenty-four hour maximum | 30 |
| **Sulfur dioxide (µg/m$^3$)** | |
| Annual arithmetic mean | 20 |
| Twenty-four hour maximum | 91 |
| Three hour maximum | 512 |
| **Nitrogen dioxide (µg/m$^3$)** | |
| Annual arithmetic mean | 25 |

X.A.1.c. For any Class III area:

| | |
|---|---|
| **PM2.5 (µg/m$^3$)** | |
| Annual arithmetic mean | 8 |
| Twenty-four hour maximum | 18 |
| **PM10 (µg/m$^3$)** | |
| Annual arithmetic mean | 34 |
| Twenty-four hour maximum | 60 |
| **Sulfur dioxide (µg/m$^3$)** | |
| Annual arithmetic mean | 40 |
| Twenty-four hour maximum | 182 |
| Three hour maximum | 700 |
| **Nitrogen dioxide (µg/m$^3$)** | |
| Annual arithmetic mean | 50 |

X.A.2. The maximum allowable increases over the baseline concentration for any other air pollutant shall be the same as those increases established pursuant to Section 165(a) of the Federal Act.

X.A.3. For any period other than an annual period, the applicable maximum allowable increase may be exceeded during one such period per year at any one location.

X.A.4. Periodic Review

X.A.4.a. The Division shall, on a periodic basis, review the adequacy of this Regulation Number 3 for preventing significant deterioration of air quality. Within thirty days after any information becomes available and there is cause to believe that an applicable increment is being violated, the Division shall present the cause for such belief to the Commission.

X.A.4.b. If the Commission concurs that there is cause to believe that an increment is being violated, it shall hold a hearing to determine whether an increment violation exists. The hearing shall be held pursuant to the procedures of Colorado Revised Statute Section 25-7-119. Notice should be given by first class mail to permitted sources that can be reasonably identified as emitting the pollutant in violation and affecting the area of violation.

X.A.4.c. Should the Commission determine that an increment violation exists, the Division shall review all sources affecting the area of increment violation and ensure that all such sources comply with all applicable permit conditions, and state and local regulations. Within thirty days after completing such a review, the Division shall recommend revisions, if necessary, to the Commission to correct the violation. Upon receipt of recommended revisions from the Division, the Commission shall as soon as practicable act to revise this regulation as it deems necessary.

X.A.5. Increment Consumption Restriction

X.A.5.a. No new major stationary source or major modification shall individually consume more than seventy-five percent of an applicable increment.

X.A.5.a.(i) Applicants may request a hearing before the Commission to request a waiver of this restriction. The hearing shall be heard in accordance with the provisions of Colorado Revised Statute Sections 25-7-114 (4)(h), 25-7-119 (Colorado Air Pollution Prevention and Control Act), and Colorado Revised Statute 24-4-105 (State Administrative Procedure Act).

X.A.5.a.(i)(A) The Commission shall not set a hearing date for a waiver request until submittal of comments, or evidence of an opportunity for submittal of comments by all appropriate regional planning agencies and councils of government organizations, affected municipalities and other affected political subdivisions has occurred.

X.A.5.a.(i)(B) Ambient Air Limits. No concentrations of a pollutant shall exceed a national ambient air quality standard or a state ambient air standard where no national ambient air quality standard has been established.

## XI. Exclusions From Increment Consumption

XI.A. The following concentrations are excluded in determining compliance with a maximum allowable increase:

XI.A.1. Concentrations attributable to the increase in emissions from stationary sources that have converted from the use of petroleum products, natural gas, or both by an order in effect under Sections 2(a) and (b) of the federal "Energy Supply and Environmental Coordination Act of 1974" (or any superseding legislation) over the emissions from such sources before the effective date of such an order, but not more than five years after the effective date of such an order.

XI.A.2. Concentrations attributable to the increase in emissions from sources that have converted from using natural gas by reason of a natural gas curtailment plan in effect pursuant to the Federal "Power Act" over the emissions from such sources before the effective date of such plan, but not more than five years after the effective date of the plan.

XI.A.3. Concentrations of particulate matter attributable to an increase in emissions from construction or other temporary emission-related activities of new or modified sources.

XI.A.4. Concentrations attributable to the temporary increase in emissions of sulfur dioxide, or particulate matter, or nitrogen oxides from stationary sources that are affected by revisions of the Colorado State Implementation Plan that are approved by the Administrator of the U.S. EPA and that provide:

XI.A.4.a. The time period of such temporary increase in emissions is not renewable and may not exceed two years in duration, unless a longer time is approved by the Division and the U.S. EPA;

XI.A.4.b. Such temporary increase in emissions shall not impact a Class I area or an area where an applicable increment is known to be violated or cause or contribute to the violation of a national ambient air quality standard; and

XI.A.4.c. Emission limitations shall be in effect at the end of the time period specified in the plan revision that will ensure that the emissions levels from stationary sources affected by the plan revision will not exceed those levels occurring from such sources before the plan revision was approved by the U.S. EPA.

## XII. Innovative Control Technology

XII.A. An owner or operator of a proposed major stationary source or major modification otherwise subject to the requirements of Section VI. of this Part D may request the Division to grant a waiver from the Best Available Control Technology requirements and to approve a system of innovative control technology, in order to encourage the use of such technology.

XII.B. The Division or the Commission may, with the consent of the governor(s) of other affected states, grant a waiver from the Best Available Control Technology requirements of Section VI.A.1. of this part necessary for the employment of innovative control technology and determine that the source or modification may employ such system if:

XII.B.1. The proposed control system would not cause or contribute to an unreasonable risk to public health, welfare, or safety in its operation or function;

XII.B.2. The owner or operator agrees to achieve a level of continuous emissions reduction greater than or equivalent to that, which would have been required under Section VI.A.1. by a date specified by the Division. Such date shall not be later than four years from the time of startup or seven years from permit issuance;

XII.B.3. The source or modification would meet the requirements of Sections VI.A.1. and VI.A.2. based on the emissions rate that the stationary source employing the system of innovative control technology would be required to meet on the date specified by the Division;

XII.B.4. The source or modification would not, before the date specified by the Division under Section XII.B.2., above;

XII.B.4.a. Cause or contribute to any violation of an applicable national ambient air quality standard; or

XII.B.4.a.(i) Impact any area where an applicable increment is known to be violated; or

XII.B.5. All other applicable requirements including those for public participation have been met.

XII.B.6. The provisions of Section VIII. of this part (relating to Class I areas) have been satisfied with respect to all periods during the life of the source or modification.

XII.C. The Division shall withdraw any approval to employ a system of innovative control technology made under this section, if:

XII.C.1. The proposed system fails by the specified date to achieve the required continuous emissions reduction rate; or

XII.C.2. The proposed system fails before the specified date so as to contribute to an unreasonable risk to public health, welfare, or safety; or

XII.C.3. The Division decides at any time that the proposed system is unlikely to achieve the required level of control or to protect the public health, welfare, or safety.

XII.D. If a source or modification fails to meet the required level of continuous emissions reduction within the specified time period, or if the approval is withdrawn in accordance with Section XII.C., above, the Division may allow the source or modification up to an additional three years to meet the requirement for the application of best available control technology through use of a demonstrated system of control.

**XIII. Federal Class I Areas**

XIII.A. Within twenty days of receipt of a permit application for a new major stationary source or major modification that may affect visibility or air quality related values in any Federal Class I area, the Division shall transmit a copy of the application to all affected Federal Land Managers and consult with them as to its completeness in its analysis and monitoring (if required) of air quality related values. If the Division receives advance notification of a permit application of a source that may affect visibility or air quality related values, it will notify all affected Federal Land Managers within thirty days of such notification. The Division will consider any analysis performed by a Federal Land Manager that indicates there will be an adverse impact on visibility or air quality related values if such analysis is received within thirty days after the Federal Land Manager receives a copy of the complete application. If the Division disagrees with the Federal Land Manager, any notices for public comment or of a public hearing on the application will explain the disagreement or state where the explanation can be obtained.

XIII.B. In addition to the general impact analysis required by Section VI.A.6. of this part, any source that will have or is likely to have an impact on any designated Class I area may be required to conduct monitoring to establish the condition of and the impact on air quality related values in such Class I area(s) both prior to completing an application for a permit to construct and during the construction and operation of such source.

XIII.B.1. If monitoring is required, the source shall conduct a private monitoring program. However, if monitoring is being conducted by any other existing source or government agency, the new source may enter into a joint monitoring program with that source or agency. All monitoring programs must be approved in advance by the Division.

XIII.B.2. Pre-application monitoring may include the monitoring of not more than three air quality related values or sensitive receptors of air quality related values specified by the Division after consultation with the Federal Land Manager. The air quality related values or sensitive receptor(s) selected must be important to the affected Class I area, and there must be cause to believe that monitoring of the air quality related values or sensitive receptors will provide a basis for evaluating effects to the relevant air quality related values.

XIII.B.3. Monitoring during construction and operation may only be required for the sensitive receptors specified for pre-application monitoring, unless new information becomes available that demonstrates a significant economic or technological advantage of monitoring a different sensitive receptor, and it is acceptable to the source owner or operator.

XIII.B.4. Monitoring of air quality related values or sensitive receptors of air quality related values may only be required if:

XIII.B.4.a. Monitoring methods are reasonably available and research and development of monitoring methods are unnecessary;

XIII.B.4.b. The major effect on the air quality related values or sensitive receptor would reasonably be predicted to be a result of the applicant's individual emissions or of the applicant's emissions in combination with any person's emissions with whom the applicant may be required to conduct joint monitoring; and

XIII.B.4.c. It is economically reasonable for the source to conduct such monitoring.

XIII.C. Sources Impacting Federal Class I Area - Additional Requirements. Federal Land Managers may present to the Division, after its preliminary analysis required under Section III.B. of Part B of this regulation, a demonstration that the emissions from the proposed source or modification would have an adverse impact on the air quality related values (including visibility) of any federal mandatory Class I lands, notwithstanding that the change in air quality resulting from emissions from such source or modification would not cause or contribute to concentrations that would exceed the maximum allowable increases for a Class I area. If the Division concurs with such demonstration, or in the event the Federal Land Manager fails to perform an adverse impact analysis and the Division determines that there is an adverse impact on visibility, or the Division determines that a demonstration of no adverse impact is in error, the Division shall not issue the permit.

XIII.D. Class I Variances. The owner or operator of a proposed major stationary source or major modification may demonstrate to the satisfaction of the Federal Land Manager that the emissions from such source or modification would not have an adverse impact on the air quality related values (including visibility) of Class I lands under the Federal Land Manager's jurisdiction, notwithstanding that the change in air quality resulting from emissions from such source or modification would cause or contribute to concentrations that would exceed the maximum allowable increases for a Class I area. If the Federal Land Manager concurs with such demonstration and so certifies to the Division, the Division or the Commission may, provided that applicable requirements are otherwise met, issue the permit with such emission limitations as may be necessary to assure that emissions of sulfur dioxide, and PM10, PM2.5 and nitrogen oxides would not exceed the following maximum allowable increases over the minor source baseline concentration for such pollutants.

| **Maximum allowable increase** | |
|---|---|
| Particulate matter | |
| PM2.5, Annual arithmetic mean | 4 µg/m$^3$ |
| PM2.5, Twenty-four hour maximum | 9 µg/m$^3$ |
| PM10, Annual arithmetic mean | 17 µg/m$^3$ |
| PM10, Twenty-four hour maximum | 30 µg/m$^3$ |
| Sulfur dioxide | |
| Annual arithmetic mean | 20 µg/m$^3$ |
| Twenty-four hour maximum | 91 µg/m$^3$ |
| Three hour maximum | 325 µg/m$^3$ |
| Nitrogen dioxide | |
| Annual arithmetic mean | 25 µg/m$^3$ |

XIII.E. Sulfur Dioxide Variance by Governor

XIII.E.1. The owner or operator of a proposed major stationary source or major modification that cannot be approved under Section XIII.D., above, may demonstrate to the governor that the source or modification cannot be constructed by reason of any maximum allowable increase for sulfur dioxide for periods of twenty-four hours or less, applicable to any Class I area and, in the case of the federal mandatory Class I areas, that a variance under this section would not have an adverse affect on the air quality related values of the area (including visibility).

XIII.E.2. The governor, after consideration of the Federal Land Manager's recommendation (if any) and subject to his concurrence, may grant, after notice and an opportunity for a public hearing, a variance from such maximum allowable increase.

XIII.E.3. If such variance is granted, the Division may issue a permit to such source or modification in accordance with Section XIII.G., below, if the applicable requirements of Regulation Number 3 are otherwise met.

XIII.F. Variance by the Governor with the President's Concurrence

XIII.F.1. The recommendations of the governor and the Federal Land Manager shall be transferred to the president in any case where the governor recommends a variance with which the Federal Land Manager does not concur.

XIII.F.2. If the president approves the variance, the Division may issue a permit in accordance with Section XIII.G., below, if the applicable requirements of Regulation Number 3 are otherwise met.

XIII.G. Emission Limitations for Presidential and Gubernatorial Variance. In the case of a permit to be issued under Sections XIII.E. and XIII.F., the source or modification shall comply with emission limitations as may be necessary to assure that emissions of sulfur dioxide from the source or modification would not (during any day on that the otherwise applicable maximum allowable increases are exceeded) cause or contribute to concentrations that would exceed the following maximum allowable increases over the baseline concentration assure that such emissions would not cause or contribute to concentrations that exceed the otherwise applicable maximum allowable increases for periods of exposure of twenty-four hours or less for more than eighteen days, not necessarily consecutive, during any annual period:

Maximum Allowable Increase (µg/m3)

| **Period of Exposure** | **Terrain Areas** | |
|---|---|---|
| | **Low** | **High** |
| 24-hour maximum | 36 | 62 |
| 3-hour maximum | 130 | 221 |

**XIV. Visibility**

XIV.A. Purpose

This section assures reasonable progress towards the national goal of preventing future, and remedying existing, visibility impairment in Class I areas, where such impairment results from man-made air pollution.

XIV.B. Applicability

This section applies to all Class I areas and to sources in Colorado the emissions from which may reasonably be anticipated to cause or contribute to any impairment of visibility in any such area (even if the area is in another state).

XIV.C. Definitions

For purposes of this Section XIV.

XIV.C.1. Adverse impact on visibility means for the purpose of Section XIV.E. visibility impairment that interferes with the management, protection, preservation, or enjoyment of the visitor's visual experience of the Class I area. Any determination shall be made on a case-by-case basis taking into account the geographic extent, intensity, duration, frequency and time of visibility impairments, and how these factors correlate with times of visitor use of the Class I area, and the frequency and timing of natural conditions that reduce visibility.

XIV.C.2. Best Available Retrofit Technology means an emission limitation achievable through the application of the best system of continuous emission reduction for each pollutant that is emitted by an existing stationary facility. The emission limitation shall be established on a case-by-case basis taking into consideration the technology available, the costs of compliance, the energy and non-air quality environmental impacts of compliance, any pollution control equipment in use or in existence at the source, the remaining useful life of the source, and the degree of improvement in visibility that may reasonably be anticipated to result from the use of such technology.

XIV.C.3. Existing stationary facility means any of the stationary sources of air pollutants defined in Sections I.B.19., I.B.24. through I.B.27., I.B.36., and I.B.43. of Part A, Section I.A.1.(c) of Part C, and Section II.A.24. of Part D of this regulation, including any reconstructed source that was not in operation prior to August 7, 1962, and had commenced construction on or before August 7, 1977, and has the potential to emit two hundred and fifty tons per year or more of any air pollutant. In determining potential to emit, fugitive emissions, to the extent quantifiable shall be counted.

XIV.C.4. Long-term strategy means a ten to fifteen year plan for making reasonable progress toward the national goal specified in Section XIV.A. of this part.

XIV.C.5. Natural conditions include naturally occurring phenomena that reduce visibility as measured in terms of visual range, contrast, or coloration.

XIV.C.6. Reasonably attributable means attributable by visual observation or any other technique the state deems appropriate.

XIV.C.7. Significant impairment means, for purposes of Section XIV.D.2.c., visibility impairment, that interferes with the management, protection, preservation or enjoyment of the visitor's visual experience of the Class I area.

XIV.C.8. Visibility impairment means any humanly perceptible change in visibility (visual range, contrast, coloration) that would have existed under natural conditions.

XIV.C.9. Class I area means an area listed in Section VIII.A. of this part and any area that may be redesignated to Class I in the future.

XIV.D. Existing Impairment

XIV.D.1. The Federal Land Manager or the Division may, at any time, certify to the Division director that visibility impairment exists in any Class I area. The Division may also certify that visibility impairment exists in any Class I area without the concurrence of the Federal Land Manager.

XIV.D.2. Each existing stationary facility located in Colorado to which the cause of or contribution to visibility impairment in any Class I area is reasonably attributable, shall

apply for and obtain from the Division a permit that requires the installation and operation of Best Available Retrofit Technology. The facility shall install and operate Best Available Retrofit Technology as expeditiously as practicable but in no case later than five years after permit issuance.

XIV.D.2.a. For fossil-fuel fired generating plants having a total generating capacity in excess of 750 megawatts, Best Available Retrofit Technology shall be determined pursuant to "Guidelines for Determining Best Available Retrofit Technology for Coal-fired Power Plants and Other Existing Stationary Facilities" (U.S. EPA Publication Number 450/3-80-009b, 1980), and state of the art information available at the time of Best Available Retrofit Technology analysis. Pursuant to Colorado Revised Statute Section 24-4-103 (12.5), the document referenced in this section is available for public inspection during normal working hours, or copies are available for cost, from the technical secretary of the Commission, 4300 Cherry Creek Drive South, Denver, Colorado 80246-1530. This Regulation Number 3 does not include later amendments to or editions of the referenced documents.

XIV.D.2.b. Should technological or economic limitations make the application of Best Available Retrofit Technology as previously defined infeasible; the state may instead prescribe a design, equipment, work practice, or other operational standard, or combination thereof, as representing Best Available Retrofit Technology. Where a facility is subject to Section XIV.D.2.a., due to technological limitations, the facility shall install and operate Best Available Retrofit Technology as previously defined when new technology for control of the pollutant becomes reasonably available provided: 1) the pollutant is emitted by the existing facility; 2) controls representing Best Available Retrofit Technology for the pollutant have not previously been required under this section; and 3) the impairment of visibility in any Class I area is reasonably attributable to the emissions of that pollutant.

XIV.D.2.c. Any existing stationary facility required to install and operate Best Available Retrofit Technology under this section may apply to the Division and the U.S. EPA Administrator for an exemption.

XIV.D.2.c.(i) An application under this section must include all available documentation relevant to the impact of the source's emissions on visibility in any Class I area and a demonstration by the existing stationary facility that it does not or will not by itself or in combination with other sources, emit any air pollutant that may be reasonably anticipated to cause or contribute to a significant impairment of visibility in any Class I area.

XIV.D.2.c.(ii) Any fossil fuel fired power plant with a total generating capacity of 750 megawatts or more may receive an exemption from Best Available Retrofit Technology only if the owner or operator of such power plant demonstrates to the satisfaction of the Division that such power plant is located at such a distance from all Class I areas that such power plant does not or will not by itself or in combination with other sources emit any air pollutant that may reasonably be anticipated to cause or contribute to significant impairment of visibility in any such Class I area.

XIV.D.2.c.(iii) The existing stationary facility must give prior written notice to all affected Federal Land Managers of any application for exemption.

XIV.D.2.c.(iv) The Federal Land Manager may provide an initial recommendation or comment on the disposition of such application. Such recommendation, where provided, must be part of the exemption application. This recommendation is not to be construed as the concurrence required under Section XIV.D.2.c.(iv).

XIV.D.2.c.(v) After notice and opportunity for public hearing, before the Commission, the Division may grant or deny the exemption.

XIV.D.2.c.(vi) An exemption granted by the Division under this section will be effective only upon concurrence by all affected Federal Land Managers.

XIV.D.2.c.(vii) Any determination shall be made on a case-by-case basis taking into account the geographic extent, intensity, duration, frequency and time of the visibility impairment, and how these factors correlate with time of visitor use of the Class I area, and the frequency and timing of natural conditions that reduce visibility.

XIV.D.2.d. The Division shall process any application for a permit required by Section XIV.D.2., above, or any application for exemption under Section XIV.D.2.b., according to the time constraints stated in Part B, Section III.B. of this regulation. All applications for permits or exemptions will be subject to public notice and public hearing requirements applicable to sources subject to the provisions of Section VI. of this part. Processing fees will be charged to the applicant to recover actual costs incurred by the Division as stated in Section VI. of Part A of this Regulation Number 3.

XIV.E. New Source Review

Applicants for new major stationary sources and major modifications shall demonstrate that the proposed source will not have an adverse impact on visibility in a Class I area as required by Sections V.A.6., VI.A.6., and XIII. of this part.

XIV.F. Long-term Strategy

XIV.F.1. The Commission shall review and revise, if appropriate, the long-term strategy every five years.

XIV.F.1.a. During the long-term strategy development and review process, the Commission shall consult with the Federal Land Managers.

XIV.F.1.b. A public hearing shall be held upon request of any interested person. The state shall provide written notification to each affected Federal Land Manager and other affected states at least sixty days prior to holding any public hearing.

XIV.F.1.c. The Division shall prepare a report for the Commission on any progress made toward the national visibility goal since the last long-term strategy revisions. The report will be made available on September 1, at least every fifth year following the submittal of the previous report and consistent with the federal five-year Regional Haze reporting schedule. The report shall include an assessment of:

XIV.F.1.c.(i) The progress achieved in remedying existing impairment of visibility in any Class I area;

XIV.F.1.c.(ii) The ability of the long-term strategy to prevent future impairment of visibility in any Class I area;

XIV.F.1.c.(iii) Any change in visibility since the last such report, or in the case of the first report, since plan approval, including an assessment of existing conditions;

XIV.F.1.c.(iv) Additional measures, including the need for state implementation plan revisions, that may be necessary to assure reasonable progress toward the national visibility goal;

XIV.F.1.c.(v) The progress achieved in implementing Best Available Retrofit Technology and meeting other schedules set forth in the long-term strategy;

XIV.F.1.c.(vi) The impact of any exemption granted under Section XIV.D.2.c.; and,

XIV.F.1.c.(vii) The need for Best Available Retrofit Technology to remedy existing impairment in an integral vista declared since plan approval.

XIV.G. Public Land Emission Inventories

XIV.G.1. Federal Public Lands

XIV.G.1.a. For the purposes of this Section XIV.G., federal land management agency means a federal agency that owns and manages at least 50,000 acres of federal land in Colorado.

XIV.G.1.b. Federal land management agencies shall submit to the Commission emission inventories by December 31, 2001 and no less frequently than every five years thereafter.

XIV.G.1.c. The inventory shall include the sources listed in Section XIV.G.3.b. of this regulation and emissions of criteria pollutants, including surrogates or precursors for such pollutants, from activities in Colorado or other states that may affect any mandatory class I federal area in Colorado by reducing visibility in such area.

XIV.G.2. Colorado State Public lands

XIV.G.2.a. The Division shall submit to the Commission emission inventories for all state land management agencies including the State Land Board, the Department of Agriculture, and the Department of Natural Resources by July 1, 2002 and no less frequently than every five years thereafter.

XIV.G.2.b. The inventory shall include the sources listed in Section XIV.G.3.b. of this regulation and emissions of criteria pollutants, including surrogates or precursors for such pollutants, from activities in Colorado that may affect any mandatory Class I federal area in Colorado by reducing visibility in such area.

XIV.G.3. Public Land Emission Inventory Requirements

XIV.G.3.a. The inventory shall include both current emissions and projected future emissions, over at least a five-year period.

XIV.G.3.b. The following sources on public lands shall be included in the inventory:

XIV.G.3.b.(i) Stationary source emissions, based on existing air pollution emission notices filed with the Division;

XIV.G.3.b.(ii) Mobile sources utilizing state lands, excluding state and federal highways;

XIV.G.3.b.(iii) Paved and unpaved roads;

XIV.G.3.b.(iv) Fires on public lands from all sources; and

XIV.G.3.b.(v) Biogenic sources, including emissions from flora and fauna.

XIV.G.4. Public Hearings

Not later than December 31, 2002, and no less frequently than every five years thereafter, a public hearing before the Commission shall be conducted to approve the public land emission inventories.

## XV. Actuals PALs

XV.A. Applicability.

XV.A.1. At the request of an owner or operator, the Division may approve the use of an actuals PAL, including for GHGs on either a mass basis or a CO2e basis, in a Title V permit for any existing major stationary source or any existing GHG-only source that has operated for at least two years if the PAL meets the requirements in Sections XV.A. through XV.L. The term “PAL” shall mean “actuals PAL” throughout Section XV. of this part.

XV.A.2. Any physical change in or change in the method of operation of a major stationary source or a GHG-only source that maintains its total source-wide emissions below the PAL level, meets the requirements in Sections XV.A. through XV.L., and complies with the PAL permit:

XV.A.2.a. Is not a major modification for the PAL pollutant;

XV.A.2.b. Is not subject to the major NSR review procedures in Sections I.B., V., and VI. of this part;

XV.A.2.c. Is not subject to the provisions in Section V.A.5.b. of this part (restrictions on relaxing enforceable emission limitations that the major stationary source used to avoid applicability of the major NSR program); and

XV.A.2.d. Does not make GHGs subject to regulation as defined in Part A, Section I.B.44.

XV.A.3. Except as provided under Section XV.A.2.c. above, a major stationary source or a GHG-only source shall continue to comply with all applicable Federal or State requirements, emission limitations, and work practice requirements that were established prior to the effective date of the PAL.

XV.B. Permit application requirements.

As part of a permit application requesting a PAL, the owner or operator of a major stationary or a GHG-only source source shall submit the following information to the Division for approval (in addition to the information required by Part C of this Regulation):

XV.B.1. A list of all emissions units at the source designated as small (as defined in Section II.A.47. of this part), significant (as defined in Section II.A.46. of this part), and major (as defined in Section II.A.22. of this part) based on their potential to emit, and identifying each as such. In addition, the owner or operator of the source shall indicate which, if any, Federal or State applicable requirements, emission limitations or work practices apply to each unit.

XV.B.2. Calculations of the baseline actual emissions for each emissions unit listed in Section XV.B.1. above (with supporting documentation). Baseline actual emissions are to include emissions associated not only with operation of the unit, but also emissions associated with startup, shutdown and malfunction.

XV.B.3. The calculation procedures that the major stationary source owner or operator proposes to use to convert the monitoring data to monthly emissions and annual emissions based on a twelve-month rolling total for each month as required by Section XV.M.1.

XV.B.4. As part of a permit application requesting a GHG PAL, the owner or operator of a major stationary source or a GHG-only source shall submit a statement by the source owner or operator that clarifies whether the source is an existing major source as defined in Sections II.A.24.a. and II.A.24.b. or a GHG-only source as defined in Section XV.P.1.

XV.C. General requirements for establishing PALs.

XV.C.1. A PAL may be established at a major stationary source or a GHG-only source, provided that, at a minimum, the requirements in Sections XV.C.1.a. through XV.C.1.g. below are met.

XV.C.1.a. The PAL shall impose an annual emission limitation expressed on a mass basis in tons per year, or expressed in tons per year CO2e, that is enforceable as a practical matter, for the entire major stationary source or GHG-only source. For each month during the PAL effective period after the first twelve months of establishing a PAL, the major stationary source or GHG-only source owner or operator shall demonstrate that the sum of the monthly emissions of the PAL pollutant from each emissions unit under the PAL for the previous twelve consecutive months is less than the PAL (a rolling twelve-month total). For each month during the first eleven months from the PAL effective date, the major stationary source or GHG-only source owner or operator shall demonstrate that the sum of the preceding monthly emissions of the PAL pollutant for each emissions unit under the PAL is less than the PAL.

XV.C.1.b. The PAL shall be established in a PAL permit section of an operating permit issued pursuant to Part C of this regulation that meets the public participation requirements in Section XV.D.

XV.C.1.c. The PAL permit shall contain all the requirements of Section XV.F.

XV.C.1.d. The PAL shall include fugitive emissions, to the extent quantifiable, from all emissions units that emit or have the potential to emit the PAL pollutant at the major stationary source or GHG-only source.

XV.C.1.e. Each PAL shall regulate emissions of only one pollutant.

XV.C.1.f. Each PAL shall have a PAL effective period of ten years.

XV.C.1.g. The owner or operator of the major stationary source or GHG-only source with a PAL shall comply with the monitoring, recordkeeping, and reporting requirements provided in Sections XV.K. through XV.N. for each emissions unit under the PAL throughout the PAL effective period.

XV.C.2. At no time (during or after the PAL effective period) are emissions reductions of a PAL pollutant, which occur during the PAL effective period, creditable as decreases for purposes of offsets under Section V. unless the level of the PAL is reduced by the amount of such emissions reductions and such reductions would be creditable in the absence of the PAL.

XV.D. Public participation requirement for PALs.

PALs for existing major stationary sources or GHG-only sources shall be established, renewed, or increased in accordance with the significant modification provisions set forth in Section I.A.7.of Part C of this regulation. The Division shall provide the public with notice of the proposed approval of a PAL permit and a thirty-day period for submittal of public comment.

XV.E. Setting the ten-year actuals PAL level.

XV.E.1. Except as provided in Sections XV.E.4. and XV.E.6., the actuals PAL level for a major stationary source or GHG-only source shall be established as the sum of the baseline actual emissions (as defined in Section II.A.4. of this Part D or, for GHGs in Section XV.P.2.) of the PAL pollutant for each emissions unit at the source, plus an amount equal to the applicable significant level for the PAL pollutant under Section II.A.44. of this part, or under the Federal Act, whichever is lower.

XV.E.2. When establishing the actuals PAL level for a PAL pollutant, only one consecutive twenty-four month period may be used to determine the baseline actual emissions for all existing emissions units. However, a different consecutive twenty-four month period may be used for each different PAL pollutant.

XV.E.3. Emissions associated with units that were permanently shut down after this twenty-four month period must be subtracted from the PAL level.

XV.E.4. For newly constructed units (which do not include modifications to existing units) on which actual construction began after the twenty-four month period, in lieu of adding the baseline actual emissions as specified in Section XV.E.1., above, the emissions must be added to the PAL level in an amount equal to the potential to emit of the units.

XV.E.5. The Division shall specify a reduced PAL level(s) (in tons/yr) in the PAL permit to become effective on the future compliance date(s) of any applicable Federal or State regulatory requirement(s) that the Division is aware of prior to issuance of the PAL permit. For instance, if the source owner or operator will be required to reduce emissions from industrial boilers in half from baseline emissions of 60 ppm NOx to a new rule limit of 30 ppm, then the permit shall contain a future effective PAL level that is equal to the current PAL level reduced by half of the original baseline emissions of such unit(s).

XV.E.6. For CO2e based GHG PAL, the actuals PAL level shall be established as the sum of the GHGs baseline actual emissions (as defined in Section XV.P.2.) of GHGs for each emissions unit at the source, plus an amount equal to the amount defined as "significant" on a CO2e basis for the purposes of Part A, Section I.B.44.c. at the time the PAL permit is being issued.

XV.E.6.a. When establishing the actuals PAL level for a CO2e-based PAL, only one consecutive 24-month period must be used to determine the baseline actual emissions units.

XV.E.6.b. Emissions associated with units that were permanently shut down after this 24-month period must be subtracted from the PAL level.

XV.E.6.c. The Division shall specify a reduced PAL level in tons per year CO2e in the PAL permit to become effective on the future compliance date(s) of any applicable Federal or state regulatory requirement(s) that the Division is aware of prior to issuance of the PAL permit.

XV.F. Contents of the PAL permit.

The PAL permit shall contain, at a minimum, the information in Sections XV.F.1. through XV.F.11.

XV.F.1. The PAL pollutant and the applicable source-wide emission limitation in tons per year CO2e.

XV.F.2. The PAL permit effective date and the expiration date of the PAL (PAL effective period).

XV.F.3. Specification in the PAL permit that if a major stationary source or a GHG-only source owner or operator applies to renew a PAL in accordance with Section XV.I. before the end of the PAL effective period, then the PAL shall not expire at the end of the PAL effective period. It shall remain in effect until a revised PAL permit is issued by the Division.

XV.F.4. A requirement that emission calculations for compliance determination purposes include emissions from startups, shutdowns and malfunctions.

XV.F.5. A requirement that, once the PAL expires, the major stationary source or GHG-only source is subject to the requirements of Section XV.H.

XV.F.6. The calculation procedures that the major stationary source or GHG-only source owner or operator shall use to convert the monitoring data to monthly emissions and annual emissions based on a twelve-month rolling total for each month as required by Section XV.M.1.

XV.F.7. A requirement that the major stationary source or GHG-only source owner or operator monitors all emissions units in accordance with the provisions under Section XV.K.

XV.F.8. A requirement to retain the records required under Section XV.M. on site. Such records may be retained in an electronic format.

XV.F.9. A requirement to submit the reports required under Section XV.N. by the required deadlines.

XV.F.10. Any other requirements that the Division deems necessary to implement and enforce the PAL.

XV.F.11. A permit for a GHG PAL issued to a GHG-only source shall also include a statement denoting that GHG emissions at the source will not be subject to regulation under Part A, Section I.B.44. as long as the source complies with the PAL.

XV.G. Reopening of the PAL permit.

XV.G.1. During the PAL effective period, the Division shall reopen the PAL permit to:

XV.G.1.a. Correct typographical/calculation errors made in setting the PAL or reflect a more accurate determination of emissions used to establish the PAL.

XV.G.1.b. Reduce the PAL if the owner or operator of the major stationary source creates creditable emissions reductions for use as offsets under Section V.A.3. of this Part D.

XV.G.1.c. Revise the PAL to reflect an increase in the PAL as provided under Section XV.J.

XV.G.2. The Division has discretion to reopen the PAL permit to:

XV.G.2.a. Reduce the PAL to reflect newly applicable Federal requirements (for example, NSPS) with compliance dates after the PAL effective date.

XV.G.2.b. Reduce the PAL consistent with any other requirement, that is enforceable as a practical matter, and that the Division may impose on the major stationary source or GHG-only source.

XV.G.2.c. Reduce the PAL if the Division determines that a reduction is necessary to avoid causing or contributing to a NAAQS or PSD increment violation, or to an adverse impact on an air quality related value that has been identified for a Federal Class I area by a Federal Land Manager and for which information is available to the general public.

XV.G.3. Except for the permit reopening in Section XV.G.1.a. for the correction of typographical/calculation errors that do not increase the PAL level, all other reopenings shall be carried out in accordance with the public participation requirements of Section XV.D.

XV.H. Expiration of a PAL.

Any PAL that is not renewed in accordance with the procedures in Section XV.I. shall expire at the end of the PAL effective period, and the requirements in Sections XV.H.1. through XV.H.5. shall apply.

XV.H.1. Each emissions unit (or each group of emissions units) that existed under the PAL shall comply with an allowable emission limitation under a revised permit established according to the procedures in Sections XV.H.1. through XV.H.5. of this part.

XV.H.1.a. Within the time frame specified for PAL renewals in Section XV.I.2., the major stationary source or GHG-only source shall submit a proposed allowable emission limitation for each emissions unit (or each group of emissions units, if such a distribution is more appropriate as determined by the Division) by distributing the PAL allowable emissions for the major stationary source or GHG-only source among each of the emissions units that existed under the PAL. If the PAL had not yet been adjusted for an applicable requirement that became effective during the PAL effective period, as required under Section XV.I.5., such distribution shall be made as if the PAL had been adjusted.

XV.H.1.b. The Division shall determine whether and how the PAL allowable emissions will be distributed and issue a revised permit incorporating allowable limits for each emissions unit, or each group of emissions units, as the Division determines is appropriate.

XV.H.2. Each emissions unit(s) shall comply with the allowable emission limitation on a twelve-month rolling total basis. The Division may approve the use of monitoring systems (source testing, emission factors, etc.) other than CEMS, CERMS, PEMS or CPMS to demonstrate compliance with the allowable emission limitation.

XV.H.3. Until the Division issues the revised permit incorporating allowable limits for each emissions unit, or each group of emissions units, as required under Section XV.H.1.a., the source shall continue to comply with a source-wide, multi-unit emissions cap equivalent to the level of the PAL emission limitation.

XV.H.4. Any physical change or change in the method of operation at the major stationary source or GHG-only source will be subject to the major NSR requirements if such change meets the definition of major modification in Section II.A.23. of this Part D.

XV.H.5. The major stationary source or GHG-only source owner or operator shall continue to comply with any State or Federal applicable requirements that may have applied either during the PAL effective period or prior to the PAL effective period except for those emission limitations that had been established pursuant to Sections V.A.7.b. and VI.B.4. of this part, but were eliminated by the PAL in accordance with the provisions in Section XV.A.2.c.

XV.I. Renewal of a PAL.

XV.I.1. The Division shall follow the procedures specified in Section XV.D. in approving any request to renew a PAL for a major stationary source or GHG-only source, and shall provide both the proposed PAL level and a written rationale for the proposed PAL level to the public for review and comment. During such public review, any person may propose a PAL level for the source for consideration by the Division.

XV.I.2. Application deadline.

A major stationary source or GHG-only source owner or operator shall submit a timely application to the Division to request renewal of a PAL. A timely application is one that is submitted at least twelve months prior to, but not earlier than eighteen months from, the date of PAL permit expiration. This deadline for application submittal is to ensure that the permit will not expire before the permit is renewed. If the owner or operator of a major stationary source or GHG-only source submits a complete application , including any additional information requested by the Division, to renew the PAL within this time period, then the PAL shall continue to be effective until the revised permit with the renewed PAL is issued.

XV.I.3. Application requirements.

The application to renew a PAL permit shall contain the information required in Sections XV.I.3.a. through XV.I.3.d., below.

XV.I.3.a. The information required in Sections XV.B.1. through XV.B.3. of this part.

XV.I.3.b. A proposed PAL level.

XV.I.3.c. The sum of the potential to emit of all emissions units under the PAL (with supporting documentation).

XV.I.3.d. Any other information the owner or operator wishes the Division to consider in determining the appropriate level for renewing the PAL.

XV.I.4. PAL adjustment.

In determining whether and how to adjust the PAL, the Division shall consider the options outlined in Sections XV.I.4.a. and XV.I.4.b. However, in no case may any such adjustment fail to comply with Section XV.I.4.c.

XV.I.4.a. If the emissions level calculated in accordance with Section XV.E. is equal to or greater than eighty percent of the PAL level, the Division may renew the PAL at the same level without considering the factors set forth in Section XV.I.4.b.; or

XV.I.4.b. The Division may set the PAL at a level that it determines to be more representative of the source's baseline actual emissions, or that it determines to be appropriate considering air quality needs, advances in control technology, anticipated economic growth in the area, desire to reward or encourage the source's voluntary emissions reductions, or other factors as specifically identified by the Division in its preliminary analysis or technical review document.

XV.I.4.c. Notwithstanding Sections XV.I.4.a. and XV.I.4.b. above,

XV.I.4.c.(i) If the potential to emit of the major stationary source or GHG-only source is less than the PAL, the Division shall adjust the PAL to a level no greater than the potential to emit of the source; and

XV.I.4.c.(ii) The Division shall not approve a renewed PAL level higher than the current PAL, unless the major stationary source or GHG-only source has complied with the provisions of Section XV.J. (increasing a PAL).

XV.I.5. If the compliance date for a State or Federal requirement that applies to the PAL source occurs during the PAL effective period, and if the Division has not already adjusted for such requirement, the PAL shall be adjusted at the time of PAL permit renewal or Title V permit renewal, whichever occurs first.

XV.J. Increasing a PAL during the PAL effective period.

XV.J.1. The Division may increase a PAL emission limitation only if the major stationary source or GHG-only source complies with the provisions in Sections XV.J.1.a. through XV.J.1.d. below.

XV.J.1.a. The owner or operator of the major stationary source or GHG-only source shall submit a complete application to request an increase in the PAL limit for a PAL major modification. Such application shall identify the emissions unit(s) contributing to the increase in emissions so as to cause the major stationary or GHG-only source's emissions to equal or exceed its PAL.

XV.J.1.b. As part of this application, the major stationary source or GHG-only source owner or operator shall demonstrate that the sum of the baseline actual emissions of the small emissions units, plus the sum of the baseline actual emissions of the significant and major emissions units assuming application of BACT equivalent controls, plus the sum of the allowable emissions of the new or modified emissions unit(s) exceeds the PAL. The level of control that would result from BACT equivalent controls on each significant or major emissions unit shall be determined by conducting a new BACT analysis at the time the application is submitted, unless the emissions unit is currently required to comply with a BACT or LAER requirement that was established within the preceding ten years. In such a case, the assumed control level for that emissions unit shall be equal to the level of BACT or LAER with which that emissions unit must currently comply.

XV.J.1.c. The owner or operator obtains a major NSR permit for all emissions unit(s) identified in Section XV.J.1.a., regardless of the magnitude of the emissions increase resulting from them (that is, no significant levels apply). These emissions unit(s) shall comply with any emissions requirements resulting from the major NSR process (for example, BACT or LAER), even though they have also become subject to the PAL or continue to be subject to the PAL.

XV.J.1.d. The PAL permit shall require that the increased PAL level shall be effective on the day any emissions unit that is part of the PAL major modification becomes operational and begins to emit the PAL pollutant.

XV.J.2. The Division shall calculate the new PAL as the sum of the allowable emissions for each modified or new emissions unit, plus the sum of the baseline actual emissions of the significant and major emissions units (assuming application of BACT equivalent controls as determined in accordance with Section XV.J.1.b.), plus the sum of the baseline actual emissions of the small emissions units.

XV.J.3. The PAL permit shall be revised to reflect the increased PAL level pursuant to the public notice requirements of Section XV.D. of this part.

XV.K. Monitoring requirements for PALs.

XV.K.1. General Requirements.

XV.K.1.a. Each PAL permit shall contain enforceable requirements for the monitoring system that accurately determines plant-wide emissions of the PAL pollutant in terms of mass per unit of time or CO2e per unit of time. Any monitoring system authorized for use in the PAL permit must be based on sound science and meet generally acceptable scientific procedures for data quality and manipulation. Additionally, the information generated by such system must meet minimum legal requirements for admissibility in a judicial proceeding to enforce the PAL permit.

XV.K.1.b. The PAL monitoring system must employ one or more of the four general monitoring approaches meeting the minimum requirements set forth in Sections XV.K.2.a. through XV.K.2.d. and must be approved by the Division.

XV.K.1.c. Notwithstanding Section XV.K.1.b., you may also employ an alternative monitoring approach that meets the requirements of Section XV.K.1.a. if approved by the Division.

XV.K.1.d. Failure to use a monitoring system that meets the requirements of this Section renders the PAL invalid.

XV.K.2. Minimum Performance Requirements for Approved Monitoring Approaches.

The following are acceptable general monitoring approaches when conducted in accordance with the minimum requirements in Sections XV.K.3. through XV.K.9:

XV.K.2.a. Mass balance calculations for activities using coatings or solvents;

XV.K.2.b. CEMS (as defined in Section I.B.14. of Part A);

XV.K.2.c. CPMS or PEMS (as defined in Sections I.B.16. and I.B.38., respectively, of Part A); and

XV.K.2.d. Published, verifiable emission factors

XV.K.3. Mass Balance Calculations.

An owner or operator using mass balance calculations to monitor PAL pollutant emissions from activities using coating or solvents shall meet the following requirements:

XV.K.3.a. Provide a demonstrated means of validating the published content of the PAL pollutant that is contained in or created by all materials used in or at the emissions unit;

XV.K.3.b. Assume that the emissions unit emits all of the PAL pollutant that is contained in or created by any raw material or fuel used in or at the emissions unit, if it cannot otherwise be accounted for in the process; and

XV.K.3.c. Where the vendor of a material or fuel, which is used in or at the emissions unit, publishes a range of pollutant content from such material, the owner or operator must use the highest value of the range to calculate the PAL pollutant emissions unless the Division determines there is site-specific data or a site-specific monitoring program to support another content within the range.

XV.K.4. CEMS.

An owner or operator using CEMS to monitor PAL pollutant emissions shall meet the following requirements:

XV.K.4.a. CEMS must comply with applicable Performance Specifications found in the Code of Federal Regulations Title 40, Part 60, Appendix B, and Part 75; and

XV.K.4.b. CEMS must sample, analyze and record data at least every fifteen minutes while the emissions unit is operating.

XV.K.5. CPMS or PEMS.

An owner or operator using CPMS or PEMS to monitor PAL pollutant emissions shall meet the following requirements:

XV.K.5.a. The CPMS or the PEMS must be based on current site specific data demonstrating a correlation between the monitored parameter(s) and the PAL pollutant emissions across the range of operation of the emissions unit; and

XV.K.5.b. Each CPMS or PEMS must sample, analyze, and record data at least every fifteen minutes, or at another less frequent interval approved by the Division, while the emissions unit is operating.

XV.K.6. Emission factors.

An owner or operator using emission factors to monitor PAL pollutant emissions shall meet the following requirements:

XV.K.6.a. All emission factors shall be adjusted, if appropriate, to account for the degree of uncertainty or limitations in the factors' development;

XV.K.6.b. The emissions unit shall operate within the designated range of use for the emission factor, if applicable; and

XV.K.6.c. If technically practicable, the owner or operator of a significant emissions unit that relies on an emission factor to calculate PAL pollutant emissions shall conduct validation testing to determine a site-specific emission factor within six months of PAL permit issuance, unless the Division determines that testing is not required.

XV.K.7. A source owner or operator must record and report maximum potential emissions without considering enforceable emission limitations or operational restrictions for an emissions unit during any period of time that there is no monitoring data, unless another method for determining emissions during such periods is specified in the PAL permit.

XV.K.8. Notwithstanding the requirements in Sections XV.K.3. through XV.K.7., where an owner or operator of an emissions unit cannot demonstrate a correlation between the monitored parameter(s) and the PAL pollutant emissions rate at all operating points of the emissions unit, the Division shall, at the time of permit issuance:

XV.K.8.a. Establish default value(s) for determining compliance with the PAL based on the highest potential emissions reasonably estimated at such operating point(s); or

XV.K.8.b. Determine that operation of the emissions unit during operating conditions when there is no correlation between monitored parameter(s) and the PAL pollutant emissions is a violation of the PAL.

XV.L. Re-validation.

All data used to establish the PAL pollutant must be re-validated through performance testing or other scientifically valid means approved by the Division. Such testing must occur at least once every five years after issuance of the PAL.

XV.M. Recordkeeping requirements.

XV.M.1. The PAL permit shall require an owner or operator to retain a copy of all records necessary to determine compliance with any requirement of Section XV. of this part and of the PAL, including a determination of each emissions unit's twelve-month rolling total emissions, for five years from the date of such record.

XV.M.2. The PAL permit shall require an owner or operator to retain a copy of the following records for the duration of the PAL effective period plus five years:

XV.M.2.a. A copy of the PAL permit application and any applications for revisions to the PAL; and

XV.M.2.b. Each annual certification of compliance pursuant to Part C of this regulation, and the data relied on in certifying the compliance.

XV.N. Reporting and notification requirements.

The owner or operator shall submit semi-annual monitoring reports and prompt deviation reports to the Division in accordance with the requirements of the applicable Title V permit and Section V.C.7. of Part C of this regulation. The reports shall meet the requirements in Sections XV.K.11.a. through XV.K.11.c. below.

XV.N.1. Semi-Annual Report.

The semi-annual report shall be submitted to the Division within thirty days of the end of each reporting period. This report shall contain the information required by the Title V permit, Section V.C.7.a. of Part C of this regulation, and Sections XV.N.1.a. through XV.N.1.g., below.

XV.N.1.a. The identification of owner and operator and the permit number.

XV.N.1.b. Total annual emissions (expressed on a mass-basis in tons per year, or expressed in tons per year CO2e) based on a twelve-month rolling total for each month in the reporting period recorded pursuant to Section XV.K.10.a.

XV.N.1.c. All data relied upon, including, but not limited to, any Quality Assurance or Quality Control data, in calculating the monthly and annual PAL pollutant emissions shall be made available upon request by the Division.

XV.N.1.d. A list of any emissions units modified or added to the major stationary source or GHG-only source during the preceding six-month period.

XV.N.1.e. The number, duration, and cause of any deviations or monitoring malfunctions (other than the time associated with zero and span calibration checks), and any corrective action taken.

XV.N.1.f. A notification of a shutdown of any monitoring system, whether the shutdown was permanent or temporary, the reason for the shutdown, the anticipated date that the monitoring system will be fully operational or replaced with another monitoring system, whether the emissions unit(s) monitored by the monitoring system continued to operate, and calculations of emissions from those units as provided by Section XV.K.7. of this part.

XV.N.1.g. A signed statement by the responsible official (as defined in Section I.B.40. of Part A of this regulation) certifying the truth, accuracy, and completeness of the information provided in the report.

XV.N.2. Deviation report.

The major stationary source or GHG-only source owner or operator shall promptly submit reports of any deviations or exceedance of the PAL requirements, including periods where no monitoring is available. A report submitted pursuant to Section V.C.7.b. of Part C of this regulation shall satisfy this reporting requirement. The deviation reports shall be submitted within the time limits prescribed by Section V.C.7.b. of Part C. The reports shall contain the following information:

XV.N.2.a. The identification of owner and operator and the permit number;

XV.N.2.b. The PAL requirement that experienced the deviation or that was exceeded;

XV.N.2.c. Emissions resulting from the deviation or the exceedance; and

XV.N.2.d. A signed statement by the responsible official (as defined in Section I.B.40. of Part A of this regulation) certifying the truth, accuracy, and completeness of the information provided in the report.

XV.N.3. Re-validation results

The owner or operator shall submit to the Division the results of any revalidation test or method within three months after completion of such test or method.

XV.O. If any provision of this Section, or the application of such provision to any person or circumstance, is held invalid, the remainder of this Section, or the application of such provision to persons or circumstances other than those as to which it is held invalid, shall not be affected thereby.

## PART E RESERVED FOR ENVIRONMENTAL MANAGEMENT SYSTEMS

Reserved for Environmental Management Systems

## PART F REGIONAL HAZE LIMITS - BEST AVAILABLE RETROFIT TECHNOLOGY (BART) AND REASONABLE PROGRESS (RP)

The provisions of Section VI (Regional Haze Determinations) and VII (MRR) of Regulation 3, Part F shall be incorporated into Colorado's Regional Haze State Implementation Plan. All other Sections of Regulation 3, Part F are State-Only.

The provisions of Part 51, Appendix Y, Title 40, of the Code of Federal Regulations (CFR), promulgated by the U.S. Environmental Protection Agency listed in this Section are hereby incorporated by reference by the Air Quality Control Commission and made a part of the Colorado Air Quality Control Commission Regulations as modified by the following Regulation Number 3, Part F. Materials incorporated by reference are those in existence as July 6, 2005 and do not include later amendments. The material incorporated by reference is available for public inspection during regular business hours at the Office of the Commission, located at 4300 Cherry Creek Drive South, Denver, Colorado 80246. The material incorporated by reference is also available through the United States Government Printing Office, online at www.gpo.gov/fdsys. Parties wishing to inspect these materials should contact the Technical Secretary of the Commission, located at the Office of the Commission.

### I. Applicability

The provisions of this regulation apply to existing stationary facilities (BART eligible sources), as defined in Section II.I. of this regulation, as well as to Reasonable Progress (RP) sources.

## II. Definitions

II.A. Adverse impact on visibility

Means visibility impairment that interferes with the management, protection, preservation, or enjoyment of the visitor's visual experience of the Federal Class I area. This determination must be made on a case-by-case basis taking into account the geographic extent, intensity, duration, frequency and time of visibility impairments, and how these factors correlate with (1) times of visitor use of the Federal Class I area, and (2) the frequency and timing of natural conditions that reduce visibility. This term does not include effects on integral vistas.

II.B. Available Technology

Means that a technology is licensed and available through commercial sales.

II.C. Applicable Technology

Means a commercially available control option that has been or may soon be deployed on the same or a similar source type or a technology that has been used on a pollutant-bearing gas stream that is the same or similar to the gas stream characteristics of the source.

II.D. Average Cost Effectiveness

Means the total annualized costs of control divided by annual emissions reductions (the difference between baseline annual emissions and the estimate of emissions after controls). For the purposes of calculating average cost effectiveness, baseline annual emissions means a realistic depiction of anticipated annual emissions for the source. The source or the Division may use state or federally enforceable permit limits or estimate the anticipated annual emissions based upon actual emissions from a representative baseline period.

II.E. BART Alternative

Means an alternative measure to the installation, operation, and maintenance of BART that will achieve greater reasonable progress toward national visibility goals than would have resulted from the installation, operation, and maintenance of BART at BART-eligible sources within industry source categories subject to BART requirements.

II.F. BART-eligible source

Means an existing stationary facility as defined in Section II.I.

II.G. Best Available Retrofit Technology (BART)

Means an emission limitation based on the degree of reduction achievable through the application of the best system of continuous emission reduction for each pollutant that is emitted by an existing stationary facility. The emission limitation must be established, on a case-by-case basis, taking into consideration the technology available, the costs of compliance, the energy and non-air quality environmental impacts of compliance, any pollution control equipment in use or in existence at the source or unit, the remaining useful life of the source or unit, and the degree of improvement in visibility which may reasonably be anticipated to result from the use of such technology.

II.H. Deciview

Means a measurement of visibility impairment. A deciview is a haze index derived from calculated light extinction, such that uniform changes in haziness correspond to uniform incremental changes in perception across the entire range of conditions, from pristine to highly impaired. The deciview haze index is calculated based on the following equation (for the purposes of calculating deciview, the atmospheric light extinction coefficient must be calculated from aerosol measurements):

Deciview haze index=$10 \ln_e (b_{ext}/10\ Mm^{-1})$

Where $b_{ext}$ = the atmospheric light extinction coefficient, expressed in inverse megameters ($Mm^{-1}$).

II.I. Existing stationary facility

Means any of the following stationary sources of air pollutants, including any reconstructed source, which was not in operation prior to August 7, 1962, and was in existence on August 7, 1977, and has the potential to emit 250 tons per year or more of any visibility impairing air pollutant. In determining potential to emit, fugitive emissions, to the extent quantifiable, must be counted.

II.I.1. Fossil-fuel fired steam electric plants of more than 250 million British thermal units (BTU) per hour heat input that generate electricity for sale

II.I.1.a. Boiler capacities shall be aggregated to determine the heat input of a plant

II.I.1.b. Includes plants that co-generate steam and electricity and combined cycle turbines

II.I.2. Coal cleaning plants (thermal dryers)

II.I.3. Kraft pulp mills

II.I.4. Portland cement plants

II.I.5. Primary zinc smelters

II.I.6. Iron and steel mill plants

II.I.7. Primary aluminum ore reduction plants

II.I.8. Primary copper smelters

II.I.9. Municipal incinerators capable of charging more than 250 tons of refuse per day

II.I.10. Hydrofluoric, sulfuric, and nitric acid plants

II.I.11. Petroleum refineries

II.I.12. Lime plants

II.I.13. Phosphate rock processing plants

Includes all types of phosphate rock processing facilities, including elemental phosphorous plants as well as fertilizer production plants

II.I.14. Coke oven batteries

II.I.15. Sulfur recovery plants

II.I.16. Carbon black plants (furnace process)

II.I.17. Primary lead smelters

II.I.18. Fuel conversion plants

II.I.19. Sintering plants

II.I.20. Secondary metal production facilities

Includes nonferrous metal facilities included within Standard Industrial Classification code 3341, and secondary ferrous metal facilities in the category “iron and steel mill plants.”

II.I.21. Chemical process plants

Includes those facilities within the 2-digit Standard Industrial Classification 28, including pharmaceutical manufacturing facilities

II.I.22. Fossil-fuel boilers of more than 250 million BTUs per hour heat input

II.I.22.a. Individual boilers greater than 250 million BTU/hr, considering federally enforceable operational limits

II.I.22.b. Includes multi-fuel boilers that burn at least fifty percent fossil fuels

II.I.23. Petroleum storage and transfer facilities with a capacity exceeding 300,000 barrels

II.I.23.a. 300,000 barrels refers to total facility-wide tank capacity for tanks put in place after August 7, 1962 and in existence on August 7, 1977

II.I.23.b. Includes gasoline and other petroleum-derived liquids.

II.I.24. Taconite ore processing facilities

II.I.25. Glass fiber processing plants

II.I.26. Charcoal production facilities

Includes charcoal briquette manufacturing and activated carbon production

II.J. Incremental Cost Effectiveness

Means the comparison of the costs and emissions performance level of a control option to those of the next most stringent option, as shown in the following formula:

Incremental Cost Effectiveness (dollars per incremental ton removed) = [(Total annualized costs of control option) - (Total annualized costs of next control option)] ÷ [(Next Control option annual emissions) - (control option annual emissions)]

II.K. In existence

Means that the owner or operator has obtained all necessary preconstruction approvals or permits required by Federal, State, or local air pollution emissions and air quality laws or regulations and either has (1) begun, or caused to begin, a continuous program of physical on-site construction of the facility or (2) entered into binding agreements or contractual obligations, which cannot be cancelled or modified without substantial loss to the owner or operator, to undertake a program of construction of the facility to be completed in a reasonable time.

II.L. In operation

Means engaged in activity related to the primary design function of the source.

II.M. Integral vista

Means a view perceived from within the mandatory Class I Federal area of a specific landmark or panorama located outside the boundary of the mandatory Class I Federal area.

II.N. Natural conditions

Means naturally occurring phenomena that reduce visibility as measured in terms of light extinction, visual range, contrast, or coloration.

II.O Plant

Means all emissions units at a stationary source.

II.P. Visibility-Impairing Air Pollutant

Includes the following:

II.P.1. Sulfur dioxide (SO2),

II.P.2 Nitrogen oxides (NOx) and

II.P.3. Particulate matter. (PM10 will be used as the indicator for particulate matter. Emissions of PM10 include the components of PM2.5 as a subset.).

**III. Sources required to Perform a BART Analysis**

Each source that the Division determines is BART-eligible and subject to BART shall complete a BART analysis under Section IV. The Division shall provide written notice to each source determined to be subject to BART. Within twenty calendar days of the mailing of such notice a source may appeal such determination to the Commission by filing a petition for a hearing with the Commission. Any such hearing shall be subject to Section VI. of the Procedural Rules.

III.A. Determining Potential to Emit for a BART Source

For the purposes of determining whether the potential to emit of an existing stationary source is greater than 250 tpy the potential emissions of visibility impairing pollutants from the existing stationary source shall include the emissions from all BART-eligible units which belong to the same industrial grouping, are located on one or more contiguous or adjacent properties, and are under the control of the same person (or persons under common control). Pollutant-emitting activities shall be considered as part of the same industrial grouping if they belong to the same Major Group (*i.e.*, which have the same two-digit code) as described in the Standard Industrial Classification Manual.

III.B. Identification of sources subject to BART

III.B.1. Identification of sources subject to BART shall be performed in accordance with EPA's guidelines for BART determinations under the regional haze rule 40 CFR Part 51, Appendix Y. A BART-eligible source described in Section III.A, above, is subject to BART unless valid air quality dispersion modeling demonstrates that the source will not cause or contribute to visibility impairment in any Class I area.

III.B.1.a. A single source that is responsible for a 1.0 deciview change or more is considered to “cause” visibility impairment in any Class I area.

III.B.1.b. A single source that is responsible for a 0.5 deciview change or more is considered to “contribute” visibility impairment in any Class I area.

III.B.1.c. A single source is exempt from BART if the 98th percentile daily change in visibility, as compared against natural background conditions, is less than 0.5 deciviews at all Class I federal areas for each year modeled and for the entire multi-year modeling period.

III.B.2. The Division will perform air quality dispersion modeling for each source identified as BART-eligible, for all visibility impairing pollutants, for class I areas. The modeling results will be provided to each source.

**IV. BART Analysis**

IV.A. Presumptive BART for Coal Fired Power Plants

IV.A.1. Plants with a Generating Capacity of 750 MW or Greater

BART-eligible coal fired power plants with a generating capacity of 750 MW or GREATER is presumed to be able to meet the presumptive limits. Regardless of whether or not a unit can meet the presumptive BART limits the source must complete a BART analysis.

IV.A.2. Other Coal Fired Power Plants

The Division shall use the presumptive BART limits of section IV.A.3. as guidelines and may establish a BART level for the unit either above or below the presumptive BART level based on the BART determination.

IV.A.3. Coal-Fired Electric Generating Units

IV.A.3.a. Sulfur Dioxide

Coal-Fired Electric Generating Units: 95 percent reduction or 0.15 lb SO2/mmBTU.

IV.A.3.b. Nitrogen Oxides

| Unit Type | Coal Type | $NO_X$ limit (lb/mm BTU) |
|---|---|---|
| Dry bottom Wall fired | Bituminous<br>Sub-bituminous<br>Lignite | 0.39<br>0.23<br>0.29 |
| Tangential Fired | Bituminous<br>Sub-bituminous<br>Lignite | 0.28<br>0.15<br>0.17 |
| Cell Burners | Bituminous<br>Sub-bituminous | 0.40<br>0.45 |
| Dry-turbo-fired | Bituminous<br>Sub-bituminous | 0.32<br>0.23 |
| Wet-bottom tangential-fired | Bituminous | 0.62 |

IV.B. Each source subject to BART pursuant to Section III shall submit a BART application for a construction permit, which shall include a BART analysis, a proposal for BART at the source and a justification for the BART proposal to the Division by August 1, 2006.

IV.B.1. The BART analysis must include, at a minimum:

IV.B.1.a. A list of the demonstrated and potentially applicable retrofit control options for the units subject to BART. Sources are not required to evaluate control options, which are less effective than the controls currently installed on the BART subject source or unit.

IV.B.1.b. A discussion of the technical feasibility of each of the technologies identified in Section IV.B.1.a. This discussion should include an analysis of whether the proposed technology is available and applicable. If the source determines that a technology is not technically feasible the discussion shall include a factual demonstration that the option is not commercially available or that unusual circumstances preclude its application to the emission unit.

IV.B.1.c. A ranking of all the technically feasible technologies identified in Section IV.B.1.b. The ranking shall take into account various emission performance characteristics of the technologies. The technologies should be ranked from lowest emissions to highest emissions for each pollutant and each emissions unit. The ranking should include a discussion of pollution control equipment in use at the unit, including upgrading existing equipment if technically feasible.

IV.B.1.d. An evaluation of the impacts of the technically feasible BART options. The impact evaluation shall include:

IV.B.1.d.(i). An estimate of the Average Cost Effectiveness of each of the control technologies identified as technically feasible in Section IV.B.1.b. This analysis shall specify the emissions unit being controlled, the design parameters for the emission controls and cost estimates based on those design parameters. The remaining useful life of the source or unit may be taken into account in the cost of the technologies. The remaining useful life is the difference between: (1) The date that controls will be put in place (capital and other construction costs incurred before controls are put in place can be rolled into the first year); and (2) The date the facility permanently stops operations. Where this affects the BART determination, this date should be assured by a federally- or State-enforceable restriction preventing further operation. The analysis must also include the energy and non-air quality environmental impacts of control options.

IV.B.1.d.(ii). An analysis of the incremental cost effectiveness. Before a control technology can be eliminated the source shall evaluate the incremental cost effectiveness in combination with the total cost effectiveness in order to justify elimination of a control option.

IV.B.1.d.(iii). An evaluation of the visibility impacts for each BART option according to modeling guidance provided by the Division.

IV.B.1.d.(iv). An evaluation of non-air quality impacts. The non-air quality impacts may include water use increases, solid waste disposal, or other adverse environmental impacts.

IV.B.1.d.(v). An evaluation of the energy impacts. The energy impact analysis should look at the energy requirements of the control technology and any energy penalties or benefits associated with the control. The analysis should also consider direct energy consumption and may address concerns over the use of locally scarce fuels or the use of locally or regionally available coal.

IV.B.1.d.(v).(1). The energy impacts analysis may consider whether there are relative differences between alternatives regarding the use of locally or regionally available coal, and whether a given alternative would result in significant economic disruption or unemployment.

IV.B.1.e. An evaluation and justification of the proposed averaging time to evaluate compliance with the proposed emission limitations.

IV.B.1.f. Coal-fired power plants may, in their discretion, include in the BART analysis an evaluation of representative characteristics (including nitrogen content) of coal from sources they reasonably expect to use, to the extent such characteristics tend to result in higher NOx emissions than coals of the same classification from alternative sources. The analysis also may consider whether a particular BART limit might lead the power plant not to use coal from a particular mine due to such coal characteristics, and the extent to which such a decision might result in economic disruption or unemployment at the mine or in nearby communities.

IV.B.1.g. Sources subject to a MACT standard may limit the analysis for those pollutants covered by the MACT to a discussion of new technologies that have become available since the promulgation of the MACT.

IV.B.2. Sources with a potential to emit of less than 40 tons per year of SO2 and NOx and less than 15 tpy of PM10 may exclude those pollutants from the BART determination.

IV.B.3. Selecting a best alternative

The source shall submit a proposal for BART at the source or unit(s), including a justification for selecting the technology proposed. The justification shall be based on the following factors: (1) the technology available; (2) the costs of compliance; (3) the energy and non-air environmental impacts of compliance; (4) any pollution control equipment in use at the source or unit(s); (5) the remaining useful life of the source or unit(s) and; (6) the degree of improvement in visibility which may reasonably be anticipated to result from the use of such technology.

IV.B.4. Schedules to comply with BART emissions limits

IV.B.4.a. The technology analysis shall include a schedule to comply with BART or a BART alternative as expeditiously as practicable following EPA approval of the state implementation plan for regional haze that incorporates such BART requirements. The source must comply with BART or BART alternative emissions limits no later than 5 years after approval of the state implementation plan by EPA for regional haze.

IV.B.4.b. A source or unit subject to BART may implement a BART alternative in lieu of BART if such BART alternative is authorized by the Division.

IV.C. BART Alternative

As an alternative to BART for a source or sources, the Division may approve a BART Alternative. If the Division approves source grouping as a BART Alternative, only sources (including BART-eligible and non-BART eligible sources) within the same source category (as defined by SIC or NAICS code) within the same airshed may be grouped together.

IV.C.1. If a Source (s) proposes a BART Alternative, the resultant emissions reduction and visibility impacts must be compared with those that would result from the BART options evaluated for the source(s).

IV.C.2. Source (s) proposing a BART alternative shall include in the BART analysis an analysis and justification of the averaging period and method of evaluating compliance with the proposed emission limitation.

IV.D. Emission limits

IV.D.1. Coal-Fired Electric Generating Units

Compliance with the emission limitation is determined on a 30-day rolling average basis for SO2 and NOx, or may be determined by the Division based on the BART analysis submitted by the source. The emission limit shall be included in the facility's permit.

IV.D.2. Other Sources Subject to BART

The Division will establish emission limits with averaging times consistent with established reference methods and include the limit in the facility's permit.

IV.E. A source that has installed BART for regional haze or implemented a Division approved BART alternative for regional haze is exempted from the imposition of further controls pursuant to regional haze BART with respect to those pollutants that are controlled through BART or the BART alternative for Regional Haze and is exempted from the imposition of further controls necessary for reasonable progress during the first reasonable progress planning period. Sources may be subject to additional controls or emission reductions based on reasonable progress requirements in planning periods beyond the first planning period under the regional haze State Implementation Plan.

IV.F. Division Review and Approval

IV.F.1. The Division shall review and approve, disapprove or amend the proposed BART technology or BART alternative, including the emission limit, schedule for compliance for the facility, and averaging period. The Division shall consider additional information both submitted and not submitted by the source that is deemed relevant. The Division shall submit its BART determination to the Commission for review and approval.

IV.F.2. If two or more sources are grouped together pursuant to Section IV.C. the Division shall establish recordkeeping and reporting requirements sufficient to determine that the sources meet the BART alternative emission limits.

IV.F.3. Any source seeking to modify the BART determination for that facility must submit a new BART analysis for review by the Division.

**V. Challenge of Division BART Determinations and Enforceable Agreements.**

V.A. Persons affected or aggrieved by a BART determination may challenge the decision of the Commission pursuant to Article 4 of Title 24, C.R.S.

**VI. Regional Haze Determinations**

VI.A. BART Determinations

VI. A.1. The provisions of this Section VI.A of Regulation Number 3, Part F shall be incorporated into Colorado's Regional Haze State Implementation Plan.

VI.A.2. The sources listed below shall not emit or cause to be emitted nitrogen oxides (NOx), sulfur dioxide (SO2), or particulate in excess of the following limits:

**BART Determinations for Colorado Sources**

| Unit | NOx Emission Limit | SO2 Emission Limit | Particulate Emission Limit |
|---|---|---|---|
| CENC Unit 4 | 0.37 lb/MMBtu (30-day rolling average)<br>or<br>0.26 lb/MMBtu Combined Average for Units 4 and 5 (30-day rolling average) | 1.0 lb/MMBtu<br>(30-day rolling average) | 0.07 lb/MMBtu |

| | | | |
|---|---|---|---|
| CENC Unit 5 | 0.19 lb/MMBtu (30-day rolling average)<br>or<br>0.26 lb/MMBtu Combined Average for Units 4 and 5 (30-day rolling average) | 1.0lb/MMBtu<br>(30-day rolling average) | 0.07 lb/MMBtu |
| Craig Unit 1 | * | 0.11 lb/MMBtu<br>(30-day rolling average) | 0.03 lb/MMBtu |
| Craig Unit 2 | 0.08 lb/MMBtu<br>(30-day rolling average) | 0.11 lb/MMBtu<br>(30-day rolling average) | 0.03 lb/MMBtu |

*Refer to VI.D. for requirements

| **Unit** | **NOx Emission Limit** | **SO2 Emission Limit** | **Particulate Emission Limit** |
|---|---|---|---|
| Comanche Unit 1 | 0.20 lb/MMBtu<br>(30-day rolling average)<br>0.15 lb/MMBtu<br>(combined annual average for units 1 & 2) | 0.12 lb/MMBtu<br>(individual unit 30-day rolling average)<br>0.10 lb/MMBtu<br>(combined annual average for units 1 & 2) | 0.03 lb/MMBtu |
| Comanche Unit 2 | 0.20 lb/MMBtu<br>(30-day rolling average)<br>0.15 lb/MMBtu<br>(combined annual average for units 1 & 2) | 0.12 lb/MMBtu<br>(individual unit 30-day rolling average)<br>0.10 lb/MMBtu<br>(combined annual average for units 1 & 2) | 0.03 lb/MMBtu |
| Hayden Unit 1 | 0.08lb/MMBtu<br>(30-day rolling average) | 0.13 lb/MMBtu<br>(30-day rolling average) | 0.03 lb/MMBtu |

| | | | |
|---|---|---|---|
| Hayden Unit 2 | 0.07 lb/MMBtu<br>(30-day rolling average) | 0.13 lb/MMBtu<br>(30-day rolling average) | 0.03 lb/MMBtu |
| Martin Drake Unit 5 | 0.31 lb/MMBtu<br>(30-day rolling average) | 0.26 lb/MMBtu<br>(30-day rolling average) | 0.03 lb/MMBtu |
| Martin Drake Unit 6 | 0.31lb/MMBtu<br>(30-day rolling average) | 0.13lb/MMBtu<br>(30-day rolling average) | 0.03 lb/MMBtu |
| Martin Drake Unit 7 | 0.29 lb/MMBtu<br>(30-day rolling average) | 0.13lb/MMBtu<br>(30-day rolling average) | 0.03 lb/MMBtu |
| CEMEX – Lyons Kiln | 255.3 lbs/hr<br>(30-day rolling average)<br>901.0 tons/year<br>(12-month rolling average) | 25.3 lbs/hr<br>(12-month rolling average)<br>95.0 tons/yr<br>(12-month rolling average) | 0.275 lb/ton of dry feed 20% opacity |
| CEMEX – Lyons Dryer | 13.9 tons/yr | 36.7 tons/yr | 22.8 tons/yr<br>10% opacity |

VI.A.3. Each source listed in the above tables must comply with the above limits and averaging times as expeditiously as practicable, but in no event later than five years after EPA approval of Colorado's state implementation plan for regional haze, which was January 30, 2013 with the exception of Craig Unit 1, or relevant component thereof. Each source listed in the above tables must maintain control equipment or operational practices required to comply with the above limits and averaging times, and establish procedures to ensure that such equipment or operational practices are properly operated and maintained.

VI.A.4. Except for Craig Unit 1, the sources shall submit to the Division a proposed compliance schedule within sixty days after EPA approves the BART portion of the Regional Haze SIP. The Division shall publish these proposed schedules and provide for a thirty-day public comment period following publication. The Division shall publish its final determinations regarding the proposed schedules for compliance within sixty days after the close of the public comment period and will respond to all public comments received.

VI.B. Reasonable Progress Determinations

VI.B.1. The provisions of this Section VI.B of Regulation Number 3, Part F shall be incorporated into Colorado's Regional Haze State Implementation Plan.

VI.B.2. The sources listed below shall not emit or cause to be emitted nitrogen oxides (NOx), sulfur dioxide (SO2), or particulate in excess of the following limits:

| **RP Determinations for Colorado Sources** | | | |
|---|---|---|---|
| **Emission Unit** | **NOx Emission Limit** | **SO2 Emission Limit** | **Particulate Emission Limit** |
| **Rawhide**<br>Unit 101 | 0.145 lb/MMBtu<br>(30-day rolling average) | 0.11 lb/MMBtu<br>(30-day rolling average) | 0.03 lb/MMBtu |
| **CENC**<br>Unit 3 | 246 tons per year<br>(12-month rolling total) | 1.2 lb/MMBtu | 0.07 lb/MMBtu |
| **Nixon** | 0.21 lb/MMBtu<br>(30-day rolling average) | 0.11 lb/MMBtu<br>(30-day rolling average) | 0.03 lb/MMBtu |
| **Clark**<br>Units 1 & 2<br>Shutdown 12/31/2013 | Shutdown 12/31/2013 | Shutdown 12/31/2013 | Shutdown 12/31/2013 |
| **Holcim - Florence**<br>Kiln | 2.73 lbs/ton clinker<br>(30-day rolling average)<br>2,086.8 tons/year | 1.30 lbs/ton clinker<br>(30-day rolling average)<br>721.4 tons/year | 246.3 tons/year |

| | | | |
|---|---|---|---|
| **Nucla** | 0.5 lb/MMBtu<br><br>(30-day rolling average)* | 0.4 lb/MMBtu<br><br>(30-day rolling average) | 0.03 lb/MMBtu |

*Refer to VI.E. for requirements

| **RP Determinations for Colorado Sources** | | | |
|---|---|---|---|
| **Emission Unit** | **NOx Emission Limit** | **SO2 Emission Limit** | **Particulate Emission Limit** |
| **Craig**<br><br>Unit 3 | 0.28 lb/MMBtu<br><br>(30-day rolling average) | 0.15 lb/MMBtu<br><br>(30-day rolling average) | 0.013 lb/MMBtu filterable PM<br><br>0.012 lb/MMBtu filterable PM10 |
| **Cameo**<br><br>Shutdown 12/31/2011 | Shutdown 12/31/2011 | Shutdown 12/31/2011 | Shutdown 12/31/2011 |

VI.B.3. Each source listed in the above table must comply with the above limits and averaging times as expeditiously as practicable, but in no event later than December 31, 2017, except for Nucla. Each source listed in the above table must maintain control equipment or operational practices required to comply with the above limits and averaging times, and establish procedures to ensure that such equipment or operational practices are properly operated and maintained.

VI.B.4. Except for Nucla, the sources shall submit to the Division a proposed compliance schedule within sixty days after EPA approves the RP portion of the Regional Haze SIP. The Division shall publish these proposed schedules and provide for a thirty-day public comment period following publication. The Division shall publish its final determinations regarding the proposed schedules for compliance within sixty days after the close of the public comment period and will respond to all public comments received.

VI.C. Public Service Company of Colorado (PSCo) BART Alternative Program

VI.C.1. The provisions of this Section VI.C of Regulation Number 3, Part F (with the exception of the SO2 cap of subsection VI.C.4) shall be incorporated into Colorado's Regional Haze State Implementation Plan.

VI.C.2. The sources listed below shall not emit or cause to be emitted nitrogen oxides (NOx), sulfur dioxide (SO2), or particulate in excess of the following limits, after the following compliance dates:

| **BART Alternative Program Determinations for PSCo Sources** | | | |
|---|---|---|---|
| **Emission Unit** | **NOx Emission Limit** | **SO2 Emission Limit** | **Particulate Emission Limit** |
| **Cherokee ***<br>Unit 1<br>Shutdown No later than<br>7/1/2012 | 0<br>Shutdown No later than 7/1/2012 | 0<br>Shutdown No later than 7/1/2012 | 0<br>Shutdown No later than 7/1/2012 |
| **Cherokee**<br>Unit 2<br>Shutdown 12/31/2011 | 0<br>Shutdown 12/31/2011 | 0<br>Shutdown 12/31/2011 | 0<br>Shutdown 12/31/2011 |
| **Cherokee**<br>Unit 3<br>Shutdown No later than 12/31/2016 | 0<br>Shutdown No later than 12/31/2016 | 0<br>Shutdown No later than 12/31/2016 | 0<br>Shutdown No later than 12/31/2016 |
| **Cherokee**<br>Unit 4 | 0.12 lb/MMBTU<br>(30-day rolling average) by 12/31/2017<br>Natural Gas Operation 12/31/2017 | 7.81 tpy<br>(rolling 12 month average)<br>Natural Gas Operation 12/31/2017 | 0.03 lbs/MMBtu<br>Natural Gas Operation 12/31/2017 |
| **Valmont**<br>Unit 5<br>Shutdown 12/31/2017 | 0<br>Shutdown 12/31/2017 | 0<br>Shutdown 12/31/2017 | 0<br>Shutdown 12/31/2017 |

| | | | |
|---|---|---|---|
| **Pawnee** | 0.07 lb/MMBTU<br><br>(30-day rolling average) by 12/31/2014 | 0.12 lbs/MMBtu<br><br>(30-day rolling average) by 12/31/2014 | 0.03 lbs/MMBtu |
| **Arapahoe****<br><br>Unit 3<br><br>Shutdown 12/31/2013 | 0<br><br>Shutdown 12/31/2013 | 0<br><br>Shutdown 12/31/2013 | 0<br><br>Shutdown 12/31/2013 |
| **Arapahoe**<br><br>Unit 4 | 600 tpy on<br><br>(rolling 12 month average)<br><br>Natural Gas operation12/31/2014 | 1.28 tpy<br><br>(rolling 12 month average)<br><br>Natural Gas operation 12/31/2014 | 0.03 lbs/MMBtu<br><br>Natural Gas operation 12/31/2014 |

* 500 tpy NOx will be reserved from Cherokee Station for netting or offsets

** 300 tpy NOx will be reserved from Arapahoe Station for netting or offsets for additional natural gas generation

VI.C.3. Each source listed in the above table must either shut down or comply with the above limits and averaging times no later than the compliance date set forth in the above table. Each source listed in the above table must maintain any applicable control equipment required to comply with the above limits and averaging times, and establish procedures to ensure that such equipment is properly operated and maintained.

VI.C.4. In addition to the above listed emission limits and compliance dates, between 1/1/2013 and 12/31/2015, Cherokee Units 3 and 4 and Valmont, considered as a whole, shall not emit in excess of 4,200 tons of SO2 per year as determined on a calendar year annual basis. Between 1/1/2016 and 12/31/2017 Cherokee Unit 4 and Valmont considered as a whole, shall not emit in excess of 3,450 tons of SO2 per year as determined on a calendar year annual basis.

VI.D. Craig Unit 1 Additional Compliance Requirements

VI.D.1. Craig Unit 1 will:

VI.D.1.a. Close on or before December 31, 2025; or

VI.D.1.b. Alternatively, cease burning coal no later than August 31, 2021, with the option to convert the unit to natural-gas firing on or before August 31, 2023.

VI.D.1.b.(i) If Craig Unit 1 is converted to natural-gas firing, the Unit will meet a NOx emission limit of no more than 0.07 lb/MMBtu 30-day rolling average applicable after August 31, 2021.

VI.D.2. The owner-operator of Craig Unit 1 will notify the Division in writing on or before February 28, 2021 whether the unit will cease operation or convert to gas.

VI.D.3. Craig Unit 1 will meet a NOx emission limit of 0.28 lb/MMBtu 30-day rolling average going forward from January 1, 2017 (first compliance date January 31, 2017), until closure or converting to natural gas.

VI.D.4. Craig Unit 1 will meet an annual NOx limit of 4,065 tons per year by December 31, 2019 on a calendar year basis beginning in 2020.

VI.E Nucla Compliance Requirements

VI.E.1 Nucla Station will close on or before December 31, 2022.

VI.E.2. Nucla Station will meet an annual NOx limit of 952 tons per year by January 1, 2020 on calendar year basis beginning in 2020.

**VII. Monitoring, Recordkeeping, and Reporting for Regional Haze Limits**

The provisions of this Section VII of Regulation 3, Part F shall be incorporated into Colorado's Regional Haze State Implementation Plan.

Federal Regulations Adopted by Reference

The following regulations promulgated by the United States Environmental Protection Agency (EPA) were previously adopted by the Colorado Air Quality Control Commission and are thereby already incorporated by reference:

40 CFR Part 60 and Appendices (As incorporated by reference within Commission Regulation Number 6, 5 CCR 1001-8)

40 CFR Part 63, Subpart A - National Emission Standards for Hazardous Air Pollutants General Provisions and Subpart LLL - National Emission Standards for Hazardous Air Pollutants From the Portland Cement Manufacturing Industry (As incorporated by reference within Commission Regulation Number 8, Part A, 5 CCR 1001-10).

40 CFR Part 64 (As incorporated by reference within Commission Regulation Number 3, Part C Section XIV., 5 CCR 1001-5)

40 CFR Part 75 including Performance Specifications and Appendices (As incorporated by reference within Commission Regulation Number 6, 5 CCR 1001-8)

VII.A. Definitions

VII.A.1. "BART alternative program unit" means any unit subject to a Regional Haze emission limit contained in the Table in Regulation Number 3, Part F, Section VI.C.

VII.A.2. "BART unit" means any unit subject to a Regional Haze emission limit contained in the Table in Regulation Number 3, Part F, Section VI.A.

VII.A.3. "Continuous emission monitoring system" or "CEMS" means the equipment required by Regulation Number 3, Part F, Section VII, to sample, analyze, measure, and provide (using an automated data acquisition and handling system (DAHS)), a permanent record of SO2 or NOx emissions, other pollutant emissions, diluents, or stack gas volumetric flow rate.

VII.A.4. "Operating day" means any twenty-four-hour period between midnight and the following midnight during which any fuel is combusted at any time in a BART unit, BART alternative program unit, or Reasonable Progress unit.

VII.A.5. "Reasonable Progress unit" or "RP unit" means any unit subject to a Regional Haze emission limit contained in the Table in Regulation Number 3, Part F, Section VI.B.

VII.A.6. "Regional Haze emission limit" means any of the emission limits specified in the Tables contained in Regulation Number 3, Part F, Section VI.

VII.B. Monitoring/Compliance Determination: SO2 and NOx Regional Haze Limits

VII.B.1. BART, RP, and BART alternative program units with SO2 and NOx CEMS.

VII.B.1.a. All Boilers, except CENC and Clark boilers.

The owner or operator of a boiler subject to this section shall comply with the Part 75 monitoring and recordkeeping requirements as incorporated by reference into this regulation with the exception of the continuous emission monitoring system (CEMS) data substitution and bias adjustment requirements.

At all times after the compliance deadline specified in Regulation Number 3, Part F, Section VI.A.3., VI.B.3. or VI.C.3., the owner/operator of each BART, RP, or BART alternative program unit shall maintain, calibrate, and operate a CEMS, in full compliance with the requirements found at 40 CFR Part 75 not excluded above, to accurately measure from such unit SO2, NOx, diluents, and stack gas volumetric flow rate as such parameters are relevant to the applicable emission limit. The CEMS shall be used to determine compliance with the SO2 and NOx Regional Haze emission limits for each such unit. Such limits are expressed in units of pounds per million Btu. The owner/operator shall calculate emissions in the applicable units.

In determining compliance with the SO2 and NOx Regional Haze limits, all periods of emissions shall be included, including startups, shutdowns, emergencies, and malfunctions.

VII.B.1.a.(i). Pounds Per Million Btu Regional Haze Limits

For any hour in which fuel is combusted in the BART, RP, or BART alternative program unit, owner/operator shall calculate hourly average SO2 and NOx concentrations in pounds per million Btu at the CEMS in accordance with the requirements of 40 CFR Part 75 except for Part 75 requirements excluded by Section VII. B.1.a. These hourly averages shall then be used to determine compliance in accordance with the particular limit's averaging period, as follows:

VII.B.1.a.(i).(1). Regional Haze limits with a 3-hour averaging period: Emissions shall be calculated on a 3-hour rolling average basis. At the end of each operating hour, the owner/operator shall calculate and record a new 3-hour average emission rate in lb/MMBtu from the arithmetic average of the valid hourly emission rates from the CEMS for the previous three operating hours. (An operating hour is any hour in which fuel is combusted for any time in the unit.)

VII.B.1.a.(i).(2). Regional Haze limits with a 30-day averaging period: Before the end of each operating day, the owner/operator shall calculate and record the 30-day rolling average emission rate in lb/MMBtu from all valid hourly emission values from the CEMS for the previous 30 operating days.

VII.B.1.a.(i).(3). Regional Haze limits with a 90-day averaging period: Before the end of each operating day, the owner/operator shall calculate and record the 90-day rolling average emission rate in lb/MMBtu from all valid hourly emission values from the CEMS for the previous 90 operating days.

VII.B.1.a.(i).(4). Regional Haze limits with a 12-month averaging period: Before the end of each month, the owner/operator shall calculate and record the 12-month rolling average emission rate in lb/MMBtu from all valid hourly emission values from the CEMS for the previous 12 months.

VII.B.1.a.(i).(5). Regional Haze limits with an annual calendar averaging period: Emissions shall be calculated on a calendar year basis. Within 30 days after the end of each calendar year, the owner/operator shall calculate and record a new emission rate in lb/MMBtu from the arithmetic average of all valid hourly emission rates from the CEMS for the preceding year.

VII.B.1.a.(i).(6). Comanche Units 1 and 2 Regional Haze combined annual average limits. The combined annual limitations for NOX and SO2 are on a 365-operating day rolling average. Before the end of each operating day, the owner/operator shall calculate and record an annual rolling average using data from the previous 365 operating days in accordance with the following equation.

Combined emission rate (lb/MMBtu) = [(ER1)(HI1) + (ER2)(HI2)]/(HI1 + HI2)

Where: ER1 = average emission rate over the 365 operating day period. This is an average of all valid hours within the 365 operating day period for Unit 1.

HI1 = total heat input over the 365 operating day period for Unit 1.

ER2 = average emission rate over the 365 operating day period. This is an average of all valid hours within the 365 operating day period for Unit 2.

HI2 = total heat input over the 365 operating day period for Unit 2.

VII.B.1.b. Portland Cement Kilns and CENC and Clark Boilers: At all times after the compliance deadline specified in Regulation Number 3, Part F, Section VI.A.3., or VI.B.3., the owner/operator of each BART or RP unit shall maintain, calibrate and operate a CEMS in full compliance with the requirements in 40 CFR Part 60 Section 60.13 and Part 60 Appendices A, B and F to accurately measure SO2, NOX and diluents, if diluent is required. The CEMS shall be used to determine compliance with the SO2 and NOX Regional Haze emission limits for each such unit. For particular units, such limits are expressed in units of pounds per hour, tons per year, pounds per ton clinker or pounds per million Btu. The owner/operator shall calculate emissions in the applicable units. In determining compliance with the SO2 and NOX Regional Haze limits, all periods of emissions shall be included, including startups, shutdowns, emergencies and malfunctions.

VII.B.1.b.(i). Pounds per Hour and Tons per Year Regional Haze Limits and Pounds per Million Btu Regional Haze Limits.

For any hour in which fuel is combusted in the BART or RP unit, the owner/operator shall calculate hourly NOx and SO2 emissions in the appropriate units (lbs/hr) or (lbs/MMbtu) in accordance with the provisions in 40 CFR Part 60. These hourly values shall be used to determine compliance in accordance with the particular limits averaging time, as follows:

VII.B.1.b.(i).(1). Pounds per Hour or Pounds per Million Btu Regional Haze Limits on a 30-day rolling average, Before the end of each operating day, the owner/operator shall calculate and record the 30-day rolling average emission rate in lb/MMBtu or lb/hr from all valid hourly emission values from the CEMS for the previous 30 operating days.

VII.B.1.b.i.(2). Pounds per Hour on a 12-month rolling average. Before the end of each month, the owner/operator shall calculate and record the 12-month rolling average emission rate in lb/hr from all valid hourly emission values from the CEMS for the previous 12 months.

VII.B.1.b.i.(3). Tons per year Regional Haze Limits on a 12-month rolling average. Before the end of each month, the owner/operator shall calculate and record the total emissions in tons/yr from all valid hourly emission values from the CEMS for the previous 12 months.

VII.B.1.b.(ii). 30-Day Rolling Average Pounds per Ton Clinker Regional Haze Limits. Hourly clinker production shall be determined in accordance with the requirements in 40 CFR Part 60 Subpart F Section 60.63(b). An operating day includes all valid data obtained in any daily 24-hour period during which the kiln operates and excludes any measurements made during the daily 24-hour period when the kiln was not operating. The 30-operating day rolling emission rate of NOx and SOx shall be calculated and recorded as the total of all hourly emissions data for a cement kiln in the preceding 30 operating days, divided by the total tons of clinker produced in that kiln during the same 30-day operating period in accordance with the equation in 40 CFR Part 60 Subpart F Section 60.64(c).

VII.B.1.b.(iii). CENC Units 4 and 5 NOX Regional Haze limits:

For any hour in which fuel is combusted in CENC Unit 4 or Unit 5, the owner/operator shall calculate hourly NOX emissions in the appropriate units (lbs/MMbtu) in accordance with the provisions in 40 CFR Part 60. These hourly values shall be used to determine compliance with the Regional Haze limits, as follows:

VII.B.1.b.(iii).(1). Individual unit pound per Million Btu on a 30-day rolling average Regional Haze Limit: Before the end of each operating day, the owner/operator shall calculate and record the 30-day rolling average emission rate in lb/MMBtu from all valid hourly emission values from the CEMS for the previous 30 operating days, OR

VII.B.1.b.(iii).(2). Combined units 4 and 5 lbs/MMbtu 30-day rolling average Regional Haze Limit: Before the end of each operating day, the owner/operator shall calculate and record a 30-day rolling average using data from the previous 30 operating days in accordance with the following equation:

Average ER = [(ER4)(HI4)+(ER5)(HI5)] / [(HI4)+(HI5)]

Where:

ER4 = average NOX emission rate, in pounds per MMbtu over the 30 day period. This is an average of all valid hours within the 30 operating day period for Unit 4.

ER5 = average NOX emission rate, in pounds per MMbtu over the 30 day period. This is an average of all valid hours within the 30 operating day period for Unit 5.

HI4 = Total heat input over the 30 operating day period for Unit 4.

HI5 = Total heat input over the 30 operating day period for Unit 5.

VII.B.1.b.(iii).(3). The owner or operator shall indicate in the excess emission reports required by Section VII.E of this Part F, which compliance demonstration method has been followed for the reporting period.

VII.B.2. BART and RP Units without NOX and SO2 CEMS.

VII.B.2.a. CENC Unit 3. Compliance with the SO2 limitations shall be determined by sampling and analyzing each shipment of coal for the sulfur and heat content using the appropriate ASTM Methods. In lieu of sampling, vendor receipts may be used provided the sampling and analysis was conducted in accordance with the appropriate ASTM Method. Each sample or vendor receipt must indicate compliance with the SO2 limitation. Compliance with the annual NOx limits shall be monitored by recording fuel consumption and calculating emissions monthly using the appropriate AP-42 emission factor. Monthly emissions shall be calculated by the end of the subsequent month and shall be used in a rolling twelve month total to monitor compliance with the annual limitations. Each month a new twelve month total shall be calculated using the previous 12 months data. [*Note: CENC Unit 3 is not subject to annual SO2 limits.]

VII.B.2.b. CEMEX Dryer. Unless performance tests were completed within the previous 6 months, within 60 days of the compliance deadline specified in Regulation Number3, Part F Section VI.A.3, the owner/operator shall conduct a stack test to measure NOX and SO2 emissions in accordance with the appropriate EPA test methods. Frequency of testing thereafter shall be every five years. Each test shall consist of three test runs, with each run at least 60 minutes in duration.

In addition to the stack tests described above, compliance with the annual NOx and SO2 limits shall be monitored by calculating emissions monthly using the emission factors (in lb/hr) determined from the most recent Division-approved stack test and hours of operation for the month. Monthly emissions shall be calculated by the end of the subsequent month and used in a twelve month rolling total to monitor compliance with the annual limitations. Each month a new twelve month total shall be calculated using the previous 12 months' data.

VII.C. Monitoring/Compliance Determination: Particulate Regional Haze Limits

VII.C.1. Particulate Regional Haze Limits for all boilers except CENC and Clark boilers

Unless particulate compliance testing was completed within the previous 6 months, within 60 days of the compliance deadline specified in Regulation Number 3, Part F, Section VI.A.3., VI.B.3., or VI.C.3., the owner/operator shall conduct a stack test to measure particulate emissions in accordance with the requirements and procedures set forth in EPA Test Method 5 as set forth in 40 CFR Part 60, Appendix A. Stack testing for particulate matter shall be performed annually, except that: (1) if any test results indicate emissions are less than or equal to 50% of the emission limit, another test is required within five years; (2) if any test results indicate emissions are more than 50%, but less than or equal to 75% of the emission limit, another test is required within three years; and (3) if any test results indicate emissions are greater than 75% of the emission limit, an annual test is required until the provisions of (1) or (2) are met. A test run shall consist of three test runs, with each run at least 120 minutes in duration. Test results shall be converted to the applicable units and compliance will the based on the average of the three test runs.

In addition, to the stack tests described above, the owner/operator shall monitor compliance with the particulate matter limits in accordance with the applicable compliance assurance monitoring plan developed and approved in accordance with 40 CFR Part 64.

VII.C.2. Portland Cement Plant Particulate Regional Haze Limits.

VII.C.2.a. Kilns. Compliance with the particulate matter limitations shall be monitored using a PM CEMS that meets the requirements in 40 CFR Part 63 Subpart LLL. The owner or operator shall calculate emissions in the applicable units. If a PM CEMS is used to monitor compliance with the PM limits, the opacity limits specified in this Part F do not apply.

In the event that the provisions in 40 CFR Part 63 Subpart LLL are revised, stayed or vacated, such that a PM CEMS is not required, compliance with the PM limitations shall be monitored by conducting stack tests in accordance with the requirements of Section VII.C.3. except that the results of the test shall be converted to the appropriate units (lb/ton clinker or lb/ton dry feed) and compliance will be based on the average of three test runs.

In addition, if no PM CEMS is required, as discussed in the above paragraph, the opacity limits specified in this Part F do apply. In order to monitor compliance with the opacity limit, the owner or operator shall install, calibrate, maintain, and continuously operate a COM located at the outlet of the PM control device to continuously monitor opacity. The COM shall be installed, maintained, calibrated, and operated as required by 40 CFR Part 63, Subpart A, and according to PS-1 of 40 CFR Part 60, Appendix B

VII.C.2.b. Dryers. Performance tests shall be conducted in accordance with the requirements in Section VII.C.3. Opacity monitoring shall be conducted in accordance with the requirements in 40 CFR Part 63 Subpart LLL.

VII.C.3. Particulate Regional Haze Limits for the CENC and Clark boilers and the CEMEX dryer. Within 60 days of the compliance deadline specified in Regulation Number 3, Part F, Section VI.A.3. or VI.B.3., the owner/operator shall conduct a stack test to measure particulate emissions in accordance with the requirements and procedures set forth in EPA Test Method 5, 5B, 5D or 17, as appropriate, as set forth in 40 CFR Part 60, Appendix A. Stack testing for particulate matter shall be performed annually, except that: (1) if any test results indicate emissions are less than or equal to 50% of the emission limit, another test is required within five years; (2) if any test results indicate emissions are more than 50%, but less than or equal to 75% of the emission limit, another test is required within three years; and (3) if any test results indicate emissions are greater than 75% of the emission limit, an annual test is required until the provisions of (1) or (2) are met. Each test shall consist of three test runs, with each run at least 60 minutes in duration.

In addition, to the stack tests described above, compliance with the annual limitations (ton/yr limits) applicable to the Clark boilers and CEMEX dryer shall be monitored by calculating emissions monthly using the emission factors (in lb/hr) determined from the most recent Division-approved stack test and hours of operation for the month. Monthly emissions shall be calculated by the end of the subsequent month and used in a twelve month rolling total to monitor compliance with the annual limitations. Each month a new twelve month total shall be calculated using the previous 12 months' data.

In addition to the stack tests described above, the owner/operator shall monitor compliance with the particulate matter limits in accordance with the applicable compliance assurance monitoring plan developed and approved in accordance with 40 CFR Part 64.

VII.D. Recordkeeping

Owner/operator shall maintain the following records for at least five years:

VII.D.1. All CEMS data as required in the applicable regulation, stack test data, and data collected pursuant to the CAM plan, including the date, place, and time of sampling, measurement, or testing; parameters sampled, measured, or tested and results; the company, entity, or person that performed the testing, if applicable; and any field data sheets from testing.

VII.D.2. Records of quality assurance and quality control activities for emissions measuring systems including, but not limited to, any records required by 40 CFR Part 60, 63, or 75.

VII.D.3. Any other records required by 40 CFR parts 60, Subpart F, Section 60.65, 63, Subpart LLL, 64 or 75.

VII.E. Reporting requirements

The owner/operator of a BART, RP or BART alternative program unit shall submit semi-annual excess emissions reports no later than the 30th day following the end of each semi-annual period unless more frequent reporting is required. Excess emissions means emissions that exceed the Regional Haze emissions limits. Excess emission reports shall include the information specified in 40 CFR Part 60, Section 60.7(c).

The owner/operator of a BART, RP or BART alternative program unit shall submit reports of any required performance stack tests for particulate matter, to the Division within 60 calendar days after completion of the test.

The owner/operator shall also submit semi-annual reports of any excursions under the approved compliance assurance monitoring plan in accordance with the schedule specified in the source's Title V permit.

## PART G STATEMENTS OF BASIS, SPECIFIC STATUTORY AUTHORITY AND PURPOSE

### I.A. Adopted June 5, 1980

**Rational and Justification for the Repeal and Repromulgation of Regulation Number 3 and Common Provisions Regulation as Related to Regulation Number 3**

On December 14, 1978, the Air Quality Control Commission revised Regulation Number 3 (concerning requirements for filing air pollution emission notices, obtaining emission permits, and payment of fees with respect to both) for the primary purpose of bringing Colorado's air pollutant emission permit program into conformity with the requirements of the Federal Clean Air Act Amendments of 1977 to the extent authorized by the then effective State statutory authority: "The Air Pollution Control Act of 1970, "C.R.S. 1973, 25-7-101 et seq. The regulation as revised in 1978 and which became effective January 30, 1972, was submitted to the U.S. Environmental Protection Agency as a revision to the state Implementation Plan ("SIP") pursuant to Subsection 129(c) of the Federal Clean Air Act Amendments of 1977.

Since that submittal, the Colorado General Assembly has repealed and reenacted the State's basic air pollution control statute: Article 7 of Title 25, Colorado Revised Statutes, 1973. The new article, known as the "Colorado Air Quality Control Act" (designated House Bill 1109 in the 1979 legislative session), became effective June 20, 1979, and largely brought the State statute into conformity with the Federal legislation, mandating the Commission to develop a comprehensive air pollution control program meeting the requirements of the Federal Clean Air Act.

Revisions also respond to the requirements set forth in the October 5, 1979 Federal Register notice which conditionally approved portions of the Colorado SIP and set forth certain requirements for securing their unconditional approval. E.G., see Section IV.D.2.a.(iv) of revised Regulation Number 3, which incorporates the requirements of Section l72(b)(II)(A) of the Clean Air Act. 44 Fed. Reg. 57401, 57408 (1979).

The Commission has made an effort to formulate a permit program meeting the requirement of and paralleling of the provisions EPA policies and rules to the extent authorized by House Bill 1109 and to the extent deemed appropriate by the Commission for Colorado's particular circumstances. This has been done in order to meet certain specific requirements expressly set forth in the Federal Clean Air Act, to meet certain specific requirements EPA has determined are required for compliance with the Federal Act, and to avoid subjecting sources of air pollution in Colorado to differing State and Federal requirements. The Commission considered the assurance of reasonable further progress toward attainment of National Ambient Air Quality Standards as the primary underlying criterion in developing permit requirements for sources located in or near nonattainment areas.

Consideration has also been given to the opinion of the United States Court of appeals for the District of Columbia in the case of Alabama Power Company v. Costle F.2d (D.C. Cir., 1979).

APENs

In order to reduce the administrative burden on both the Air Pollution Control Division (“the Division”) and owners and operators of air pollution sources, the filing of revised air pollution emission notices for the purpose of reporting significant changes in emissions will be required only on an annual basis, rather than whenever a significant change in emissions occurs. In making this revision, the Commission relied on the representations of the Division that annual reporting would be sufficient for purposes of keeping the emissions inventory current.

Street Sanding

With the exception of street sanding (and indirect sources), the exemptions provided in the revised regulation from the APEN-filing and emission permit requirements are for minor or insignificant sources of emissions.

Although not finding that particulate emissions resulting from the application and re-entrainment of “sand” applied to snow or ice covered roadways as a traffic safety measure are insignificant, the Commission has exempted sanding from the APEN-filing and permit requirements out of administrative necessity.

Little benefit can be obtained from the filing of APENs in light of the fact that the amount of emissions cannot be predicted with any reasonable accuracy due to varying factors such as weather. APENs would therefore serve little purpose as notices of expected emissions.

It is the judgment of the Commission that protection of persons and property by sanding snow and ice covered roadways is an overriding consideration and that the costs of not taking such safety measures would far outweigh any air quality benefits resulting from requiring permits for sanding. Sanding should not therefore be prohibited -- even without a permit. The only reason for imposing a permit requirement would be to facilitate enforcement of control measures to limit emissions, which the Commission believes may be accomplished without a permit requirement through emission control regulations and provisions in local elements of the State Implementation Plan.

Major Source, Major Modifications, and the "bubble" Concept

The Commission has retained requirements that new "major sources" locating in nonattainment areas and "major modifications" to existing sources in nonattainment areas meet special requirements (Offsets, LAER, etc.) designed to allow for continued development in such areas without interfering with reasonable further progress toward attainment of National Ambient Air Quality Standards. The criteria for determining when a new source or modification to an existing source is "major" however, have been extensively revised.

Prior to the U.S. Court of Appeals Decision in Alabama Power Company v. Costle, EPA had defined "potential to emit" -- a key phrase in the definition of "major emitting facility" -- in terms of uncontrolled emissions. The court however, interpreted the phrase "potential to emit" as used in the definition of "major emitting facility" in Section 169(1) of the Clean Air Act as taking "into account the anticipated functioning of the air pollution control equipment designed into the facility," thereby drastically reducing the number of sources qualifying as major. In response to this decision, on September 5, 1979, EPA proposed amendments to its regulations concerning requirements for SIPs including those pertaining to prevention of significant deterioration of air quality ("PSL)") and new source review in nonattainment areas, as well as EPA's Emission Offset Interpretative Ruling. 44 Fed. Reg. 51924 (1979). The Commission in reviewing Regulation Number 3 and the Common Provisions Regulation has incorporated many of the amendments adopted by EPA in its regulations including classifications of sources as major or minor based on controlled emissions.

The court in Alabama Power Company struck down the ~PA regulation definition of "major modification" which definition required the imposition of the special nonattainment area requirements (Offsets, LAER, etc.) on sources when modifications resulted in an increase in emissions of a criteria pollutants of 100 tons per year or more (for certain~ listed categories of sources; 250 tons or more for sources not listed). The court held that the special nonattainment requirements applied to all modifications of major emitting facilities except those resulting in only "de minimus" increases in emissions. The court stated, however, that it would be permissible to look at the net increase in potential emissions from a major source in determining whether Offsets, LAER, etc., will be required.

In its proposed rules, EPA has adopted the "net increase" or "bubble" approach which generally allows a major source undergoing modification to avoid permit review as a major modification by allowing emission reductions elsewhere at the source to offset any increases resulting from the proposed modification. The Commission has adopted the "bubble" concept and many of EPA's specific regulatory provisions with respect to the concept as applied to modifications.

The court in Alabama Power Company also held that fugitive emissions could be included in determining whether a source is "major" only to the extent, such emissions were expressly determined to be included by rule of the EPA administrator. In response, EPA has proposed a regulatory definition of "Potential to emit" by which fugitive emissions from twenty-seven (27) listed sources would be included in determinations of which new sources and modifications are major. 44 Fed. Reg. 51956, 51958 (1979). In recognition of the fact that such emissions would be included in determinations of whether a source or modification was major if they were emitted through a stack (as opposed to being "fugitive"), recognizing that generally emissions from the twenty-seven (27) listed source categories contribute to hazards to public health and welfare, and to be consistent with the federal scheme, the Commission has also decided to consider fugitive emissions from the twenty-seven source categories in major source/major modification determinations to the extent they are quantifiable. An owner or operator may avoid the inclusion of fugitive emissions of particulate matter by demonstrating that such emissions are of a size and substance, which do not adversely affect public health or welfare.

Banking

C.R.S. 1973, *25-7-304* requires the attainment program to provide that emission reduction offsets exceeding those required for the granting of a permit "may be preserved for sale or use in the future." Section V of Regulation Number 3 establishes an administrative framework and the basic requirements of such a procedure consistent with the "banking" provisions established by EPA in its Emission Offset interpretative Ruling, 44 Fed. Keg. 3274, 3280, 3285 (January 16, 1979) (to be codified as Appendix S to 40 C.R.S. Part 51).

Extended "Debugging" Period.

Pursuant to C.R.S. 1973, 25-7-1 14(4)(j), the Division may grant the owner or operator of a new source up to six months after commencement of operation in which to demonstrate compliance with all terms and conditions of its emission permit. The Commission determined, however, that under certain circumstances it would be appropriate to allow a source employing innovative control technology additional time in which to bring the operation of the source into full compliance. Therefore, pursuant to its authority under C.R.S. 1973, 25-7-109(5), the Commission has provided in paragraph IV. H.6. of Regulation Number 3 for such temporary relief from controls under specified limited circumstances. The provision is intended for very limited application.

PSD

Regulation Number 3 does not address the subject of special permits for major sources locating in attainment areas to insure prevention of significant deterioration of air quality. The Commission decided to wait until EPA's PSD regulations to establish a fully State-operated program. State emission permits are nonetheless still required for sources locating in attainment areas.

Common Provisions Regulation

In connection with the revision of Regulation Number 3, the Commission concurrently made limited, related revisions in its Common Provisions Regulation. Sections I.B. and I.C. of that regulation have been changed to reflect the renumbering of the Sections in the State statute authorizing the Commission to promulgate regulations and to reflect the amended language in the declaration of legislative intent.

Section I.F. of the regulation was amended to add new abbreviations used in revised Regulation Number 3 and Section I.G. (definitions) was amended to delete, revise, and add terms and their definitions to reflect changes in the terminology used in Regulation Number 3.

**I.B. Adopted May 13, 1982**

**Concerning May 13, 1982 Amendment to Section IV.C. (Public Comment) for Small Sources Locating in Nonattainment Areas**

The rationale for this proposed revision is based on the underlying purpose of public comment: to obtain public input on proposed sources that the Air Pollution Control Division (APCD) can use in considering whether a permit should be granted.

Under the previous regulation all sources locating in nonattainment areas were subject to the public comment requirement unless the APCD exercised its discretion under Section IV.C.3. (sources of less than 6 month's duration) to exempt them. APCD experience has shown that there are four categories of small sources that frequently locate in nonattainment areas, but which did not stimulate comment from the public. These categories are: (I) service stations; (2) restaurants; (3) land development (houses and commercial); and (4) other small sources (such as concrete batch plants). Basically, all the effort put into preparation of public comment packages for these sources can now be used more efficiently and the associated expense to industry saved.

The limit of 5 Tons Per Year (tpy) of controlled annual emissions is based on calculations that show most of the sources in these four categories emit less than 5 tpy of any one pollutant. Service stations, for example, generally emit I to 2 tpy. In many cases less than I tpy is emitted.

Under the revised regulation, sources less than 5 tpy can still be subject to public comment if the Division determines it appropriate based on criteria set forth in the regulation. The difference is that the APCD would have discretion to decide instead of being required to provide public notice. Controversial sources such as gravel pits, odor sources and landfill operations are subjected to public comment by the APCD regardless of the level of emissions. This practice will continue in effect.

**I.C. Adopted March 10, 1983**

**Prevention of Significant Deterioration Program Regulations in Regulation Number 3**

This Statement of oasis and Purpose for the Prevention of Significant Deterioration (PSD) Program Regulations complies with the State Administrative Procedure Act, CR5 1973, 24-4-103(4). The statutory authority for the PSD regulations are in the Air Quality Control Act at CR5 973, 25-7-102, 25-7-105, 25-7-106, 25-7-108, 25-7-109, 25-7-114, 25-7-116, 25-7-201 et seq. The general purpose of these regulations is to prevent the significant deterioration of air quality in those Sections of the state, which has attained the national ambient air quality standards. The parties to this rulemaking include:

> Colorado Association of Commerce and Industry; Rocky Mountain Oil & Gas Association, Inc.; Chevron Shale Oil Company; Union Oil Company of California; Colorado Ute Electric Association, Inc.; The Colorado Mountain Club; COAL; Public Service Company of Colorado; City of Colorado Springs; CF&I Steel; Environmental Defense Fund, Inc.; United States Department of the Interior; and United States Department of Agriculture.

The Air Pollution Control Division acted as staff for and advised the Commission during the proceeding. See CRS 1973, 25-7-lll(2)(g).

The PSD regulations adopted by the Commission are in many respects identical to the U.S. Environmental Protection Agency (EPA) PSD regulations. See 40 CFR 51.24 et seq.; 40 CFR 52.21 et seq. The primary reason for this is that the State Act requires that the S~PSD program be in accordance with the federal Clean Air Act PSD provisions. See CRS 1973, 25-7-203. Thus, federal PSD requirements are generally a minimum for the State PSD Program. For these reasons, to the extent that the federal PSD rules are identical or substantially identical to the state regulations, the Commission incorporates herein the EPA statements of basis and purpose for the federal PSD rules at 43 Fed. Reg. 26380 et seq. (June 19, 1978) and 45 Fed. Reg. 52676 et seq. (August 7, 1980).

The Commission has additional authorities to prevent significant deterioration of air quality. In several important areas the Commission has tailored these regulations to meet the concerns of Colorado citizens. These areas include the requirement for an impact analysis on water to determine acid deposition effects, the authority to make independent determinations on adverse impact to visibility in Class I areas if the federal land manager fails to fulfill his responsibility to do so, the requirement to establish baselines for, and to monitor air quality related values in, Class I areas to determine the effects of emissions on such values, and the application of Class I sulfur dioxide increments to several Class II primitive areas and national monuments.

The proposed PSD regulations included several provisions reflecting the terms of a settlement agreement in the matter of Chemical Manufacturer's Association, et al. V. EPA in which EPA has agreed to propose amendments to its P50 rules. The Commission has rejected the adoption of such provisions for several reasons. They are arguably less stringent than current EPA rules in that they would appear to permit more air pollution. Because they may be less stringent, their adoption appeared likely on the basis of EPA testimony to impede the approval of the state PSD program by EPA at this time. Finally, EPA's schedule for consideration of such provisions is unknown. Subsequent to EPA action on the provisions of the settlement agreement, the Commission will reconsider those provisions.

The PSD regulations will generally not become applicable to major sources or major modifications in Colorado - until EPA has approved them. See CRS 1973, 25-7-210. However, the regulations pertaining to attainment area designations and the enforcement of Class I sulfur dioxide increments in those areas-listed in CRS 1973, 25-7-209 will be applicable upon the effective date of these regulations. These regulations will be effective twenty (20) days from publication in the Colorado Register.

DEFINITION OF “ACTUAL EMISSIONS”

The definition adopted is essentially identical to the EPA definition.

One party proposed that reference should be made to consideration of control efficiency. The Commission did not adopt this proposal because the definition inferentially considers control equipment efficiency and the reference requested would create confusion, when actual test data were available, as to whether a separate “efficiency” factor was to be applied.

Another party, in commenting on the definition of “baseline concentration,” expressed concern that the determination of “actual emissions” could take place, for example, during a low-demand period for a power plant. Such determination would result in an emission rate considerably less than the full-capacity allowable emission rate, resulting in a low baseline concentration. The power plant, operating the next year at full capacity, could consume all or most of the available increment, prohibiting growth in the area. The Commission recognizes that, for certain sources such as power plants (i.e., fossil fuel-fired steam generators), the source must respond to constantly changing demands with significant changes in emissions from year to year. Therefore, for fossil fuel-fired steam generators, “allowable emissions” should generally be considered “representative of normal unit operation” rather than actual emissions in determinations of “actual emissions” for determining baseline concentration and increment consumption, unless it is clearly demonstrated that a lower level of emissions will never be exceeded.

DEFINITION OF “BASELINE AREA” AND “BASELINE DATE”

“Baseline area” is not specifically defined in the State Act but is simply referred to as “an area subject to this article~~ in the definition of baseline concentration. CRS 1973, 25-7-202. The Federal Clean Air Act definition of “baseline concentration,” Section 169(4), is identical to the state's, and EPA has interpreted” an area subject to this article” to mean the attainment and unclassifiable areas designated pursuant to Section 107(d)(l)(D) or (E) of the Federal Clean Air Act. Such an interpretation is also reasonable under the Colorado Air Quality Control Act which states that the Commission shall adopt measures “to prevent significant deterioration of ambient air quality in each region, or portion thereof, of the state identified pursuant to Section 107(d)(1)(D) or (E) of the Federal Act.” The result of EPA's definition is that the entire state is the baseline area for 502, and air quality control regions for particulate matter.

Several parties proposed alternative approaches to the definition of baseline area. These approaches ranged from a modeled 1-$\mu g/m^3$ impact area (based on 7.5 minute quadrangles, the county-township-range-Section system, or a metric grid) to the entire state.

The Commission adopted the EPA definition for the following reasons:

(1) The EPA approach has been in effect for several years and has proven workable. EPA has wel1-developed procedures for performing source impact analyses in large baseline areas, which the state can use. Changing the definition of baseline area would result in use of an approach that has not been proven and that would cause a discontinuity for the regulated industries when the PSD program is delegated to the state.

(2) The use of areas larger than the source impact area means that baseline concentrations will be determined at an earlier date, and increments will be consumed from an earlier date, thus minimizing air quality deterioration. This fulfills the primary purpose of the State Act. See CRS 1973, 25-7-102.

Certain parties were concerned that baseline areas larger than the impact area might unnecessarily inhibit economic growth in the unaffected portion of the baseline area, but should that occur, and there are no specific examples in the record of where that would occur, the Commission could consider subdividing baseline areas to allow for a new baseline date and concentration.

Testimony from Pitkin County and members of the general public indicated concern that with small baseline areas, minor source emission increases would continue to raise the background ambient air concentrations, especially for particulate matter, before a major source would locate in an area to begin the counting of increment consumption. The baseline areas selected by the Commission for particulate matter represent a balance between a recognition that particulate matter emissions are often a more localized problem than are gaseous emissions (hence the use of AQCRs for particulate matter instead of the entire state, as is the approach for S02) and the need to begin counting increment consumption expeditiously (hence, the use of AQCRs for particulate matter rather than the smaller impact area). Only two AQCRs in Colorado have been triggered during the six years PSD has been in effect. Since triggered baseline areas can in the future be subdivided into triggered and untriggered areas, the Commission considers the use of baseline areas the size of AQCRs sufficiently flexible for purposes of reasonable application, economic growth, and prevention of air quality deterioration.

(3) Use of a baseline area equivalent to the 1 ug/$m^3$ impact area could result in a situation where impacts on a Class I area individually were each less than 1 ug/$m^3$ , with the result that the Class I area would not be a part of a baseline area. Yet the cumulative impact of these sources could be greater than the 1 ug/$m^3$ increment for particulate matter 'for Class I areas, so that deterioration of air quality greater than that allowed by the regulation could legally occur.

(4) The use of the entire state as an $SO_2$ baseline area provides maximum protection for all Class I areas in the state. This is of particular concern to the Commission, since the general flow of air from west to east and the long-range transport of gaseous pollutants can result in effects on nearly all of Colorado's Class I areas by $SO_2$ sources on the West Slope. The effects and extent of acid deposition, to which $SO_2$ is a major contributor, was a topic of extensive testimony at the hearings; the definition of the entire state as a baseline area for affords maximum protection of the environment while the problem of acid deposition receives additional study.

DEFINITION OF “BASELINE CONCENTRATION”

Two parties proposed changes to this definition, both suggesting the substitution of “allowable” for “actual” emissions in portions of the definition. The concern regarding power plant actual versus allowable emissions is discussed under “Actual Emissions,” above.

The other concern arises from the possibility of a large difference between actual and allowable emissions in the calculation of increment consumption or in establishing baseline concentrations. This is discussed extensively in the EPA preamble to the August 7, 1980 PSD regulations (Division Exhibit B, pp. 74-76) concerning increment consumption. EPA's rationale is that actual emissions more reasonably represent actual air quality than allowable emissions and that because actual emissions are based on at least two years of operation, future emissions could be reasonably expected to remain at the same level. EPA therefore uses actual emissions to avoid “paper consumption” of increment (or modeled baseline concentrations which would exceed monitored levels) The Commission concurs with the EPA rationale and has adopted the EPA approach of using actual emissions to track increment consumption and determine baseline concentrations.

DEFINITION OF “COMPLETE”

The Environmental Defense Fund (EDF) proposed a list of specific elements of a PSD permit application, for aid in determining whether an application is “complete,” which was generally incorporated in the final rule. The proposed list of items would add some certainty and clarification for the applicant and the Division of the specific items required demonstrating completeness of an application. Regarding items (i) and (iii)-(iv)., opposition to the list by several parties was primarily that it was redundant with other requirements of the rules. York, Nov. 10 Tr. at 18 et seq. and 60 et seq. .Item (ii) was retained because, for many or most applications, such information would be necessary to verify the applicant's modeling.

DEFINITION OF “NET EMISSIONS INCREASE”

Several parties proposed crediting increases or decreases in emissions, which occur up to five years after a modification, becomes operational. The Commission did not adopt this recommendation because EPA specifically prohibits states from crediting decreases, which would occur after the change occurs. 40 CFR 5l.24(b)(3). In addition, it would prove difficult to exact an enforceable agreement for a source to close down or otherwise decrease emissions at some future date.

Several parties proposed in paragraph f(ii) to shift “enforceable” from time of construction to time of operation. This change would not be consistent with the state statutory requirements, which prohibit construction or operation of a non-permitted new source or modification. The suggested change would also needlessly complicate the correlation of permits to enforceable decreases in emissions.

In response to a party comment that 90 days to report a reduction in emissions is too short, the Commission agreed and has allowed such reports to be made within a year of the decrease unless an extension is granted. A longer time would make the reduction difficult to verify.

DEFINITION OF “SECONDARY EMISSIONS”

The final definition incorporates a recent amendment by EPA, 47 Fed. Reg. 27554 (June 25, 1982) and is consistent with CRS 1973, 25-7-202(6.5).

DEFINITION OF “ALLOWABLE EMISSIONS”

In several Sections of EPA's PSD rules, including its definition of “allowable emissions,” EPA grants credit for permit conditions only if they are “federally enforceable. In each of such Sections, the Commission has deleted the qualification of “federally” and has in the Common Provisions Regulation defined “enforceable” so that it is consistent with 'S definition of 'federally enforceable.”

DEFINITION OF “SIGNIFICANT”

Several parties commented that the proposed definition, which defined both “significant” and “significantly” and included a listing of “significant concentrations,” was confusing and unnecessary. The proposed definition also gave the Division the discretion to (1) determine that certain sources were not significant even if the source met the definition, and (2) to determine significance levels for non-listed pollutants. In addition, it limited the definition for sources affecting Class I areas to those sources producing a “significant” impact. There were several Sections in the proposed regulations that used the “significant” definition of ambient concentrations to allow impacts to Class I areas not allowed under EPA rules. EPA and the National Park Service commented that these changes resulted in a less stringent definition. The Commission agreed with these comments. The final definition is essentially identical to EPA's and uses only emission rates to define “significant,” and the use of “significant” to qualify impacts to Class I areas in other Sections of the rules has been deleted.

DEFINITION OF “MODIFICATION”

One party proposed that an existing exception for increases in ~ emissions caused by adding new emission control equipment (e.g., replacing scrubbers with fabric filters) be retained. The Commission acknowledges that this exemption was intended to avoid penalizing a source willing to improve particulate matter collection by converting from scrubbers to baghouses or electrostatic precipitators. Since scrubbers collect gaseous pollutants, but baghouses and precipitators do not, the amount of $SO_2$ emitted would increase, hence the exemption. Since there are a number of nonattainment areas for particulate matter, but none for $SO_2$, the Commission will continue to encourage additional control of particulate matter by including this exemption in the definition of “modification.”

It should, however, be noted that this exemption is not included in the definition of “major modification,” so a significant increase in SO2 emissions from a major source will result in P50 applicability. The effect of this is to provide the exemption only for minor sources and minor modifications.

DEFINITION OF “STATIONARY SOURCE”

The proposed definition was revised to include language essentially identical to that of EPA at 40 CFR 51.24(b)(5) and (b)(6). The final rule allows more discretion to define stationary source on a case-by-case basis. The definition clarifies that a source in a nonattainment area may also be “an identifiable piece of process equipment” which makes it consistent with a recent federal case. See Natural Resources Defense Council et al. V. Gorsuch, et al., 685 F.2d 718 (D.C. Cir. 1982).

DEFINITION OF “FUGITIVE DUST”

The State Act exempts “fugitive dust” from regulation under the PSD program, including exemption from determinations of whether a source or modification is major and of increment consumption. C.R.S. 1973, 25-7-202(4), -202(5),-204(l)(b), and -204(2)(c). “Fugitive Dust” is defined as:

> Soil or other airborne particulate matter (excluding particulates produced directly during combustion) resulting from natural forces or from surface use or disturbance, including, but not limited to, all dust from wind erosion of exposed surfaces or storage piles and from agriculture, construction, forestry, unpaved roads, mining, exploration, or similar activities in which earth is either moved, stored, transported, or redistributed; except that fugitive dust shall not include any fraction of such soil or other airborne particulate matter which is of a size or substance to adversely affect public health or welfare.

C.R.S. 1973, 25-7-202(3). Under such definition, fugitive particulates are regulated in the PSD program if they are “of a size or substance to adversely affect public health or welfare.”

The exemption of “fugitive dust” is an issue because EPA counts total suspended particulates (“TSP”) in determining increment consumption, maintenance of primary and secondary NMQS, and source applicability. Therefore, to the extent that the state excludes some sizes of particulate matter in these determinations, its regulations are arguably less stringent than EPA's, although as explained below, because of depositional effects, there is generally an insignificant difference between the counting of TSP and the counting of smaller particulates.

The basis for setting the primary NAAQS is health effects; the basis for setting the secondary NAAQS is welfare effects. These are. also the bases under the State Act for counting fugitive particulates in the PSD program. Because the bases for the State's inclusion of fugitive particulates and for EPA'S promulgation of particulate matter NAAQS are essentially identical, it is appropriate to consider whether the NAAQS should be the standard for determining which particulates are “of a size or substance to adversely affect public health or welfare.” However, EPA's current primary and secondary NAAQS for particulates are based on the “Air Quality Criteria for Particulate Matter” (1969), Div. Ex. R., which has generally been superseded by more recent research and analysis. For that reason, EPA in the CMA v. EPA Settlement Agreement has agreed in the near future to promulgate new primary, and perhaps secondary, NAAQS for particulates which would exclude particulates above a size posing no health or welfare risks.

EPA's staff review, in anticipation of revisions to the particulate matter definition and NAAQS, of the effects of particulate matter on health concludes that the size counted should be less than 10 urn, which includes those particles capable of penetrating the thoracic regions. “Review of the National Ambient Air Quality Standards for Particulate Matter: Assessment of Scientific and Technical Information,” EPA 450/5-82-001 (January 1982).

EPA staff review of welfare impacts indicates that visibility impacts are generally caused by fine particulates of less than 2.5 um. Id. at 122. However, such review recognizes that “the full size range of particles including dustfall can contribute to soiling, become a nuisance and result in increased cost and decreased enjoyment of the environment.” Id. At 140. Further, the EPA “staff recommends consideration of the economic and other effects associated with soiling and nuisance when determining whether a secondary standard for TP or for TSP or other large particle indicator is desirable,” id. at 141, and that “the basis for selecting a particular level for a secondary TP or TSP standard is a matter of judgment.” (emphasis added) Id. at 147. The EPA staff review indicates that EPA will probably propose fine particulate secondary standard but is undecided as to whether to establish a TSP or large particulate secondary standard, and that there is a basis for concluding that welfare impacts are being caused by all sizes of particulates. Additionally, there was public and party testimony on welfare effects from fugitive particulates, some of which can be assumed to be large particles. See Markey, November 10 Tr. at 2 et seq.

One of the apparent concerns of parties and persons opposing the use by the Commission of TSP as a welfare standard is that the increment would be consumed and that no further development could occur. Division Exhibit W, which compares the modeled ambient impacts of TSP using a deposition model with particulates of 10 urn or less using the same model, shows that the larger particles deposit quickly and that the ambient impact is relatively the same at a distance of 1000 meters or greater. The implication of this is that for many sources the modeling of increment consumption would have the same general results whether TSP is counted or whether only particles 10 urn or less are counted (assuming the boundary of the source is 1000 meters or farther from the emissions point). Another implication is that welfare impacts from large particulates can only result within relatively short distances of a source.

Another concern was that the legislative intent was not to count TSP, although there was not clear evidence of legislative intent presented to the Commission. In any event, statutory language leaves the determination to the Commission to decide what particulates are of a size or substance to adversely affect health or welfare.

Given the foregoing considerations and the Commission's general interest in interpreting health and welfare effects of particulates consistent with EPA, but also given the uncertainty surrounding the revision of the particulate NAAQS by EPA, the Commission determines that in applying the definition of “fugitive dust”, the adverse effects on health or welfare of fugitive particulate emissions should be determined individually for each source. Adverse welfare effects of nuisance and soiling will be presumed to occur if the source would have offsite, ambient, particulate impacts unless the permit applicant rebuts such presumption with clear and convincing evidence. The result of this presumption will be that in most cases, large particulates will be counted and there will be no difference between EPA s treatment of particulates and the states. Other health and welfare effects shall generally be evaluated based on EPA's most recent research and analysis, but the permit applicant shall have the burden of proof of demonstrating with clear and convincing evidence, which, if any, sizes or substances of fugitive particulates do not adversely affect, health or welfare. This presumption of health and. welfare effects has been incorporated in the definitions of “major stationary source” and “major modification,” Section XI.A.4 on Exclusions from Increment Consumption, and Section V.D.3.c.(i)(B).

Upon EPA's adoption of revised NAAQS for particulates, the Commission may consider whether to revise this Statement of Basis and Purpose or the definition of “fugitive dust” to reflect such revisions., Should EPA decide not to have a secondary NAAQS incorporating nuisance and soiling (welfare) impacts of large particulates, the Commission will consider whether the welfare effects of large particulates are significant enough to be included, or whether they are relatively insignificant and, thus, should not be counted in the state PSD Program.

DEFINITION OF “MAJOR SOURCE” AND “MAJOR MODIFICATION”

The State Act permits the counting of fugitive emissions in determining whether a source or modification is major “only if the Commission adopts regulations to include fugitive emissions for that source category.” CR5 1973, 25-7-202(4) and (5). The Federal Clean Air Act has a similar requirement at Sec. 302(j). EPA has interpreted the rulemaking requirement to mean simply a consideration in rulemaking of whether fugitive emissions should be counted and a requirement that affected industries be allowed to present policy or factual reasons why fugitive emissions should not be counted. 45 Fed. Reg. 52676 (August 7, 1980). Based on this rationale, EPA's rules currently list 26 categories of sources for which fugitive emissions are counted. A similar interpretation of the State Act is reasonable and has been adopted by the Commission.

One party recommended the addition of uranium mills and coal mines to the list of sources for which fugitive emissions would be counted. However, those sources could not be considered in this proceeding due to inadequate public notice. The Commission intends to consider those sources for listing as soon as practicable.

In the CMA v. EPA Settlement Agreement, the EPA has agreed to remove these 26 listed sources on the basis of industry's argument that the rulemaking requirement means that EPA must identify reasonable methods for measuring and modeling fugitive emissions from a category of sources. Although not agreeing that this is legally required under state or Federal law, the Commission has determined that Division Exhibit F, primarily, makes that demonstration for the ten categories located or expected to locate in Colorado.

It should be noted that measurement methods are not only available, but have been in use for a number of years and have provided test results that are the basis for the fugitive emission factors used by EPA and other control agencies, including the Colorado Air Pollution Control Division.

The following important parallels between stack emission 'factors and fugitive emission factors support the conclusion that fugitive emission factors are relatively as reliable and as reasonably available as stack emission factors:

- Both are based on numerous test data at different locations on different equipment or operations.

- Both are influenced by many variables (e.g., for a stack, flow rate, temperature, process variations; for a fugitive plume, wind speed, moisture content of the material, size distribution of the material).

- Neither is intended to represent actual emissions from a specific source. Actual acceptable test data for a specific or similar source would always be used in lieu of an emission factor.

- Both are intended as air management tools to allow pre-construction assessment of a source impact or as a representative value to average total emissions from a number of similar sources (e.g., all waste incinerators, commercial boilers, or coal storage piles) for such air quality management purposes as determining “reasonable further progress” in nonattainment areas.

Stack and fugitive emission factors are both estimates; such factors are nevertheless widely used by control agencies and applicants alike. However, control agencies generally have no objection to, and would prefer, actual test data in lieu of factors whenever such information is submitted. (See Testimony of McCutchen, October 28, 1982; Egley, November 18, 1982, pp. 72-75 and p. 99; Bertolin, October 29, (am), p.39.)

One party's concern involved whether the emission factors for a facility can be extrapolated to a larger facility, specifically, from a 7000 ton per day oil shale processing facility to a 50,000 ton per day facility. Scale-up is a widely used and accepted approach throughout industry for estimating the feasibility of larger-scale facilities from results at smaller-scale facilities. There are a number of well-known precautions that should always be considered when extrapolating, and a control agency should be at least as cautious in extrapolating emission levels as the applicant is in extrapolating process data. Of course, if different equipment, such as a retort, is to be used at a proposed facility, an emission estimate would be based on mining and handling practices and on different processing equipment emission factors (e.g., refinery emission factors) which are similar to oil shale processing activities where such would be more accurate than extrapolation. Therefore, either through extrapolation or through the application of other more applicable and available emissions factors, relatively accurate emissions levels from all types of oil shale facilities can be calculated.

The same modeling techniques used to model stack emissions can be and are used to model fugitive emissions (Division Appendix F). One modeling parameter, deposition, is more critical in modeling fugitive particulate emissions and should be carefully evaluated. Fugitive particulate emissions usually contain more large particles than do controlled stack emissions. These large particles generally settle out rapidly, so that the impact at a plant boundary is usually much less than would be anticipated by the quantity of emissions at the source. See “Fugitive Dust.” However, acceptable models exist which incorporate deposition and thereby provide a reasonably accurate assessment of fugitive particulate emission impact. Models without deposition can be used for gaseous and fine particulate fugitive emissions. Models have recognized limitations, but they are as accurate for fugitive emissions as for stack emissions.

The following information, which is primarily from Division Exhibit F, concerns the major policy and factual reasons for counting fugitive emissions from each of ten source categories:

Coal Cleaning. A typical plant would process 10,000 tons per year (tpy) of coal and emit approximately 280 tpy of particulate matter, 96% of which would be fugitive emissions. Over 100 tpy of the fugitive emissions are less than 15 microns in diameter and are considered inhalable particulate (IP).

Portland Cement. The typical plant produces 500,000 tpy of cement and emits approximately 370 tpy of particulate matter, 60% of which would be fugitive emissions.

Iron & Steel Mills (Including Coke Ovens). A typical plant would produce several million tons of steel per year and emit approximately 3,600 tpy of particulate matter, 64% of which would be fugitive emissions.

The coke plant would produce over half a million tons of coke per year and emit approximately 700 tpy of particulate matter, 10% of which would be fugitive emissions, and 1,500 tpy of uncontrolled fugitive hydrocarbon emissions.

Petroleum Refineries. A typical plant would process 25,000 barrels of oil per day and emit approximately 1,100 tpy of hydrocarbons, 57% of which would be fugitive emissions.

Lime Plants. A typical plant would produce 300,000 tpy of lime and emit approximately 1,800 tpy of particulate matter, 33% of which would be fugitive emissions.

Fuel Conversion. A typical shale oil plant would produce 50,000 barrels per day of oil and emit 4,800 tpy of particulate matter, 12% (500 tpy) of which would be fugitive emissions, and 8,611 tpy of hydrocarbons, 12% (1,080 tpy) of which would be fugitive emissions.

Sintering Plants. A typical plant would emit approximately 400 tpy of particulate matter, 20% (80 tpy) of which would be fugitive emissions.

Power Plants and Boilers. A typical, but well-controlled, new 500 MW power plant burns 2.1 million tpy of coal and emits approximately 620 tpy of particulate matter, 18% (110 tpy) of which would be fugitive emissions. These fugitive emissions are from coal handling and storage, among the most visible and complaint-related of all fugitive emission sources.

Petroleum Transfer and Storage. A typical plant has a capacity of 476,000 barrels and an annual throughput of 7,123,000 barrels per year and emits 267 tpy of hydrocarbons, 72% of which are fugitive emissions.

In conclusion, the Commission has determined that fugitive emissions from the above sources should be included in determining whether the source or modification is major for the following general reasons:

(a) Fugitive emissions consist of the same pollutants that are emitted through stacks and regulated as stack emissions;

(b) The quantity of fugitive emissions, both in absolute and in relative terms, is significant; and

(c) Although this finding is not legally required, there are methods reasonably available for measuring and modeling fugitive emissions.

PUBLIC COMMENT AND HEARING REQUIREMENTS

The Commission has adopted a regulation designed to offer maximum opportunity for any interested person to learn about, and become involved in, the PSD permit review process. Adopted in the final rule are proposals by one party that (a) the public notice be printed not only in a newspaper of local distribution, but also in one of state-wide distribution to increase the number of potential interested persons reached by the notice, (b) that the public hearing be held at least 60 days after the Federal Land Manager (FLM) has received the notice and permit application, to allow the FLM adequate response time, and (c) that any interested person receive notice of public hearing. In addition, the Commission agrees with the Division proposal to implement and maintain an “interested party” mailing list as described in Division Exhibit M.

The proposed rule contained a requirement that the Division notify the county Commissioners in affected counties when a proposed source would consume 50 percent or more of the remaining PSD increment. Two parties proposed that this requirement be deleted as allowing local land use decision-makers to unduly influence air permit decisions. The intent of this requirement, which has been modified to notify county Commissioners of any PSO permit applications, is not to provide opportunity for counties to comment to the Division on land use; rather, it is to provide information to the counties on proposed sources so that the counties can more adequately assess their priorities and needs. PSD permit approval or denial is to be based solely on the criteria specified in this regulation; land use decisions are, and will remain, the responsibility of local governments.

Regarding the issue of land use decisions, one party commented that Section IV.C.4.e.(iii) of this final rule, which solicits comments from interested parties on alternatives to a proposed PSD source or modification, constitutes the inclusion of land use factors in permit approval determinations. The Commission did not remove this Section because it is required by the State Act, CRS 1973, 25-7-l14(4)(f)(I)(B). Furthermore, the intent of soliciting such alternatives is for the assessment of alternatives with respect to control technology and source impact, not land use.

CONTROL TECHNOLOGY REVIEW

One party proposed that the last sentence in Section IV.D.3.a.(i)(C), which requires the owner or operator of a phased project to demonstrate the adequacy of a previous best available control technology (BACT) determination, be deleted. The Commission did not delete this sentence because (1) an EPA regulation requires such a condition and deletion of this requirement could be considered less stringent, and (2) the requirement is intended to provide for the possibility of a different BACT determination if new technology has developed between the time of permit review and the next phase of a project for which construction has not yet commenced, a time period which can easily exceed five years on large projects.

POST-CONSTRUCTION MONITORING

Five parties proposed that post-construction monitoring requirements be limited to a maximum of one year. The Commission recognizes the concern of lessening the burdens on owners or operators, particularly if the information being gathered is unnecessary. But in many cases, there can be a very real need for monitoring for periods of time greater than a year to obtain reliable data. Accordingly, the final rule requires post-construction ambient monitoring for a period up to one year; additional ambient monitoring can be required only if it is necessary to determine the effect of emissions from the source on air quality. This necessitates an evaluation by the Division regarding the adequacy of the data, and a showing by the Division that additional monitoring is needed, before more than a year of monitoring could be required.

OPERATION OF MONITORING STATIONS

Three parties proposed that the rule be written to allow the latest changes in EPA-approved methods to be used without first having to amend the rule. The Commission agrees with the need to use the most up-to-date approved methods. Accordingly, the final rule specifies that “EPA accepted procedures...as approved by the Division” can be used.

ADDITIONAL IMPACT ANALYSIS

Section IV.D.3.a.(vi) of the final rule requires an owner or operator of a proposed PSD source to provide an analysis of the impairment to water that would occur as a result of emissions associated with the source.

This analysis is not required by the EPA rules. The Inclusion of water in the additional impact analysis reflects a strong concern by the Commission based in the record regarding acid deposition. At this time there is neither the information nor the evidence of damage to justify regulating acid deposition in Colorado. However, the vulnerability of high altitude lakes to acid deposition and the potential increases in acid-forming pollutants such as SO2 and NOx on the Western Slope from sources subject to the PSD program, particularly oil shale processing and large power plants, clearly demonstrate a need for a program to gather data, track and analyze this potential environmental problem. The inclusion of water in the additional impact analysis is intended to gather information on the problem; this analysis is not intended to affect permit approval or denial or control technology review decisions except for determinations of adverse impact to AQRVs in Class I areas. The issues, which have been raised concerning water impact analysis, are discussed in detail below.

a. Legal Authority to Require an Impact Analysis of Acid Deposition

The State Air Quality Control Act requires a PSD permit hearing to consider "air quality impacts of the source... and other appropriate considerations." C.R.S. 1973, 25-7-114(4)(f). Acid deposition can be construed as an indirect but potentially significant air quality impact which should be analyzed, especially in light of one of the stated purposes of the PSD Program "to protect public health and welfare from any actual or potential adverse effect which....may reasonably be anticipated to occur from air pollution or from exposures to pollutants in other media, which pollutants originate as emissions to the ambient air (emphasis added). Section 160(1) of the Clean Air Act. Acid deposition in water is those pollutants in other media originating as emissions to the ambient air.

The Federal Land Manager (FLM) of a Class 1 area is responsible for determining whether a source has an adverse impact on air quality related values which is generally defined as follows:

Any value of an area, which may be affected by a change in air quality. Examples include flora, fauna, soil, water, visibility, culture, and odors. Forest Service Comments, October 7, 1982, p.1.

Acid deposition may adversely affect such values, and thus an analysis of its effects should be required for review by the federal land managers of affected Class I areas.

b. Major Issues

The major issues discussed during the hearings are summarized below:

1. Are Colorado's watersheds sensitive to acid deposition?

John Turk of the USGS is involved in acid deposition research in Colorado and stated that 370 lakes in the Flattops Wilderness area comprising 157 hectares would be sensitive to potentially harmful degrees of acidification if precipitation attains an average pH of 4.0. (Exhibit 3, Nov. 10 Tr. at 153)

Ben Parkhurst maintains that there is talk of Colorado's lakes being sensitive (Oct. 29 Tr. at 146), but states that sensitivity must be considered together with acid inputs. Thus, if acid input to the water system is not sufficiently large the sensitivity question is not important.

Dr. William Lewis stated that Colorado's lakes are sensitive to acid deposition as demonstrated by the measured loss in buffering capacity he found in his studies. (Nov. 18 Tr. at 136-138)

In conclusion it can be inferred that some Colorado lakes are poorly buffered and if sufficient levels of acidity are introduced into the lakes, these poorly buffered "sensitive" lakes could develop acidification problems.

2. Has acidification occurred in any Colorado lakes?

John Turk of the USGS states that there has not been any large degree of acidification taking place in the lakes or streams he has studied in the Flattops. (Nov. 10 Tr. at 172)

Ben Parkhurst also states that there is no evidence to show that any acidification has taken place in Colorado Lakes. (Oct. 29 Tr. at 144 and 150-152)

Dr. William Lewis states that he has noted pH changes in lakes he has studied (Nov. 18 Tr. at 140), but he does not consider that to be the major point in regard to the acidification question. Lewis considers the loss of buffering capacity to be the best indicator of acidification effects on lakes and he has found statistically valid evidence to show that this has occurred. (Nov. 18 Tr. At 13 6-138)

In summary, there is some evidence that pH has dropped slightly in some of the lakes Lewis has studied, however, it does not appear that acidification (drop in pH) has occurred to any large degree in Colorado, however, in the prediction of future impacts, buffering capacity should be examined and this has dropped in the lakes examined by Lewis.

3. Is there a potential for acidification in the future?

Paul Ferraro has done some research on estimating potential acid deposition impacts on Colorado and has determined that under different energy development scenarios, there is a potential for acidification in sensitive lakes. (Nov. 10 Tr. at 158-159)

Parkhurst states that he would not expect acidification to be a problem in the future, unless the acid deposition reaches levels similar to those found in the Northeast. (Oct. 29 Tr. at 154-156) Parkhurst states that Ferraro's study is conservative and a pH drop to 5.8 would not affect fish.

Oppenheimer (EDF Exhibit 32 p. 6) states that if a 1-$\mu g/m^3$ increase in $SO_2$ (annual average) occurs, acid deposition levels could result which would be damaging to sensitive lakes.

In summary, it can be inferred that there is a potential for energy development activities to cause increased levels of acids to be deposited in the watershed, and effects on pH may occur depending on the buffering capacity of the water. The degree of the effect will depend on the amount of acid, thus the amount of emissions.

4. Are there adequate methods of modeling for acid deposition effects on watersheds?

Paul Ferraro has utilized what he refers to as a "first cut" approach in estimating impacts due to acid deposition. The approach utilizes methods employed by John Turk for determining sensitivity of waters and methods for estimating deposition rates developed by Systems Applications, Inc. (Nov. 10 Tr. at 154-176)

Oppenheimer (EDF Exhibit 32 p. 12-13) states that acid deposition modeling could be conducted using presently available plume models (approved by EPA), which incorporate a plume depletion function to account for deposition. Results from this model could then be compared to deposition standards.

In summary, there appear to be only screening techniques available at this time for estimating the impacts of acid deposition.

5. What level of acidification is dangerous to aquatic ecosystems?

Parkhurst stated that fish could survive in pH's as low as 4.1. (Oct. 29 Tr. 143)

Lewis states that he feels that trout would be adversely impacted if pH dropped significantly below six as an average. He would not expect trout populations to be able to reproduce and grow at a pH below six. (Nov. 18 Tr. at 152,153)

Parkhurst also states that a permanent pH decrease from 6.0 to 5.0 is not a natural variation and that many species would probably be eliminated and species numbers and diversities reduced. (Nov. 10 Tr. at 110)

Parkhurst also testified that there is not any evidence to show that trout are capable of both reproducing and maturing in an environment, which is consistently of a pH of 4.5 or less. (Nov. 10 Tr. at 114)

In conclusion, the record does not clearly identify the point at which damage to fish will occur. However, testimony indicates that below a pH of 4.5, and maybe below 6, fish populations would not be able to reproduce and mature.

Summary

Few definitive conclusions could be drawn from the evidence and testimony. The main point of agreement was that at the present time there has not been any adverse acidification identified in any of Colorado's watersheds. The buffering capacity of lakes appears to be the important factor to consider in determining sensitivity of lakes. Testimony was given that buffering capacity has diminished in certain mountain lakes; however, the cause of this loss has not been identified. No agreement was reached on what level of pH could be tolerated by aquatic ecosystems without causing adverse impact. It could be agreed by all parties that more research must be conducted on acid deposition so that its effects may be better understood and predicted by appropriate models.

Although more information is needed, studies in the Northeastern United States, Canada, and Europe show that acid deposition can be a serious problem (Oct. 29 Tr. at 144-145 and EDF Exhibit 32 p.3). Colorado contains many lakes, which are sensitive, exhibiting low buffering capacities. If energy development occurs on the Western Slope emissions of acid precursors will grow substantially, which will result in increased acid deposition levels. The nature of energy industry in Colorado may result in rapid growth in a short period of time, which will occur before all information on acid deposition is understood. If a large industry develops and new information shows that ambient air standards and increments do not protect the state from acidification problems, a valuable resource may be damaged. For these reasons, the Commission intends to remain vigilant in monitoring this problem, and as analytical capabilities are developed or a problem develops, to re-address this issue for possible regulatory and/or legislative solutions. A subcommittee should be formed, if resources permit, to develop specific guidelines for acid deposition analyses based on recent modeling innovations. In the interim, proposed PSD sources emitting acid or acid precursors will be required to analyze the impact of these emissions on water, utilizing the most up-to-date techniques available.

AREA CLASSIFICATIONS

Several parties objected to the application of Class I sulfur dioxide increments to those areas of Colorado listed in Section VIII.B. which are otherwise Class II areas. The sulfur dioxide Class I increments are required to be enforced in these areas by CRS 1973, 25-7-209. However, pursuant to CRS 1973, Section 25-7-105(8) (Supp. 1982), this Section VIII.S. may not be made a part of the State Implementation Plan (SIP) until these areas are redesignated as Class I under the procedures of Section IX. Until they are redesignated, they may only be enforced under state law and regulations. However, unlike Class I areas, the increment in these areas may be protected now. See CR5 1973, 25-7-210.

The Commission has also determined that the variances from increment consumption allowed by Sections XIV.C., XIV.D., XIV.E., and XIV.F. for Class I areas should also apply to the areas listed in Section VIII.B. It is a reasonable interpretation of CRS 1973, 25-7-209 that if the Class I (sulfur dioxide) increments are to apply to such areas, the variances from the increments should also apply. There is nothing in the State Act to indicate that the areas listed in CRS 1973, 25-7-209, are to be given better air quality protection than Class I areas, which would be the result if the variances did not apply.

REDESIGNATIQN

Several parties objected to what were considered burdensome requirements for redesignating areas to Class I. The adopted rule incorporates only the minimal requirements for redesignation from state and federal law. See CR5 1973, 25-7-208; Sec. 164 of the Federal Clean Air Act; 40 CFR 5l7~(g). However, the Commission did lessen the burden imposed by the proposed rule on those persons requesting a redesignation by allowing such requests to be made without providing all of the information necessary for a redesignation. Who would provide such information is not specified so that it could be any combination of federal, state and private entities.

TECHNICAL MODELING & MONITORING REQUIREMENTS

Several parties proposed the inclusion of future EPA amendments or guidelines in this Section of the regulation, which specifies the air quality model, monitoring and stack height requirements to be used. In response, the Commission adopted the use of “EPA approved” terminology instead of references to specific documents.

Two parties proposed language making EPA or the state responsible for any needed meteorological data. The Commission did not adopt this proposal because it is the applicant's responsibility to demonstrate that it will not cause exceedance of an NAAQS or increment, and meteorological data are nearly always needed to make such determinations. If the Division has such data, it has an obligation to make that data available to the applicant.

INNOVATIVE CONTROL TECHNOLOGY

Several parties proposed that the phrase “greater than or” be deleted from Section XIII.B.2. which specifies that the innovative system achieve emission reductions “greater than or equivalent to” BACT. The EPA regulation uses the phrase “equivalent to” and the parties considered the proposed state rule more stringent. The Commission does not consider the phrase “greater than or equivalent to” (emphasis added) to be more stringent, but instead to be a clarification that an acceptable innovation can result in either equivalent or lesser emissions from the source, but not a higher level of emissions. The preamble to the EPA RSD regulation (Div. Exhibit B, p. 84) clearly specifies that the “...final emission limitation must at least represent the BACT level that would have been initially defined.”

FEDERAL CLASS I AREAS

1. (Section XIV.A.) The State's Independent Determination of Adverse Impact to Visibility

   Section XIV.A. allows the Division or the Board (if applicable) to determine independently if there are an adverse impact to visibility in Class I areas if the federal land manager (FLM) fails to make such determination or such determination is in error. This authority is intended to allow the state to fulfill the FLM's responsibility for protection of visibility if for whatever reason, including political, the FLt4 fails to do so. The Commission recognizes that scenic vistas are an important resource of the State of Colorado. (Colorado Mountain Club Exhibit #1) A subcommittee may be formed to further develop visibility protection for the State of Colorado.

Several parties suggested problems with the state's independent authority' to make such visibility determinations. These consisted of (1) measuring or predicting visibility impairment, (2) quantifying man-induced , as opposed to naturally-occurring, visibility impairment, (3) the subjectiveness of visibility impairment, (4) the lack of correlation of current particulate standards to visibility impairment, and (5) the lack of guidance in the regulation regarding determinations of significant and adverse visibility impacts.

The Commission's response to these concerns is as follows:

(1) Although it is true that there are not federal reference methods for measuring visibility at this time, there are reliable means to accurately measure and predict visibility impairment. Scientific instruments such as the telephotometer, nephelometer, and the fine particulate monitor are recognized as being capable of obtaining objective information on visibility-related parameters. Photographs are also useful in visibility assessment.

Visibility theory involving scattering and absorption of light is well documented and has been incorporated into the models described in the Workbook for Estimating Visibility Impairment (EPA-450/4-8-031). The preface to the Workbook for Estimating Visibility Impairment states: “EPA believes these techniques are at a point where the results should now be employed to assist decision-makers in their assessments.” “These techniques” include the Plu-Vu Model. Div. Ex. J at iii. Thus, these models are appropriate for use at this time.

(2) It is possible to determine if a source of visibility impairment is natural or anthropogenic through various chemical/physical analysis techniques. Improvements in air sampling and analytical techniques have made available, for the first time, detailed information on the chemical and physical nature of the ambient aerosol and of source - emissions. Using these chemical “fingerprints,” particle morphology and the natural variability of airshed sources, recent developments in receptor models have provided new techniques of assigning source contributions.

(3) Perception of visibility impairment is subjective and involves individual variability; however, norms do exist around which an assessment can be made. As noted above, EPA supports the use of its Workbook for Estimating Visibility Impairment as a guide to decision-makers.

(4) Particulate standards do not address visibility-related effects. It is also true that the major anthropogenic visibility impairing pollutant is fine particulate matter. Since the Class I increment for particulate is in terms of total mass concentration, rather than fine particulates, visibility impairment could occur without the increment being violated. Furthermore, the particulate increment is a maximum allowable ground level concentration; consequently it will not protect visibility impaired by plumes at elevations above ground level. These facts form the basis for the Clean Air Act requirement that visibility should be assessed and regulated in a separate analysis. Div. Ex. S.

(5) The primary guidance for determinations of adverse impact to visibility would be the Workbook for Estimating Visibility Impairment, which has very specific guidelines.

2. (Section XIV.B.) Pre-Application and Operational Monitoring of Air Quality Related Values (AQRVs)

Section XIV.B. of the regulation allows the Division to require a source, which will have or is likely to have an impact on any Class 1 area to conduct monitoring to establish the baseline status of and impacts on AQRVs in such Class 1 areas. EPA has not imposed this requirement on applicants, although under EPA rules and the Commission rule, Section IV.D.3.(a)(vi), an Additional Impact Analysis is required which would include an analysis of impacts on AQRVs based on available data, for example, through literature searches. The data gathered from such monitoring are important and necessary in aiding the federal land manager of a Class 1 area in determining whether or not a source will cause an adverse impact on AQRVs and the state in deciding on concurrence with such determination. The data also aid the public information function of the Additional Impacts Analysis. The authority to require submission of such Information includes, but is not limited to, CRS 1973, 25-7-206(2), 25-7-106(5) and (6), and 25-7-114(4).

A. National Park Service and Forest Service Testimony and Positions

The National Park Service ("NPS") and the Forest Service ("FS") supported the rule as a supplement to their current monitoring activities on the basis that the data is necessary to determining adverse impacts on AQRV5, including visibility. See Mitchell, Nov. 18 Tr. at 122 et seq., 161 et seq.; Haddow, 0ct. 28 (p.m.) Tr. At 22 et seq., Nov. 10 Tr. at 68 et. Seq.; Region 2-USDA Forest Service Comments on Proposed PSD Rule; Comments on the May 19, 1982 Proposed Colorado PSD Regulation by National Park Service Air Quality Division.

The NPS stated its willingness to provide a list of sensitive receptors of AQRVs to applicants for monitoring Mitchell, Nov. 18 Tr. at 162.

The Forest Service recognized severe technical difficulties and high costs of monitoring some pollutants and visibility in wilderness areas. Haddow, Oct. 28 (p.m.) Tr. at 22 ~. However, lichen monitoring could be done without great difficulty and special use permits are available for some complex monitoring. Haddow, Nov. 10 (p.m.) Tr. at 112., The FS intends to identify sensitive indicators of AQRVs for each Class 1 area, e.g. 2 or 3 species of lichen and 2 or 3 scenic views, and proposes that the state require the monitoring of such indicators Id. at 82-83.

B. Environmental Defense Fund's (EDF) and Friends of the Earth's (FOE Position

EDF's and FOE's general contentions in support of the proposed monitoring requirements were:

1. the technology for monitoring of AQRV's exist;

2. the Forest Service has identified AQRV's for wilderness areas;

3. although some monitoring is being done, most areas are not being monitored and will not be without the participation of industry;

4. decisions on adverse impacts to AQRV5 cannot be made rationally without reliable scientific evidence; and

5. the state is required to have a visibility monitoring program by EPA rules, 40 CFR 51.305.

"EDF and FOE Final Recommendations; Summaries of the Record and Legal and Policy Analyses," Section IV.

C. Trade Association Parties' Position

The Trade Association Parties' general contentions in opposition to the monitoring requirements were:

1. The Clean Air Act places the responsibility on the federal land manager to determine adverse impacts on AQRVs and, thus, the responsibility to obtain the data necessary to make such determination;

2. There is insufficient information available at this time to develop an AQRV monitoring program in that sensitive receptors for each Class 1 area have not been identified, there is no monitoring reference method available and no validated models to project impacts of particular emissions levels;

3. In some Class 1 areas monitoring is either physically impossible or inordinately expensive; and

4. The Division's discretion in specifying sensitive receptors is too vague and broad.

Trade Association Parties' Closing Argument at 31-34.

D. Commission Analysis and Decision

The above-cited testimony and evidence and other portions of the record support the conclusion that monitoring of AQRVs or sensitive receptors of AQRV5 would be helpful, and in many cases necessary, to determine whether adverse impacts on AQRVs would occur. It is also evident that baseline data are not available and may never be developed by federal land managers for some AQRVs and sensitive receptors and for some Class 1 areas. Thus, the primary issue is where to place the responsibility for obtaining background data on AQRVs - the federal land manager, the state and/or the applicant.

As the Forest Service suggested, it is traditional permitting practice to require a permit applicant to obtain the data upon which the agency decides. Haddow, Nov. 10.(p.m.) Tr. at 89. This practice is consistent with the economic philosophy that companies should internalize their environmental costs. Furthermore, the Clean Air Act does not change such practice; it places the “affirmative responsibility” on federal land managers to protect AQRVs and to consider whether there will be an adverse impact on AQRVs but does not expressly state whose responsibility it is to provide necessary data upon which to exercise their responsibility.

The Commission has determined that there is available research and test methods, for obtaining background data and impact data on many AQRVs that will be critical in making adverse impact determinations, even though there are not generally adopted reference methods or modeling techniques. For example, to perform a reasonably accurate visibility impairment analysis, background data is needed. Div. Ex. J. Although there are no generally accepted reference methods for estimating visibility impacts, methods for estimating visibility Impairment have been developed and are relatively sophisticated. See Div. Ex. J.; Geier, Oct. 28 (a.m.) Tr. at 62-71. The rule recognizes this potential limitation on monitoring AQRVs by only allowing monitoring if “monitoring methods are reasonably available and research and development of monitoring methods are unnecessary.”

In response to the objection that the Division's discretion in selecting AQRVs for monitoring is too vague and broad, the rule provides:

1. A definition of AQRVs (in the Common Provisions Regulation);

2. That the Division will consult with the federal land manager in the selection of AQRVs; and

3. That the AQRVs selected must be important to the affected Class I area and there must be cause to believe that monitoring of the AQRVs will provide a basis for evaluating effects to the AQRVs.

In response to the objection that the monitoring of AQRVs may not be economically reasonable, the rule provides that:

1. no duplication of monitoring may be required;

2. not more than three AQRVs may be required to be monitored;

3. monitoring methods must be reasonably available;

4. monitoring may only be required if the source is a major contributor to the expected effects on the AQRV; and

5. it is economically reasonable as compared to other monitoring and analysis expenses required of a PSD permit applicant.

SULFUR DIOXIDE AMBIENT AIR STANDARDS FOR THE STATE OF COLORADO

The proposed rule would have revised the Colorado ambient air quality standard for sulfur dioxide to be consistent with the federal standard. Because the Colorado standard is not enforceable in the permitting process, see CRS 1973, 25-7-114(4)(g), the Commission ordered on November 10, 1982 That revisions of the state ambient air quality standard for SO2 be removed as a subject of this rulemaking.

The Commission agreed to reconsider the state standard if and when it becomes enforceable.

PUBLIC ACCESS TO CONFIDENTIAL INFORMATION

One party raised the issue of whether Section VII of Regulation NO. 3 improperly restricts access to confidential information, which would be available under the Federal Clean Air Act. Section VII may not be considered for amendment in this rulemaking due to lack of public notice.

**I.D. Adopted March 10, 1983**

**Revisions to Regulation Number 3 (Excluding PSD Program Revisions)**

This Rationale complies with the requirement of the Administrative Procedures Act, C.R.S. 1973, 24-4-103(4), to prepare a Statement of Basis and Purpose for adopted regulations. The statutory authority for these amendments are at C.R.S. 1973, 25-7-102, 25-7-105, 25-7-106, 25-7-109, and 25-7-114. These revisions to Regulation Number 3, adopted February 10, 1982, are intended to clarify and further define certain portions of the regulation adopted June 5, 1980. The 1980 revisions were extensive changes designed to reflect the new provisions of the 1979 Colorado Air Quality Control act (HB 1109); these changes reflect policy changes and clarifications to the existing rule. The basis and purpose of each revision is discussed below.

I. MINOR SIGNIFICANCE DETERMINATIONS FOR PERMIT AND APEN EXEMPTIONS

Section II.C.1.j. of Regulation Number 3 allows the Division to exempt sources from Air Pollutant Emission Notice (APEN) filing and permit requirements if the criteria in this Section are met. Since mid-1980, the Division has granted approximately 25 exemptions under Section II.C.1.j.. Of the approximately 700 permits issued by the Division annually, 55 percent are to sources with uncontrolled emissions of less than 5 tons per year (tpy); 35 percent of the total permits are to sources with uncontrolled emissions below 1 tpy. Thus, except for the specific source categories exempted by the Commission under Section II.C.1. of Regulation Number 3, nearly every air pollution source, no matter how minimal its emissions, has had to file an APEN and obtain a permit. The record supports a finding that most sources of less than one ton per year emissions and some of less than five tons per year emissions will have a negligible impact on air quality and should be exempted from the APEN and/or permit requirement.

On that basis and for the following more specific reasons and purposes the adopted revisions to Section II regarding APEN filing exemptions and to Section III regarding permit exemptions are intended to:

(a) require APEN filing and permits for any source of hazardous, toxic or odorous air pollutants, however small the source. The Commission considers the gathering of information on, and the regulation of, such pollutants to be of high priority.

(b) exempt sources of all other pollutants from both APEN filing and permit requirements when uncontrolled emissions from the source would be less than one tpy. Such sources, according to a Division study, account for less than 1 percent of total uncontrolled emissions and would be anticipated to have 24-hour impacts, at a maximum, of less than 2 micrograms per cubic meter (uglm3) assuming 24 hours per day operation, a negligible impact given the localized area of the Impact.

(c) require sources of other than hazardous, toxic or odorous pollutants whose uncontrolled emissions are less than five tpy but greater than or equal to one tpy to file an APEN. These sources would be exempt train permit requirements (with one exception) unless the Division demonstrated using specific guidelines that the source was significant. The Division would have to notify the source that a permit was required; otherwise, the source would be exempt from permit requirements. The APEN should provide all needed information to preclude unnecessary delay in making such determinations.

Emissions from these 1 to 5 tpy sources, according to a Division study, account for no more than two percent of total emissions, yet comprise 20 percent of the total sources obtaining permits. Such sources could, however, produce 24-hour ambient air impacts as high as 10 ug/m $^{3}$ , which could be significant in certain cases, especially if such source would cause a violation of a NAAQS or increment or by itself or in combination with similar sources cause a health or welfare problem or interfere with reasonable further progress towards attainment.

Volatile Organic Compound (VOC) sources are treated differently. The record demonstrates that 45 percent of the total of all uncontrolled stationary source VOC emissions are emitted by sources ranging from 1 to 5 tpy in size. Most of these sources locate in urban areas such as Denver, which is nonattainment for ozone. Since VOC emissions are an ozone precursor, such sources should be subject to permitting requirements to ensure compliance with applicable VOC emission limitations.

Therefore, VOC sources equal to or exceeding 1 tpy (uncontrolled) locating in nonattainment areas must both file an APEN and obtain a permit. VOC sources ranging from 1 tpy to 5 tpy locating in attainment areas where there is less concern for ozone will be treated like other sources and will be at least required to file an APEN.

(d) require sources of other pollutants whose uncontrolled emissions equal or exceed five tpy to file APENs and obtain permits unless specifically exempted from such requirements. These sources constitute approximately 98 percent of total uncontrolled emissions, and the Commission feels that such sources should be required to submit APENs and obtain permits unless specifically exempted as a class or as an individual source.

II. "SIGNIFICANT CHANGE" IN EMISSIONS REQUIRING THE FILING OF A REVISED APEN

The purpose of this revision to Sections II.B. and II.C. is to clarify and revise the requirements for reporting changes in emissions (either increases or decreases) to the Division.

The record shows that an acceptable emissions inventory, usually referred to as the EIS (for Emissions Inventory Subsystem), is essential for effective air quality management and that the revised APENs provide an effective system for obtaining EIS data. Revised APENs reporting significant changes in emissions are required by statute, C.R.S. 1973, 25-7-114(1), and the $40 fee for a revised APEN defrays the cost of processing the information (see "Fiscal Impact"). The levels set for reporting emissions changes are significant and will allow the effective tracking of air quality changes and use for air quality management.

It is obvious, however, that there has been confusion concerning these requirements in the past. The following statements should clarify the confusion:

A. Revised APENs reporting significant changes in emissions are to reflect actual emissions for the preceding year, not projected or maximum emissions. Actual emissions are the emissions actually emitted by a source into the atmosphere on an annual basis, determined as accurately as is feasible using production or processing or combustion rates, and emission factors, or test results, or other accepted methods for estimating emission rates. These actual emission rates are the "actual emissions used in the PSD definition of "actual emissions", except that for PSD, an "actual emission" rate can be ignored if it is not representative of "normal" operation. The APEN forms should clearly distinguish an APEN filed with a permit application (which estimates maximum anticipated production or emission levels) and a revised APEN (which reports actual emissions when a significant change in emissions has occurred). Changes in emission rates reported on a revised APEN shall not be used to modify allowable emissions rates or permit conditions for the source unless the revised APEN is filed specifically for the purpose of modifying an existing permit or obtaining a new permit, in which case the APEN must (1) be accompanied by an application, written request, or letter of explanation from the applicant and (2) reflect maximum anticipated production or emission level changes resulting from the requested action, not "actual" emissions from the existing source.

B. Each affected source should discuss with the Division the most efficient format in which significant changes can be reported and the degree to which similar emission sources can be combined for reporting purposes. It is the intent of the Commission that the Division carry out this flexible approach to the maximum extent possible in order to reduce the burden on regulated sources.

The Commission has made these revisions economically reasonable by easing the burden of reporting by allowing the use of any mutually convenient reporting format in lieu of a "standard" form and by allowing individual, but similar, emission point sources to be grouped. It should be stressed that this grouping of emission point sources for purposes of reporting significant changes to the Division does not constitute, nor does it set any precedent for, any netting or bubbling or other emission trading approach; emission trading can be conducted only through specific regulations pertaining to this activity. These APEN groupings also do not relieve the source of any obligation to meet any emission control limitations for specific point sources within the group.

In general, the reporting requirements for significant changes have been given greater latitude than existed before, partly in response to concerns that, at certain reporting levels, the accuracy requested exceeds the accuracy of the available data, and in response to EPA requirements for reporting EIS changes which are in the range of 5 tpy for small sources or 5 percent for 100 tpy or larger sources. The adopted "significant change" definition reflects a deliberate selection based on the public hearing testimony and the exhibits and testimony submitted by the Division and interested parties during these deliberations. For odorous, hazardous or toxic pollutants, any emissions change must be reported (again, on an annual basis). With changes of only 0.0004 tpy (for beryllium), for example, considered "significant" by EPA, close scrutiny of all hazardous, toxic and odorous pollutants is needed.

III. REVISED APEN FEES

An issue raised is whether the Commission has statutory authority to require a $40.00 filing fee with a revised APEN. The statutory authority for a fee states, "Any person required by the Commission to file an air pollutant emission notice shall pay a nonrefundable fee of forty dollars...." C.R.S. 1973, 25-7-114(5)(a). The statutory authority for requiring the filing of APENs and revised APENs refers to: "air pollutant emission notice" and "revised emission notice", C.R.S. 1973, 25-7-114, the latter reference being to "revised (air pollutant) emission notice". Section 25-7-114(5)(a) does not limit the $40.00 fee to initial APENs filed for a source but refers simply to "air pollutant emission notice" which may be interpreted to include both initial and revised APENs. Testimony by the Division estimated the administrative costs of processing a revised APEN at over $40.00. For these reasons, the Commission finds that it has authority and should charge a $40.00 filing fee for revised APENs.

IV. NON-PERMITTED SOURCE APPLICABILITY

A source existing before the adoption of the first Colorado Air Quality Control Act and the date of its implementing regulations of February 1, 1972, is not required to obtain a permit. This revision is intended to clarify the date prior to which existing sources are considered "grandfathered" and exempt from a permit requirement.

V. STATIONARY INTERNAL COMBUSTION ENGINE EXEMPTION

The purpose of this revision is to decrease the extent of the exemption for stationary internal combustion engines. Prior to this revision, stationary internal combustion engines less than 1000 HP in attainment areas and less than 250 HP in nonattainment areas were exempt from permit requirements. The record shows that these sources not only constitute large individual sources (a 1000 HP engine can emit 96 tpy of NOx), but also can be situated close to each other (one compressor station in Colorado consists of 15 925 HP stationary internal combustion engines which can emit a total of 1340 tpy NOx). Small stationary internal combustion engines in terms of emissions (less than 5 tpy) or size (less than 50 HP) are excluded from permit requirements. In addition, the Commission has retained the exclusion from permit requirements for emergency power generators and added exclusion for stationary internal combustion engines powering portable oil drilling rigs.

The exclusion for stationary internal combustion engines on portable oil drilling rigs is based on testimony and on information developed by the Division which indicates that these sources move frequently (average 10 days per well site), generally are located at remote sites, and emit only 1.3 tons N02 per well drilled. The Division indicated that the total estimated NOx emissions from portable oil drilling rigs in Colorado could be as high as 2200 tpy and that this could increase the total NO emissions inventory in specific active drilling areas by as much as 50 percent. To determine if an air quality problem exists for these sources, testimony from the Colorado Petroleum Association (CPA) indicates a willingness to provide the information needed by the Division to assess emissions by modifying existing data-gathering reports.

One party requested a delayed effective date for this revision so that compressor stations planned for construction during the summer of 1983 would not be held up by an unanticipated requirement that permits be obtained. Such a request is reasonable, and the delayed effective date of October 1; 1983, has been adopted.

VI. PUBLIC COMMENT FOR DEMOLITION AND NONATTAINMENT AREA PERMITS

Since the record shows that sources for which public comment has been received are in every case either large (greater than 25 tpy) or controversial (e.g., odorous emissions), the public comment requirement for sources in nonattainment areas is being raised from 5 tpy to 25 tpy, which makes it the same as for sources locating in attainment areas. Demolition projects have been exempted from public comment requirements because they often need to be completed, by contract agreement, in a short period of time, and the need for public comment has on occasion been an unnecessary time delay. Very few public responses have been received for small demolition projects. The Division retains the authority to require public comment for demolition projects if considered warranted for reasons of asbestos emissions or other significant concerns.

VII. CONSTRUCTION SCHEDULE DEADLINES

Under previous rules, owners and operators applying for new permits have not been held to any time limits for commencing construction or operation once the permit to operate has been obtained. Sources must be evaluated (C.R.S. 1973, 25-7-114(4)(b)) to determine whether operation of the source will comply with all applicable regulations, an evaluation that can be made with an acceptable degree of certainty provided that the source actually does construct and operate within a reasonable period of time following receipt of the permit. However, a source which delays construction for a number of years may finally initiate operation at a time when ambient air concentrations or other factors used in evaluating compliance have changed; in addition, delaying construction and operation results in the reserving of emissions that could have been used by other applicants.

This provision implements an 18-month construction deadline, imposed by the Division, to all sources, major and minor, statewide. Owners and operators will be prevented from applying for a permit without intending to construct in the near future, a form of “reserving” emissions or increments which makes compliance analysis difficult and could inhibit real economic growth in the state. Under these provisions, the Division will grant necessary extensions to permits that are issued, so a source with good reason for delaying a project would not be penalized by loss of a permit.

VIII. NON-REACTIVE VOLATILE ORGANIC COMPOUNDS (NRVOCs)

The EPA maintains a list of NRVOCs, which are considered either totally non-reactive or insignificantly reactive in the formation of ozone. NRVOCs can therefore be used to replace reactive VOCs as offsets.

A list of additions to this list appeared in the July 22, 1980 Federal Register. The revision to Regulation Number 3 updates the list of NRVOC5, which are non-hazardous, to conform to EPA's revised list of NRVOC. In addition to this, the revision extends the concept of NRVOC Statewide (instead of nonattainment areas only), and clarifies that NRVOCs will be reviewed separately during initial approval analysis of a new source. Previously, NRVOCs pertained to nonattainment areas only and were used only based on emission-offset credit. The revision clarifies that NRVOCs can be substituted for VOCs for banking and other emission reduction credits.

IX. CLEAN PORTION OF NON-ATTAINMENT AREA

No revisions to Sections IV.D.2.c. or IV.D.3.b. were made because the State Act provides for the exemption of Section IV.D.2.c. at C.R.S. 1973, 25-7-303.

**I.E. Adopted March 19, 1987**

**Revisions to Regulation Number 3 Section II.C.1.**

The specific statutory authority under which the Commission shall hold and conduct this hearing is prescribed by 24-4-103, 25-7-105, -106, -110, and the hearing will be conducted in accord with provisions of 24-4-103 and 25-7-110, C.R.S. 1982 and the Commission's Procedural Rules.

The revision to Regulation Number 3 Section II. C. 1. is an addition to the list of sources, which are exempt from filing Air Pollution Emission notices. Addition of Part l. (small L) to this regulation exempts petroleum industry flares, approved by the Oil and Gas Conservation Commission, from having to file an Air Pollution Emission Notice (APEN) if emissions of any pollutant do not exceed five (5) tons per year. This exemption only applies to flares, which do not combust gas containing hydrogen sulfide (H2S) except in trace amounts, since H2S is classified as a hazardous air pollutant. Previously APENS were required for these flares when emissions exceeded 1 ton per year.

The Air Quality Control Commission adopts this change for the following reasons:

1) Records of the amount of gas flared will be kept by the Oil and Gas Commission and made available to the Division;

2) The flaring is a temporary activity in most cases;

3) Statewide emissions from flares are relatively low, with nitrogen oxides ($NO_X$) being the main pollutant emitted (emissions of $NO_x$ from flares is approximately 200 tons per year statewide, while total stationary source $NO_x$ emissions are over 160,000 tons per year in Colorado);

4) Ambient impacts from flares are low;

5) No hazardous pollutants will be emitted;

6) Larger flares will still have to be permitted by the Division.

**I.F. Adopted November 19, 1987**

**Addition of Section XV to Air Quality Control Commission Regulation Number 3 Regulation Requiring an Air Contaminant Emission Notice, Emission Permit Fees**

This Statement of Basis, Specific Statutory Authority and Purpose complies with the requirement of the Administrative Procedures Act, C.R.S. 1973, Section 24-4-103 (4) for adopted or modified regulations.

This revision to Regulation Number 3, adopted November 19, 1987, is intended to bring the Colorado regulations into conformance with current U.S. EPA regulations. U.S. EPA's regulations were revised in response to a court order which required each state to develop a program to assess and remedy visibility impairment in Class I areas from new and existing sources, as established in Section 169A of the Clean Air Act.

Section XV. is added to Regulation Number 3 as part of the State's plan to meet the national goal of preventing future, and remedying existing, visibility impairment in Class I areas. Section XV. Together with this Statement of Basis, Specific Statutory Authority and Purpose and the monitoring and long-term strategies represents Colorado's State Implementation Plan (SIP).

This Regulation addresses a type of visibility impairment, which can be traced to a single source or small group of sources known as reasonably attributable impairment. The U.S. EPA deferred action on the regulation of regional haze and urban plumes due to scientific and technical limitations in visibility monitoring techniques and modeling methods.

The FLMs were consulted and their suggestions considered in developing the plan. In addition, the Commission provided public notice 60 days prior to the public hearing stating that interested parties would be given the opportunity to provide testimony concerning the Regulation and its requirements at the hearing. Wyoming, Utah and New Mexico were also sent notice of the hearing.

Section XV.D. allows the FLMs to certify visibility impairment to the Division Director at any time. At such time of certification the Division must assess the impairment, identify the contributing source(s), and conduct a Best Available Retrofit Technology (BART) analysis for any contributing sources located in Colorado. The FLMs have not certified reasonably attributable impairment as of this adoption date. Section D. also requires BART and is incorporated for future use, if necessary.

Any source subject to the BART requirements of this Section may apply to the U.S. EPA Administrator for an exemption. The application to the U.S. EPA must include a written concurrence from the Division and Commission; therefore, the source must first apply to the Division, as set forth in Section D.2.c. An exemption granted by the Division and approved by the Commission will constitute the written concurrence required by U.S. EPA.

The New Source Review requirement of Section XV.E. is included for purpose of reinforcing Sections IV.D.2.a. (vi) and IV.D.3.a. (vi).

In addition to existing and new source review, the Division must develop a visibility monitoring strategy to collect information on visibility conditions and must develop a long-term (10-15 year) strategy to assure progress towards the national goal. The monitoring plan and the long-term strategy are set forth in the SIP submitted to the U.S. EPA. Section XV.F. provides procedures for reviewing and revising the long-term strategy.

**State Implementation Plan for Class I Visibility Protection State of Colorado**

The purpose of this plan is to assure reasonable progress towards meeting the national goal of preventing future, and remedying existing, visibility impairment in Class I areas.

The plan includes provisions for existing and new source review (attached as Regulation Number 3, Section XV.), a monitoring strategy, a long-term strategy, and consultation with FLMs.

Monitoring Strategy

The State of Colorado's Class I Visibility monitoring strategy is based on meeting four goals:

1. Provide information for new source visibility impact analysis;

2. Determine existing conditions, in Class I areas and the source(s) of any certified impairment;

3. Determine actual effects from the operation of new sources or modifications to major sources on nearby Class I areas; and

4. Establish visibility trends in Class I areas in order to evaluate progress toward meeting the national goals of visibility protection.

The goals will be achieved through a combination of objectives concerning monitoring, gathering and evaluating existing visibility data, and mechanisms for the use of visibility data in decision-making.

Potential new major stationary sources or major modifications to existing stationary sources subject to the Air Quality Control Commission (AQCC) Regulation Number 3, Section IV.3, are required to perform an analysis of visibility impacts on potentially affected Class I areas. The analysis must be conducted utilizing existing visibility data, if any. The Division must consider and evaluate available data from potentially affected Class I areas or other areas that may be representative of background conditions in the Class I area(s) of interest. If data is adequate, the permittee will be notified of the background or base level of visibility against which impacts will be assessed (Regulation Number 3, Section IV.3.(a)(iii)(D)). If visibility data is not adequate, Regulation Number 3, Section XIV. allows the Division to require any source, which will have or is likely to have an impact on any Class I area to conduct monitoring to establish baseline status of visibility. The monitoring information will be used in the new source review analysis and will add to the background and trend data bank of that Class I area. No monitoring shall be required if it is currently being conducted by any federal, state, or local agency (AQCC Regulation Number 3, Section XIV.B.1).

FLMs may at any time identify to the Division Class I areas where emissions from a specific source or small group of sources may be causing or contributing to visibility impairment in the Class I area. The Division will determine if emissions from any local sources can be reasonably attributed to cause or contribute to the documented visibility impairment. In making this determination the Division will consider all available data including the following:

1. Data supplied by the FLM;

2. The number and type of sources likely to impact visibility in the Class I area;

3. The existing emissions and control measures on the source(s);

4. The prevailing meteorology near the Class I area; and

5. Any modeling, which may have been done for other air quality programs.

The Division may be unable to make a decision regarding “reasonable attribution” of visibility impairment from an existing source or sources using available data. The Division will make available to the affected FLML and the U.S. EPA a discussion of what data was considered and what measures the Division is taking, if any, to resolve the situation. The Division may consider modeling the impact of nearby suspected sources with existing visibility models. Funding and other factors may limit the Division's ability to unilaterally initiate studies designed to establish “reasonable attribution”. Therefore, the Division may join with the FLMs, the suspected source(s), the U.S. EPA , and others in implementing special monitoring and analysis programs to address the specific problem.

The Division will sponsor or share in the operation of visibility stations with FLMs as the need arises and resources allow. Fiscal, logistical, and other considerations may constrain the Division in conducting visibility monitoring in Class I areas.

The Division will request from each FLM responsible for Class I areas in Colorado copies of any and all past or existing programs designed to monitor or evaluate visibility. All future visibility data gathered by each FLM will also be requested, including any analysis and interpretation.

The Division will assemble and evaluate the visibility data supplied by the FLM in addition to any other data collected by the Division or any other appropriate source (such as a proposed major stationary source) on an annual basis.

Long-Term Strategy (LTS)

The Commission shall review the strategy set forth below and prepare a public report as required in Section XV.F. The FLMs shall be consulted throughout all phases of the LTS development and revisions.

A Commission subcommittee will be established to address the following components of the LTS:

1. Statewide visibility standards

2. Smoke management

3. Vistas

4. PM10 and PM2.5 emissions

5. Any other components the subcommittee deems applicable.

The Division is pursuing the adoption of statewide visibility standards. The subcommittee will determine how and if standards should be set and how the standards will apply to various areas of the state. Although the end result may apply to regional haze, Class I areas will benefit from statewide standards.

The Division presently has smoke management agreements with the FLMs. The affected agencies are required to obtain an open burning permit from the Division. Virtually all controlled burns are for wildlife habitat and range management; little slash/timber management burning occurs.

The Division believes existing smoke management techniques do not adversely affect visibility in Class I areas. The subcommittee will address this issue to determine how smoke management should be integrated into the LTS. If necessary, the existing agreements may be revised during the LTS review process. The Division will continue to coordinate with the FLMs to insure that best smoke management techniques are employed.

The FLMs declined to identify integral vistas (important views of landmarks or panoramas that extend outside of the boundaries of the Class I areas and considered critical to the enjoyment of the areas). The Commission is therefore not required to address vistas but may do so under their own authority. The subcommittee shall determine if integral vistas and/or other scenic vistas should be identified, and if so, the criteria to be used for such identification. Any vistas shall be identified using the specific criteria developed by the subcommittee.

The Division is in process of studying PM10 emissions and their role in the formation of Denver's brown cloud. Conceivably, such studies could lead to information and strategies related to visibility impairment. The subcommittee will address the integration of this component into the LTS.

The FLMs and Division have not identified reasonably attributable impairment at this time, therefore the Commission will not address source retirement and replacement, construction activities, and enforceability of emission limitations. Should the FLMs or Division identify impairment from a specific source or small groups of sources, the Commission will address these issues during the LTS review process.

Each time the LTS is reviewed, the following six factors (at minimum) must be addressed.

1. Emission reductions due to ongoing air pollution control programs.

2. Additional emission limitations and schedules for compliance.

3. Measures to mitigate the impacts of construction activities.

4. Source retirement and replacement schedules.

5. Smoke management techniques for agricultural and forestry management purposes including such plans as currently exist within the State for these purpose, and

6. Enforcement of emission limitations and control measures.

Consultation with Federal Land Managers (FLMs)

The Division as part of the implementation of this Regulation will send within 30 days of its adoption written notification to the FLMs stating that the Division Director is the official to whom any recommendations may be sent regarding Colorado's SIP for Class I visibility protection, including but not limited to:

1. Integral vistas to be listed by the state;

2. Identification of impairment of visibility in any Class I area(s), and

3. Identification of elements for inclusion in the monitoring strategy.

The Division will provide the opportunity for consultation with the FLMs, in person and at least 60 days prior to any public hearing on any element of the SIP. The Division is interested in the FLMs opinion regarding:

1. Assessment of impairment of visibility in any Class I area, and

2. Recommendation on the development of the long-term strategy.

The FLMs may contact the Division Director at any time regarding the implementation of the SIP for Class I visibility protection.

**I.G. Adopted August 8, 1988**

**Revisions to Regulation Number 3 and the Common Provisions Definitions**

Revisions are made to Regulation Number 3 and definitions in the Common Provisions. Prevention of Significant Deterioration (PSD) and New Source Review (nonattainment) requirements are revised to conform to the Federal regulations. Provisions for the regulation of the National Ambient Air Quality Standard (NAAQS) for particulate matter (PM-10) are added. Section V, concerning certification of Emission reduction, is revised to conform to Federal requirements. Other minor changes are made to clarify existing policies. Requirements for Revised Air Pollution Emission Notices (APENS), Air Quality Related Value (AQRV) monitoring, solid waste fuel, and temporary sources are revised.

Dual Definition of Source

Federal regulations require the use of the dual definition of source for nonattainment areas. (See discussion, in the August 7, 1980 Federal Register, 45 FR52680 and 52693). The concept is intended to provide for more air pollution control in nonattainment areas, such that more rapid progress can be made toward attaining the standards.

When determining if a source locating in an attainment area is major, emission increases and decreases at the entire facility are considered. When determining if a source located in a nonattainment area is major, two cases are examined. First, if the single piece of equipment or modification itself represents a major source or significant increase, nonattainment review applies. Second, if the piece of equipment itself is not major, examine the entire facility as for attainment area sources. If a significant increase occurs, nonattainment review applies.

The definition of “Stationary Source” in the Common Provisions indicates the Commission intended to use the dual definition (see also the Statement of Basis and Purpose, March 10, 1983). The definition of “Net Emission Increase”, Part K, however, incorrectly stated that only the single piece of equipment is examined. This was less stringent than Federal law and allowed facilities to install a series of de minimus units whose aggregate emissions could be significant, without undergoing nonattainment review. Part K is corrected to allow the Division to use the dual definition.

When the dual definition is used, nonattainment review applies to reconstructed sources. Section IV.D.2.a clarifies this.

Section IV.D.2.a also clarifies that nonattainment review applies only to nonattainment pollutants emitted in major amounts. This differs from PSD requirements, which apply to attainment pollutants emitted in significant amounts if the source is major for any pollutant (attainment or nonattainment). (See discussion, 45FR52676.)

Fugitive Emissions

The Colorado Air Quality Control act includes fugitive emissions when calculating a source's potential to emit only if the Commission adopts regulations to include fugitive emissions for that source category. (See Statement of Basis and Purpose, March 10, 1983). Federal law requires that fugitive emissions are included for all “listed” sources (those listed in the definition of major source). The Commission is adopting the requirement to include fugitive emissions for all listed sources.

Portions of the Colorado Act not Allowed in Federal Act

Portions of Regulation Number 3 are not allowed in the Federal Regulations, but are contained in the Colorado Act and therefore cannot be removed from regulation Number 3 until removed from the Colorado Act. The items are discussed below. The Division will not honor these items unless an applicant insists, in which case a permit from the EPA will be required to meet Federal law.

Best Available Control Technology (BACT):

The Colorado Act's definition of BACT states that revisions to New Source Performance Standards (NSPS, Regulation 6) or National Emission Standards for Hazardous Air Pollutants (NESHAPS, Regulation 8) made after April 10, 1983 (the effective date of the definition) can't be used to determine BACT. The Federal Act requires that BACT can't exceed the NSPS or NESHAP in effect at the time of application. The Division will make BACT determinations taking into consideration the most current NSPS and NESHAP regulations.

Clean area in nonattainment area: The Colorado Act and Section IV.d.2.B.ii allows exemption from nonattainment requirements if the source proves they are located in a clean portion of a nonattainment area. This is not allowed in the Federal Act.

Shale oil exemption: The Colorado Act and Section I.B.2.C.viii excludes from the definition of major modification a fuel switch to shale oil or coal/oil mixtures. This is not allowed in the Federal Act.

Fugitive Dust Exemption: The Colorado Act and Regulation Number 3 does not include fugitive dust that does not adversely affect public health or welfare when calculating a source's potential to emit. The

March 10, 1983 Statement of Basis, Authority, and Purpose discusses the Commission's previous position. - The discussion indicates that when the EPA promulgates new standards for particulate matter the fugitive dust issue will be resolved. The EPA has promulgated a new NAAQS for PM-10, which replaces the TSP NAAOS. The PSD increments, however, are still based on TSP. PM-l0 fugitive emissions can thus be used to determine potential to emit, but some question remains as to whether or not TSP fugitive emissions should be used. The EPA is developing PM-10 increment standards. In the interim, if a source does not want to include fugitive dust (TSP or PM-10) for a State permit, an EPA permit may have to be obtained.

Permit Review Time Frame: The Colorado act contains specific time frames for processing permits (60 days, etc.). Section IV.F of Regulation Number 3 states that a permit is automatically issued if the Division fails to meet the time constraints. This is not acceptable for major source review. PSD and major nonattainment applications are often complex. The Federal Act allows one year to complete the review process (including public notice, hearings, etc). The Division will automatically ask for a time extension for major source applications. If an extension is not granted and/or the time frame is not met, an EPA permit will be required.

Other Minor Revisions

These definitions are revised as follows to conform to the Federal Act: “construction” now includes demolition and modification; “enforceable” now includes Regulations Number 6 and 8; “Lowest Achievable Emission Rate” does not allow BACT to be exceeded.

References to the “Board” are deleted and replaced with “Commission” throughout the Regulation. The (Hearings) Board no longer exists.

Class I areas in neighboring states are recognized in Section VIII.

Section VIII.K is added to allow redesignation of an area to class III if a permit can't be obtained unless the area is redesignated and sufficient public notice is given. The Federal Act requires this.

Section XIII.B exempts Innovative Control Technology from BACT only, not all of the PSD requirements. This conforms to the Federal Act.

Public notice procedures (Section IV.C) for major sources are expanded and clarified to conform to the Federal Act.

The word “new' is removed from Section IV.D.2.a.iv to clarify that alternate sitting studies apply to new and modified sources.

Exemption c under the definition of modification is removed. This exemption allowed sources choosing to improve control of particulate matter to increase SO2 emissions without the need for>additional S02 control. (See Statement of Basis, Authority and Purpose, March 10, 1983). This exemption is no longer allowed, since it is inconsistent with the Federal Act.

The language pertaining to interim PSD authority is deleted. The State received full authority on September 2, 1986.

Annual fee requirements are added to Section VI. This provision was added to Section 25-7-114(5)(a) of the Colorado Act on July 1, 1987.

Household use of paints and solvents is exempt from APEN and permit requirements. The Division classifies these materials as toxic air pollutants which would require permits if emitted in any amount. The Division does not have available resources to regulate this activity.

The six-month, 25 acre APEN and permit exemption clarifies that all mining operations must obtain a permit (unless exempt elsewhere).

Temporary sources operating less than one month may receive initial and final permits at the same time. The Division will thus avoid issuing final permits for sources that no longer exist. The Division has discretion to issue the permits separately if the operator or owner of the source or the source type has a history of compliance problems.

PM-10 NAAQS

This new standard replaces the Total Suspended Particulate (TSP) standard for Federal purposes only. The State is adopting the PM-10 requirements and is also retaining the TSP standard at least until the EPA approves our PM-10 State Implementation Plan. This will ensure that Reasonable Further Progress will be maintained in the interim.

The PM-10 standard is implemented under Section 110 of the Federal clean Air Act. The other criteria pollutants are regulated under Section 107, which includes provisions for designated nonattainment areas, emission offsets, and sanctions for areas where the standard is exceeded. Section 110 does not utilize nonattainment areas; it requires that the standard be met in all areas. The State regulations applied specifically to designated attainment and nonattainment areas. Since there are no PM-10 designated areas, reference to pollutants regulated under Section 110 is added in several places to ensure regulation of PM-10.

PM-10 sources that impact an area where the standard is exceeded are “major” if they emit 100 tons per year or more of PM-10. Such a source is then subject to PSD requirements (Section I.4.a). Such sources must also offset their impact to the degree which it exceeds the standard (as opposed to sources of other criteria pollutants, which must offset total emissions). Offsets will be required as part of the PSD source impact analysis, as necessary.

PM-l0 fugitive emissions are included when calculating potential to emit. (See discussion under Portions of the Colorado Act not allowed in Federal Act in this Statement of Basis, Authority and Purpose).

PSD increments are still regulated in the TSP form, therefore significant emissions and impact levels exist for both PM-10 and TSP. PSD will apply to TSP until the EPA promulgates PM-10 increments.

New definitions are added to the Common Provisions to differentiate between particulate matter, PM-10 and TSP.

The EPA has left regulation of minor sources to the state. Section IV.D.3.E is added to require minor sources locating in areas where the PM-10 standard is being exceeded to apply BACT.

The Commission had the option to add PM-10 monitoring “phase in” provisions. Methods and equipment are reasonably available, therefore, phase in is not necessary.

Corrections to typographical errors are made for significant ambient levels of beryllium, lead, and hydrogen sulfide. (Section IV.D.3.b.iii)

Revised Air Pollution Emission Notices (APENS)

Section II.B requires Revised APENS when a significant change in emissions occurs. The definition of net emission increase requires that a Revised APEN be filed to receive credit for decreases. Historically, the Division has not received all of the APENS required. The April 1 deadline and calendar year requirement are added for clarification. The removal of a piece of equipment represents a significant change and the requirement for submittal of an APEN to cancel a permit is added for clarification. These clarifications will help the Division update the Emission Inventory System; proper credit will be received for emission decreases; and sources will avoid being charged an annual fee for equipment, which no longer exists.

The Regulation now requires all portable sources to submit revised APENS prior to relocating, regardless of the length of time at the new site. This helps the Division track sources in the event complaints are received.

Air Quality Related Value (AQRV) Monitoring

Section XIV.B.4.c limited the cost of AORV monitoring to 1/4 of the cost of the Additional Impact Analysis, including preconstruction monitoring. The Federal Land Managers testified that such a limit is not sufficient to provide even minimal AQRV monitoring. The limit is removed and the Division will determine economic feasibility on a case-by-case basis.

Section XIV.B.1. is revised to require joint monitoring among all major sources affecting an AQRV in the same Class I area. This will provide for ongoing, high quality data.

Waste Fuel Exemptions

Sections I.B.2.C.iii and IV.D.1.c.i (F) exempted switches to fuel derived from municipal solid waste from new source review. Due to the public's increased concern for toxic/hazardous emissions, many sources now undergo scrutiny for such emissions. All sources should be treated equally when proposing to burn municipal solid waste and should be required to apply the best control for reducing toxic/hazardous emissions. The exemptions for solid waste fuel are deleted.

Emission Reduction Credits

Revisions made to this portion of the Regulation are based on the Emission Trading Policy Statement; General Principles for Creation, Banking and Use of Emission Reduction Credits as published in 51FR43814. That Policy set out general principles that EPA will use to evaluate emission trades under the Clean Air Act. The goal of that Policy is to create more flexibility for the states and industry to help meet the goals of the Clean Air Act more quickly and inexpensively. The purpose of Colorado adopting the salient points of that Policy is to create a generic regulation, which is acceptable to EPA, and thereby eliminate the need for a SIP revision for every banking or emission trading action. Other than clarifications and procedural changes the key changes to this portion of the Regulation include:

a. A greater than 20% discount will be taken in areas without approved SIPs. The discount will be based on the level of reduction in emissions needed in that area to achieve attainment status.

b. Added provisions for trading of PM-10, lead and NOx

c. Added new criteria for modeling to determine ambient equivalence of trades.

d. Shutdowns and curtailments in production emission reductions may be used for on-site replacement of equipment only.

e. Specify no credit allowed for reduction in emissions from mobile sources unless those sources were subject to ambient impact and new source review.

f. Credit for switching to a cleaner fuel is given only if a permit is conditioned to require control equipment to achieve the same reduction if the source switches back to the dirtier fuel.

**I.H. Adopted September 15, 1998**

**"A Regulation Requiring Air Contaminant Emission Notices, Emission permits and Fees"**

With the passage of HB 1372, 1st session of the 56TH GA, two stationary source fees were established for FY 1987-88. An annual compliance-monitoring fee of $60.00 per source was to be charged .to each permitted source. An hourly rate of $96.00 was to be applied to all permit processing time. After 1987-88 these fees were to be set by the Commission. These fees were to cover the "direct and indirect costs of such permit] processing. In establishing such fees, the Commission shall provide a higher per hour charge for permits which require five hours or more than for permits which require less than five hours to process; except that for the fiscal year 1987-88, the fee shall be ninety six dollars per hour for all permits. In addition to such fee for processing, the Commission shall establish and as necessary revise non-refundable annual fees for each emissions source covered by a stationary source permit sufficient to cover the direct and indirect costs of administration and periodic inspections; except that for the fiscal year 1987-88, the fee shall be sixty dollars per year for each emissions source."

The Division has performed a thorough analysis of the direct and indirect costs of the permit and compliance monitoring programs and has proposed fees to the Commission designed to meet statutory requirements.

Statutory Authority

The statutory authority for this regulation is Section 25-7-114.

Section VI - Fees

A. General

Paragraph 1 of this Subsection requires that all persons required to obtain an emission permit or file an air pollution emission notice pay fees sufficient to recover the direct and indirect costs of processing and issuing permits in accordance with the fee schedule shown in the Regulation. With this regulatory change, the following language was struck to be consistent with the statutory language: '...to include the reasonable costs of such processing or administration, and of enforcement of the permit provisions. Such costs shall include the cost of predictive model utilization when the use of such models is deemed necessary by the Division for proper evaluation of the permit application." Paragraph 2 is unchanged.

Sub-Sections B and C are unchanged

D. Annual Fees

Sub-Section D is changed by noting that the annual fees to be charged are in accordance with the schedule shown in the Regulation.

Fee Schedule

The fee schedule shows what the fees are for the hourly processing charge, the annual charge, and the APEN.

**I.I. Adopted August 20, 1992**

**Revisions Concerning the Long-Term Strategy to Protect Visibility in Class I Areas (Section XV.F)**

Authority

Colorado Air Quality Control Act

The Colorado Air Quality Control Commission's (Commission) authority to revise Regulation Number 3.XV.F, concerning the Long-Term Strategy Review of Colorado's State Implementation Plan for Class I Visibility Protection, is in the Colorado Air Quality Control Act. Relevant Sections are 25-7-102 Legislative declaration and 25-7-105(1)(a)(I) Duties of Commission.

Federal Clean Air Act

Additional authority for the Commission to make the regulatory revisions can be traced to the 1977 Amendments to the Federal Clean Air Act. Section 169(A) requires the federal Environmental Protection Agency to promulgate regulations that in turn require states to amend their State Implementation Plans (SIPs) to provide for Class I visibility protection - including a long-term strategy for making reasonable progress toward the national visibility goal. On December 2, 1980, EPA released final regulations to states detailing the specific requirements - including the development and periodic revision of a long-term strategy as specified by federal law.

Statement of Basis and Purpose of Changes to Regulation Number 3 Section XV.F.

Section XV.F.1.c.

Commission Regulation Number 3 required a Long-Term Strategy (LTS) review/revision report from the Colorado Air Pollution Control Division (Division) to the Commission every three years following the effective date of the regulation (November 1987). The August 1992 LTS report from the Division is late in arriving to the Commission. The purpose of the regulatory change is to clarify when subsequent LTS review and revision report cycles will occur. Without a regulatory change, the next LTS review would be due September 1993 - approximately a year from adoption of the August 1992 report.

In order to maintain the intent that a report is to arrive to the Commission, and ultimately EPA, at least every three years and to allow the Division to get back on schedule with a report to the Commission in approximately three years, Section XV.F.I.c. was altered.

Old language:

> (c) The Division shall prepare a report for the Commission on any progress made toward the national visibility goal since the last long-term strategy revisions. The report will be made available on September First of every third year following the effective date of this regulation. This report shall include an assessment of:

New language (changes underlined):

> (c) The Division shall prepare a report for the Commission on any progress made toward the national visibility goal since the last long-term strategy revisions. The report will be made available by September First at least every third year following the submittal of the previous report. This report shall include an assessment of:

Section XV.F.I.c.vii

EPA regulations (CFR Part 40 Section 51.306) require that the LTS be reviewed in seven areas. There was a discrepancy between EPA requirements and State regulations regarding the seventh item to be assessed. The purpose of the regulatory change is to bring Commission Regulation Number 3 into conformance with EPA requirements.

Old language:

(vii) The progress achieved in developing the components of the strategy.

New language (changes underlined):

(vii) The need for BART to remedy existing impairment in an integral vista declared since plan approval. I.D. Adopted November 19, 1992

**I.J. Adopted November 19, 1992**

**Revisions to Regulation Number 3, Common Provisions and Regulation Number 7**

This Statement of Basis, Specific Statutory Authority and Purpose complies with the requirements of the Administrative Procedure Act, C.R.S. 1973, Section 24-4-103(4) for adopted or modified regulations.

Basis

The EPA has identified portions of the State's Prevention of Significant Deterioration and New Source Review (PSD and NSR) rules, which do not conform to the Federal rules. The State rules must be at least as stringent as the Federal rules in order for the EPA to approve the State Implementation Plans. In addition, the State must revise the rules to include the addition of new requirements that were set forth in the 1990 Federal Clean Air Act. The EPA has also identified additional non-reactive volatile organic compounds, and a significant level for municipal waste combustor emissions. All of these revisions must be made for EPA approval.

The 1992 State Legislature revised the Colorado Clean Air Act to include new definitions and fee requirements. In addition, the revisions allow the Commission to make necessary revisions to the State's PSD and NSR rules, as described above.

Specific Authority

The specific authority for this regulation is contained in the Colorado Air Quality Control Act, 1992 as amended. Section 25-7-103 sets forth definitions for use in implementing the new Colorado Act. Section 25-7-105 (1)(A)(I) requires the Commission to adopt into the State Implementation Plan all requirements of the federal act. Sections 25-7-105(1)(c), 203, 204, 205, 206, 210 and 301 provide authority to adopt a PSD and NSR program in conformance with the Federal and Colorado Acts. Section 25-7-105.1 sets forth the Commission's authority regarding Federal enforceability. Section 25-7-106 (1)(c) provides authority for adopting regulations, which are applicable to entire state, or only within specific areas or zones, or only to a particular pollutant. Section 25-7-114.5 sets forth time frames for the Division to review permit applications, and procedures for owners and operators to demonstrate compliance with construction permits. Section 25-7-114.7 sets forth fee requirements. Commission action in promulgating these revisions is taken pursuant to Sections 25-7-105 through 25-7-109 and 25-7-114, C.R.S., as amended.

Purpose

New Source Review Rules

Regulation Number 3 contains the permit requirements for major sources (Prevention of Significant Deterioration, PSD and New Source Review, NSR). The Common Provisions Regulation contains definitions that are used in the permit requirements of Regulation Number 3. The PSD and NSR requirements and definitions must be equivalent to the Federal requirements. The EPA has identified the portions of Regulation Number 3 and the Common Provisions, which do not conform to the Federal rules. On October 17, 1991, the Commission adopted revisions to Regulation Number 3 and the Common Provisions, to address some of the EPA's concerns. Additional concerns remained, however, because some of them could not be addressed until the Colorado Clean Air Act was revised. On May 27, 1992, the Governor signed Senate Bill 105, which revised the Colorado Clean Air Act to allow the Commission to proceed with the remaining necessary revisions to Regulation Number 3 and the Common Provisions. The new Colorado Act is effective as of July 1, 1992.

The 1990 Federal Clean Air Act revisions set forth additional revisions, which must be made to all State PSD and NSR rules.

The Commission has adopted the necessary revisions, which address the remaining EPA concerns regarding the State's PSD and NSR rules. These revisions are required to eliminate discrepancies between the State and Federal rules, and for approval of our State Implementation Plan. The required revisions are as follows.

Regulation Number 3

1. The regulation previously allowed sources of fugitive emissions to be exempt from the NSR and PSD requirements. The Federal Act does not allow the exemptions. Several Sections throughout the regulation needed to be revised or eliminated:

   Section I.E. - Eliminate the reference to the definitions of major stationary source and major modification from the definition of fugitive dust;

   Section I.B.3.e. and f - Eliminate the references to fugitive dust from the definition of major source;

   Section IV.D.3.b.(i)(B) - Eliminate the fugitive dust exemption from the PSD rules;

   Section XI - Eliminate the fugitive dust exemption from increment consumption requirements.

2. Section I.B.2, Section (vii) of the regulation allowed sources, which switched from oil or gas to a coal-derived fuel (shale oil) to be exempt from the PSD and NSR requirements. This is not allowed under the Federal Act, therefore (vii) is removed from the definition of major modification.

3. The new Federal Act requires major sources in nonattainment areas obtain to offsets from sources that are also located in the same nonattainment area, unless a source outside of the area contributes to nonattainment in the area in which the major source is located. Section IV.D.2.a(iii) is revised to add this new requirement.

4. The Federal Act does not allow major sources located in a “clean portion” of a nonattainment area to be exempt from the NSR requirements. Section IV.D.2.c.(ii) is revised to eliminate the clean portion of a nonattainment area exemption.

5. Section IV.D.3.e. required minor sources which contribute to the exceedance of an ambient air standard in a non-designated area (not designated attainment or nonattainment) to apply best available control technology. This requirement was previously adopted to comply with the EPA's interim policy for the PM-10 ambient air quality standards. The provision applied until the EPA was able to formally designate areas as attainment or nonattainment for PM-10. Now that the EPA has designated areas, the PSD and NSR (nonattainment) rules apply and Section IV.D.3.e. has been removed.

6. The regulation previously stated that certain permit conditions had to be removed from the permit upon issuance of final approval. The conditions on a final permit were limited to the list of items required to obtain a permit. The Federal Act requires that permits must contain all conditions necessary to ensure compliance with all applicable requirements, and any conditions necessary to make limits on production rates, hours of operation, the potential to emit, etc. federally enforceable. The language that limits the enforceability of permit conditions after Final Approval is removed from Section IV.E.

7. The Federal Act does not allow automatic approval of permits if the State fails to meet processing deadlines. The language that provides for automatic approval of permits if processing deadlines are not met is removed from Section IV.F. Likewise, confidentiality determinations do not affect the time constraints in the regulation. Section VII is revised to reflect this.

8. The new Federal Act does not allow reductions of pollutants required to meet any Act requirements to be credited for use as offsets. Language is added to Section V.E.9 of the State's Emission Reduction Credit rules to clarify this requirement.

9. The new Federal Act no longer limits the boundaries of Class I areas to those that existed in 1977. Section VIII is revised to eliminate this restriction.

10. The Federal rules state that if innovative technology is used by a PSD source, they are only exempt from the BACT requirements, not all of the PSD requirements, and that the consent of governors of other affected states must be obtained. Section XIII previously exempted such source from all PSD requirements. The Section is revised to clarify this allowance.

Common Provisions Definitions:

1. The EPA has added visible emission standards to applicable emission limitations under the definition of Best Available Control Technology. The State's definition is likewise revised.

2. Under the new Federal Act, Asbestos, Beryllium, Mercury, and Vinyl Chloride are now regulated under new hazardous pollutant requirements (Maximum Achievable Control Technology). These compounds are no longer subject to Prevention of Significant Deterioration (PSD) requirements (which would require Best Available Control). The definition of significant, which determines when a source is subject to PSD, is revised to omit these pollutants.

The Federal rules do not allow an exemption from PSD and NSR rules for right of ways, pipelines, etc. The definition of stationary source is revised to delete this exemption.

Non-Reactive VOCs:

On March 18, 1991, the EPA added five halocarbon compounds and four classes of perfluorocarbons to the list of organic compounds, which are negligibly reactive, and thus exempt from regulation as Volatile Organic Compounds under Regulation Number 3, the Common Provisions, and Regulation Number 7. In addition, the EPA revised the definition of Volatile Organic Compound.

The Non-reactive Volatile Organic Compound (VOC) list, as amended by the EPA, is incorporated into Regulation Number 3, Section IV.D.4, the Common Provisions (definition of Net Emission Increase, paragraph h.), and Regulation Number 7, Section II.B. The State is not allowed to take credit for controlling these compounds in our SIP. In other words, sources cannot use reductions of emissions of these compounds to offset VOC emissions, and we are not allowed to include emissions of these compounds in our SIP inventory. The EPA has determined that these compounds do not react in the atmosphere to produce ground level ozone.

The EPA also revised the definition of "Volatile Organic Compound" to make slight clarifications. The definition in the Common Provisions and in Regulation Number 7, Section II.A.1. is likewise revised.

Municipal Waste Combustor Emissions Significant Level:

On February 11, 1991, the EPA promulgated New Source Performance Standards for Municipal Waste Combustors. In addition, the EPA promulgated "significant emission levels" for municipal waste combustor emissions. These significant levels are used to determine if PSD requirements apply to major sources.

The Commission revised the definition of "Significant" in the Common Provisions Regulation, to add the emission level for municipal waste combustor emissions. This addition is required in order to conform to the Federal PSD and NSR rules.

Senate Bill 92-105 Revisions

Senate Bill 105 revised the Colorado Clean Air Act. The new Colorado Act contains some new and revised provisions which are relatively simple and straightforward, and which could therefore be easily adopted into Regulation Number 3 and the Common Provisions at this time. These particular revisions were adopted to facilitate transition from the old Act to the new Act, and to eliminate confusion that could occur due to differences between the new Act and the existing regulations. The proposed revisions are as follows.

Regulation Number 3

1. Sections IV.B.3, 4 and 5 - The new Act gives the Division 60 days (instead of the previous 20 days) to determine if an application is complete. In addition, the Division has 12 months to complete the application process for PSD construction permit applications (previously limited to 135 days).

2. Section IV.C.1.c - Change the reference date for the definition of hazardous pollutant. A new definition has been adopted in the new Act. The definition includes the list of 189 chemicals from the Federal Act, and an additional list contained in the Colorado Act.

3. Section IV.H - Change the procedures for granting of final approval construction permits. Previously, the Division had only 30 days once a source commenced operation to inspect the source to determine that all permit conditions were being met. The source now has 180 days to demonstrate compliance. Also previously, the Division could allow a source additional time to come into compliance before Final Approval was issued. Now the Division must grant Final Approval or revoke the permit.

4. Section VI - The new Act sets forth new fee schedules for permits, annual fees, and APENS. The permit fees have changed from a schedule based on the type of facility to $50 per hour for all applications. The Division cannot exceed 30 hours in processing time unless the applicant is first notified that 30 hours will be exceeded. The annual fees are no longer based on the number of sources at, or the size and complexity of a facility. Instead annual fees are based on actual emissions. The APEN fee has changed from $60 to $75 for fiscal year 92.

Common Provisions

1. Section I.C - Incorporates the new Legislative Declaration of the new Act. The new declaration adds to the existing declaration that an accurate emission inventory is necessary for implementation of the air quality requirements.

2. Incorporates the new Acts definition of Air Pollutant. The definition is the same as previous except that precursors are now also considered" air pollutants." Precursors can be emissions such as nitrogen and sulfur oxides, which can contribute to particulate matter emissions.

3. Revise definition of Emission Control Regulation. The new definition is the same, except such regulations can now include work practices and design, equipment, and operational standards. In addition, such regulations that apply to hazardous pollutants must be consistent with the new Act requirements concerning hazardous pollutants.

4. Revise definition of Federal Act to reference 1990. (Previously referenced 1977.)

5. Revise the definition of Federally Enforceable to indicate that the Division has authority to issue permits to synthetic minor sources.

6. Revise definition of Hazardous Air Pollutant. The new definition includes the pollutants listed under the Federal and Colorado Acts.

7. Refers to Adverse Environmental Effect, therefore this definition is added.

8. Add definition of Ozone Depleting Compound. The fee schedule requires the Division to charge fees for emissions of such compounds, therefore the definition is added. I.E.

**I.K. Adopted June 22, 1993**

**Revisions to Regulation Number 3 Regarding Construction Permits**

This Statement of Basis, Specific Statutory Authority and Purpose complies with the requirements of the Administrative Procedure Act, C.R.S. 1973, Section 24-4-103(4) for adopted or modified regulations.

Basis

The Colorado Clean Air Act requires stationary sources to report their emissions, obtain construction permits, and be subject to public notice before construction occurs. The Commission has authority to exempt sources from these requirements, if the sources do not have a significant adverse impact on air quality. Regulation Number 3 has been in effect for approximately twenty years, and contains exemption lists for APEN and permit requirements. Based on twenty years of experience, the Commission believes it is appropriate at this time to revise the exemption lists to include additional sources, which do not adversely affect air quality in Colorado. In addition, it is appropriate to revise the public notice requirements to address the sources for which is public comment is most likely to be received.

The 1992 State Legislature revised the Colorado Clean Air Act to include new provisions concerning non-criteria pollutants. The Commission needs to address these provisions and revise the APEN reporting, permitting, and public notice requirements regarding these pollutants.

A technical revision must be made to the definition of "significant," contained in the Common Provisions, to address major sources in nonattainment areas, as required under the Federal Act.

Specific Authority

The specific authority for this regulation is contained in the Colorado Air Quality Control Act, 1992 as amended. The Legislative Declaration, Section 25-7-102, recognizes that an accurate emission inventory is needed in order to adequately manage air resources in Colorado. Section 25-7-105 (1)(A)(1) requires the Commission to adopt into the State Implementation Plan all requirements of the federal act. Sections 25-7-105(l)(c), 203, 204, 205, 206, 210 and 301 provide authority to adopt a PSD and NSR program in conformance with the Federal and Colorado Acts. Section 25-7-105(12) provides authority to adopt regulations to implement the emission notice and construction permit programs. Section 25- 7-106 (1)(c) provides authority for adopting regulations, which are applicable to the entire state, or only within specific areas or zones, or only to a particular pollutant. Section 25-7-109.3 provides authority for regulating non-criteria pollutants. Section 25-7-111 provides authority for the Division to administer regulations adopted by the Commission. Section 25-7-114.1 provides authority for requiring APENS, and for allowing exemptions from the requirement. Section 25-7-114.2 provides authority for requiring construction permits, and for allowing exemptions from the requirement. Section 25-7-114.5 provides authority for requiring public notice of construction permits. Commission action in promulgating these revisions is taken pursuant to Sections 25-7-105 to -109 and 25-7-114, C.R.S., as amended.

Purpose

Definition of "Significant"

The Common Provisions Regulation contains definitions that are used in the Prevention of Significant Deterioration (PSD) and New Source Review (nonattainment, NSR) permit programs of Regulation Number 3. The PSD and NSR requirements and definitions must be equivalent to the Federal requirements. The definition of significant lists emission levels at which modifications at major sources become subject to the PSD and NSR requirements. Currently, the language in the definition indicates that the emission levels only trigger PSD requirements. The definition is changed to indicate that the levels also apply to the NSR nonattainment rules.

APEN Requirements - General

This language is revised to clarify what emission estimates must be included in an APEN (actual emissions for annual fee purposes, and requested amount for permit limits). In addition, language is added to clarify that a source need not perform a stack test for the sole purpose of providing an APEN emission estimate. Other acceptable estimation methods are usually available for APEN purposes. In some instances, it is possible that an emission factor may supply a more accurate estimate than mass balance calculations, and vice versa. In such cases, a source may choose to use either mass balance, or emission calculations. If the Division believes that estimates can be better made using the method of these two that the source does not choose, the Division may question that source regarding the choice. The emission estimate included in an APEN is not required to be an exact calculation of emissions, but rather the source's best estimate, to the extent practical, of emissions. As stated in the Legislative Declaration of the Colorado Air Quality Control Act, the APEN information is to be used to achieve the most accurate and complete inventory possible, and to provide for the most accurate enforcement program achievable based upon that inventory.

The Colorado Clean Air Act states that APENs are valid for five years, unless a significant change in emissions occurs. This provision is added to the regulation.

Language is added to clarify that each unit is considered to be a "source" for APEN purposes, unless similar sources can be grouped together.

Emission calculations for purposes of determining if a de minimis emission level is triggered will be based on actual uncontrolled emissions. Sources will not be allowed to take credit for control devices in the de minimis calculation because the Commission has no method of determining if the control equipment will be used, or used continuously and properly.

The Commission believes there may be cases where the source demonstrates that it is not feasible to estimate the control efficiency of a device for non-criteria pollutants. In such instances, the Commission gives the Division discretion to allow the de minimis level to be triggered based on actual, instead of uncontrolled actual, emissions. New language is added regarding non-criteria pollutant APEN requirements.

Revised APEN Requirements

The Colorado Act requires revised APENs to be submitted whenever a "significant change" in emissions occurs. The significant levels for criteria pollutants remain unchanged from the previous regulation, except that a significant level has been added for lead emissions. For non-criteria pollutants, the significant change level is set at 50% or five (5) tons per year, whichever is less.

Sources should note that APENs must be submitted if the source begins to emit a pollutant which was previously not included on an APEN. Also, the Commission may add pollutants to the list of non-criteria reportable pollutants. When chemicals are added, the Commission will determine the schedule for submitting new or revised APENs to report the new pollutant emissions.

NOTE: Significant change criteria are used to report changes in emissions for inventory purposes only. If a planned change in emissions requires a new permit, or modification of an existing permit (violates an emission limit, triggers PSD or NSR), then an APEN must be filed and the permit must be revised before the change at the facility occurs.

Revised APENs for emission updates must be submitted by April 30 of the following year. The EPA requires states to update the emission inventory by July 1 of each year, to include the previous year's emissions (Code of Federal Regulations, 40 CFR 51.321). The Commission believes the April 30 date should give sources enough time to compile their inventory, and will also give the Division enough time to update the system by July 1. Sources should plan ahead and have as much of their inventory completed as possible before the end of the year. In this way, the source would then only need to add December, or at worst information for the last couple of months of the year, to the data in order to meet the April 30 deadline.

Revised APENs are required when a change in the type of control equipment being used is made. This allows the Commission to ensure that the new control equipment will meet the applicable requirements, and to verify that actual emissions have decreased or increased due to the use of the new equipment. Oftentimes, stack tests are required to ensure that control equipment meets applicable requirements. A change in the control equipment can affect this compliance determination. Revised APENs will not be required for routine maintenance, repair and replacements. These routine activities should not affect the effectiveness of the equipment.

Permit applications must include an APEN on which the owner or operator indicates what production or emission level the source wishes to be permitted at. Any desire to increase the permitted emission level requires the submittal of a revised APEN, so that the Division can evaluate the change against the regulations before modifying the permit.

Portable Facilities

Revised APENs are no longer required when a portable source changes location. The Commission does not believe it is reasonable to charge the APEN filing fee each time a source moves. Portable sources will still be required to notify the Division at least ten (10) days before relocating. This allows the Division to be aware of a source's location if any concerns regarding the source are raised by the public.

Emergency and Backup Generators

Electric utilities may use emergency or backup generators to ensure that blackouts do not occur in the electrical grid. These units are usually operated instead of, or for short periods in addition to, main utility boilers. Facilities that include the main boilers are usually major sources, and therefore have a major source construction permit, or will in the future have a major source-operating permit. Once the facility is covered under one of these permits, the Commission sees no need for the owner or operator to submit annual updates regarding the emissions from the emergency units.

Other emergency units are not located at the main unit facility, but are located individually in the field. These units will most likely obtain a synthetic minor permit to avoid major source permit requirements, since operation is usually intermittent. Once such sources obtain a synthetic minor permit, the Commission again will not require the source to submit annual emission updates.

APEN Requirements - Non-Criteria Pollutants

There are 363 non-criteria reportable pollutants. The Commission divided the pollutants in two major groups: those that are required to be reported in 1993, and those that have to be reported in 1994 and subsequent years. There are also two groups of chemicals (Radionuclides and Polycyclic Organic Matter) whose reporting requirements were postponed until such time as the Commission determines that they can be accurately quantified and reported.

APEN Requirements - De Minimis Levels

All de minimis levels are based on uncontrolled actual emissions (except where the control efficiency cannot be estimated), as discussed above under General APEN Requirements.

APENs are required of sources in attainment areas when the emissions of any criteria pollutant from a source exceed two tons per year (except for lead).

Sources in nonattainment areas must file when emissions of any criteria pollutant exceed one ton per year. Note that the pollutant being emitted above the de minimis level does not have to be a nonattainment pollutant. Any pollutant triggers the one-ton per year level, regardless of the pollutant's attainment designation.

Because the area is a growth area, and inversions occur in the area, a Grand Junction group requested that APENs be filed when emissions of any criteria pollutant exceed one ton per year. The Commission determined that hearings should be held in the Grand Junction area, and that Grand Junction should pursue their own rules. Language that would have treated Pueblo likewise is not included, due to requests from industries in Pueblo, and the Pueblo County Health Department.

The de minimis level for lead in all areas is 100 pounds per year.

For non-criteria pollutants, the Commission assigned each pollutant to one of three “bins” based on information concerning the health effects of the pollutant. The Commission also developed a series of three scenarios for an emission point based on the release height of the pollutant and the distance from the release point to the property boundary. The resulting three by three grid as well as instructions on how to apply it can be found in Appendix A. Note that future actions by EPA may effect the de minimis reporting levels for certain chemicals that appear on the EPA list of 189 toxic chemicals.

APEN Requirements - Exemption List

Numerous new source categories have been added to the APEN exemption list. Each category was examined for its impact on air quality in Colorado before being added to the list. Each category that was added is believed to have a negligible impact on air quality.

The source category exemptions override the de minimis levels. Sources that fit into the category are exempt, even if emissions exceed the de minimis levels.

Each category will not be addressed individually in this statement, however the following categories deserve specific comment.

Fires and equipment used for cooking of food for human consumption: Not all cooking equipment has been exempted in this category. The Commission has concerns regarding equipment in which grease from the food being cooked comes into contact with the flame of the equipment, thus leading to potential opacity and particulate matter problems. This is especially of concern in PM-10 nonattainment areas. This exemption applies only to noncommercial cooking and to food service establishments, such as restaurants and cafeterias. The exemption does not apply to manufacturing facilities.

Fuel burning equipment: The design rate cutoff for fuel burning equipment has been raised from 750,000 BTU/hour to 5 MMBTU/hour. The fuel use is still restricted to gas, and does not include oil or coal, since the latter two fuels may result in significant sulfur dioxide emissions. Fuel burning equipment which uses gaseous fuel and which is used solely for building heat is exempt if the design rate is below 10 MMBTU/hour. The Commission has determined that the emissions from the exempted unit, based on EPA AP-42 emission factors, are negligible.

Chemical storage areas where chemicals are stored in closed containers...: This exemption only applies to the storage of chemicals at qualifying facilities. The exemption does not include facilities where chemicals are loaded into or out of, or transferred between, storage containers. Bulk storage tanks would not qualify for this exemption, since often the material is loaded and unloaded, and such tanks have vents from which emissions occur due to breathing losses. See Sections II.D.1.n., ee., uu., ddd. and fff. for storage tank exemptions.

The Commission will require APENs only for pollutants that are defined as “criteria” pollutants or “reportable non-criteria” pollutants (HAPs, CFCs, SARA 313). Any other pollutants such as carbon dioxide, methane, nitrogen, oxygen, do not require APEN submittals.

Aerosol Can Usage: There may be instances where a source may exclusively use large amounts of aerosol cans, or may use large amounts in addition to other processes. The Commission expects that these instances will be rare. If the Division, a local agency, or others discover such a source, and if the source emits amounts of pollutants, which are believed not to be negligible, such concern can be brought before the Commission as a request to require such source to file APENs and/or obtain a permit. (See discussion under “Adding and Deleting Exemptions,” below)

Odorous emission sources: This exemption only applies to odor emissions, and not to any other emissions of criteria or non-criteria pollutants, which may be associated with the odor. This exemption does not absolve any source from the requirements of Regulation Number 2 (regarding odor limits). If a source emits any pollutant that is above an APEN de minimis level, the source must file an APEN, regardless of odor.

Portable 5 mm btu/hour engines: One party requested that these sources be exempt from APEN and permit requirements. The Commission has determined that sufficient evidence is not available to indicate that emissions from these sources have a negligible impact on air quality in Colorado, therefore they are not exempt until such evidence is forthcoming.

Laboratory equipment and pilot plants: The subcommittee for these rule revisions held extensive discussions regarding exemptions for laboratory equipment and pilot plant activities. More work is needed to define these activities, determine if the emissions are negligible, and if such activities should be exempt from APENS, permits, or both. The Commission recommends that subcommittee discussion of this issue continue, and that it be addressed when Regulation Number 3 is revised to include the Title V operating permit rules (currently scheduled to occur in July of 1993).

Adding and Deleting Exemptions

The Commission has delegated authority to the Division for adding source categories and activities to the APEN and permit exemption lists. If any person believes that a source category or activity should be removed from the exemption lists, because it is discovered that emissions have an impact on air quality or health that is not negligible, such person may at any time go before the Commission to request that such source category or activity be required to file APENs and/or obtain permits.

Oil and Gas Exploration Activities

Oil and gas exploration activities are activities for which it is difficult for the owner or operator to estimate what emission equipment will be required, and therefore what emissions will occur, until the exploration activities are already underway, and near completion. For this reason, the Commission has extended a temporary exemption from APEN and permit requirements for such activities. Before commencing exploration activities, the source must notify the Division. In this way, the Division is aware of the activities and will be able to address any concerns that are raised by the public. Once an owner or operator has determined that an oil or gas well will be produced, and has filed well completion information, the owner or operator must file an APEN and a permit application within 30 days of that completion filing. The permit application must indicate what regulations are applicable to the source, and how compliance will occur, until the construction permit is issued. This helps the source and the Division to ensure that air pollution regulations are being met. If the well will not be produced, the source must notify the Division so that the Division does not expend resources following up on unproduced wells.

APEN Reporting Deferrals for Source Categories

Due to ongoing studies aimed at quantifying their emissions of non-criteria pollutants, the Commission has deferred APEN reporting requirements for five source categories until six (6) months after the studies have been completed or December 31, 1994, whichever is earlier. The categories are industrial boilers, municipal wastewater treatment plants, publicly owned water treatment plants, municipal power generators of less than ten (10) megawatts, which operate for 250 hours or less per year, and natural gas glycol dehydration units. The EPA is conducting studies regarding the first four categories. The oil and gas industry is conducting studies to quantify emissions from dehydration units. This study is currently underway and is expected to be completed in the near future.

In addition, sources which are not undergoing study, but which believe sufficient information is not available for estimating their non-criteria pollutant emissions, may petition the Division for deferral of those emissions until sufficient information is available.

HAP Permit Requirements

Of the 363 non-criteria pollutants/compounds, 330 are defined as hazardous air pollutants (HAPs). Sources emitting HAPs are required to obtain permits if they are subject to Colorado MACT or GACT or the Federal Title III or Title V provisions.

Synthetic Minor HAP Sources

Some parties to the hearing requested that sources which emit HAPs be allowed to avoid future Maximum Achievable Control Technology (MACT) and operating permit requirements by obtaining "synthetic minor" permits. These permits would contain federally enforceable limits, which would keep emissions below the levels, which trigger the MACT and operating permit requirements. The Colorado Act appears to restrict synthetic minor permits to criteria pollutants only. The subcommittee recommended that this issue be deferred to the HAP subcommittee, which will meet in the near future to address Colorado MACT and other HAP issues. Synthetic minor permits for HAP sources are therefore not addressed in this revision.

Permit Transfer of Ownership

The party to which a permit is issued, whose name is included on the permit, is legally responsible for ensuring that all conditions and terms in the permit are met. The permit must contain the correct legal name, reflecting the correct responsible party, in case an enforcement action needs to be taken. In some cases, the legal name of a company may change, while no modifications are made to the equipment. In such cases, the source need only file a single APEN indicating the change. In all cases, the Division must have on file an application and APEN form with the correct name of the responsible party, and including the signature of the person legally responsible for the information.

Permit Requirements - De Minimis Levels

Permit de minimis levels for criteria pollutants have been increased. Levels differ based on the attainment status of the area. As for the APEN de minimis levels, the nonattainment area levels are triggered by any pollutant, not just the nonattainment pollutants.

Language, which would have set permit levels for the Grand Junction area lower than the levels for attainment areas, was not adopted. See discussion above under APEN de minimis levels.

Emissions are compared against the de minimis levels by adding emissions from all sources at the facility that are required to file and APEN. In some cases, a source may initially be below the de minimis levels, but as new units are added to the facility, the de minimis level is eventually exceeded. At such time that addition of new units causes the permit de minimis level to be exceeded, the source must file a permit application for all units at the facility.

Permit de minimis levels for sources of HAPs will be set at the time that the MACT or GACT for that source category is determined.

Permit Requirements - Exemption List

A few new source categories have been added to the permit exemption list. As for APENs, the source category exemptions override the de minimis levels.

Domestic wastewater treatment works: This exemption applies only to treatment facilities which handle wastewater strictly from domestic homes, or wastewater that is similar in nature. It does not include facilities that treat wastewater from municipalities or other sources. The facility may be publicly or privately owned. Wastewater other than domestic wastewater, including municipal wastewater, may contain contaminants from industry and other sources which would result in emissions which are much more significant than the emissions from domestic wastewater.

Fuel burning equipment: Fuel burning equipment with a design rate less than 10 MMBTU/hour, using natural gas as a fuel, are exempt from permit requirements because this is the rate at which the New Source Performance Standard for small boilers is applicable (Regulation Number 6).

Surface Mining Activities: 70,000 tons per year is the production rate at which the Mine Land Reclamation Bureau exempts mining operations from MLRB permit requirements. Oftentimes, these small operations are only temporary, in order to provide material for highway construction projects. The source has often ceased operation before an Air Pollution Control inspector can visit the source to determine compliance. Crushers, screens and other processing equipment are not exempt because these activities may be subject to specific air quality emission limit regulations.

Applicable Requirements Override APEN and Permit Exemptions

To ensure that sources comply with all applicable air quality regulations, an APEN or permit exemption may not be used if taking the exemption would allow a source to avoid any air quality regulation requirements. This provision applies to the source category exemptions and to the de minimis level exemptions. For example, a source may not claim that it is exempt from permit requirements because it has numerous sources, which are below a de minimis level, if the potential emissions from those sources would exceed the PSD major source limit of 100 or 250 tons per year. In such a case, the source would be required to apply for a PSD permit, or must obtain a permit to limit its potential to emit. In order to limit potential to emit, the permit must contain federally enforceable conditions, which limit the physical or operational capacity of the source so that emissions are below the 100 or 250 ton per year level.

Sources, which are subject only to the opacity or general fuel burning and manufacturing requirements of Regulation Number 1, may take any applicable exemption. Likewise, sources, which are subject to the general RACT requirements (but not the specific RACT requirements) of Regulation Number 7, and sources, which are subject to the current Regulation Number 8 provisions, may take any applicable exemptions (i.e., they are exempt if their emissions are below de minimis levels). RACT for sources that would qualify for the APEN exemptions is usually “no control.”

Similarly, sources which are subject only to Regulation Number 1 opacity, general fuel burning, and general manufacturing requirements are exempt from permit requirements. Sources which are subject to Regulation 7, but which must adopt only work practice standards, are exempt from permit requirements if their emissions fall below the de minimis level (two tons per year of VOC). Sources, which are subject to State-only requirements of Regulation Number 8, are exempt from permit requirements.

Regulation Number 1, 7 and 8 sources, which take APEN or permit exemptions must still meet the regulation requirements, even though an APEN or permit is not required. The provisions that would apply to these sources are straightforward and can therefore be easily enforced by the Commission through the regulation, without requiring a permit.

Public Notice Requirements

The criteria pollutant emission level at which a source in an attainment area must go to public notice has been increased from 25 to 50 tons per year (except for lead). In nonattainment areas, the level remains at 25 tons per year. Lead sources are required to go to public notice when the emissions exceed 200 pounds per year. The Commission has determined that raising these levels will not impact the number of public comments the Division receives. Any source requiring a permit for HAPs is required to go to public notice.

Note that Section I IV.C.3 provides that the Division may require any source to be subject to public comment, if it is determined that such source warrants public comment. The EPA requires that all sources subject to PSD or NSR go to public comment. In addition, in order to make limits on potential to emit federally enforceable, permits containing such limits must go to public notice. At this time, the Commission will use this Section to ensure the EPA requirements are met. Language will be added to clarify these requirements when the next revision to Regulation Number 3 occurs (currently scheduled to occur in July of 1993).

**I.L. Adopted July 15, 1993**

**Revisions to Regulation Number 3**

This Statement of Basis, Specific Statutory Authority and Purpose complies with the requirements of the Administrative Procedure Act, C.R.S. 1973, Section 24-4-103(4) for adopted or modified regulations.

Basis

The 1990 Amendments to the Federal Clean Air Act requires states to implement an operating permit program. This program is applicable to certain sources, and requires the sources to obtain detailed permits, which are to be renewed every five years.

Failure of a state to implement an operating permit program will result in EPA sanctions, such as loss of highway funds and increased offset requirements for sources wishing to locate in Colorado nonattainment areas. In addition, the EPA may implement the operating permit program if a state fails to implement a program.

The existing construction permit program will continue to exist, however changes have been made to the program so that the two permit programs (construction and operating) compliment each other.

Specific Authority

The specific authority for this regulation is contained in the Colorado Air Quality Control Act, 1992 as amended. Section 25-7-105(1)(A)(I) requires the Commission to adopt into the State Implementation Plan all requirements of the federal act. Sections 25-7-105(12) provide authority to implement the operating permit provisions of Title V of the Federal Act. Section 25-7-105.1 sets forth federal enforceability provisions. Section 25-7-106(6) provides authority for monitoring, recordkeeping and reporting requirements, Section 25-7- 109.3 provides authority for regulating hazardous air pollutants (HAPs). Section 25-7-111 provides authority for the Division to administer regulations adopted by the Commission. Section 25-7-114.1 provides authority for requiring APENS, and for allowing exemptions from the requirement. Sections 25-7-114.2 through 114.5 set forth construction and operating permit requirements, and application and public participation requirements. Commission action in promulgating these revisions is taken pursuant to Sections 25-7-105 to -109 and 25- 7-114, C.R.S., as amended.

Purpose

NOTE: Subcommittee documents, which discuss the issues and decisions regarding this regulation in detail, and provide fact sheets for various provisions, are available at the Division and Commission offices.

I. Operating Permit Program:

A. Who is subject to the Operating Permit Program?

1. Definition of Air Pollutant

Sources with potential to emit* 100 tons per year of any air pollutant must obtain an operating permit (these sources are referred to as 'major sources"). For purposes of the operating permit program, air pollutant means any pollutant for which an ambient air quality standard has been set (and their precursors), any pollutant which is regulated under the New Source Performance Standard regulations (NSPS, Regulation Number 6), any Class I or Class II ozone depleting compound, and any hazardous air pollutant (all HAPs listed in either the Federal or Colorado Acts).

The Commission has determined that it is not appropriate to use the Colorado Act definition of air pollutant for operating permit purposes. The Act defines air pollutant as being any substance emitted to the ambient air, except for water vapor. Since many substances occur naturally in ambient air, and others will never be subject to any air regulations, operating permits are not needed for emissions of such pollutants.

Major sources of any air pollutant as defined for operating permit purposes must obtain an operating permit, even if no specific standard has been set for the particular air pollutant (see further discussion under "regulated pollutant," below).

2. Major HAP Sources

Sources, which have potential to emit 10 tons per year or more of a single HAP or 25 tons per year or more of a combination of HAPs, are considered" major sources," and must obtain an operating permit, even if no standard for the HAP has yet been set.

Major sources of Colorado HAPs must obtain an operating permit. Permit conditions related to Colorado HAPs will be treated as state only conditions (see further discussion below).

*See definition of potential to emit, Part A of this regulation. Potential emissions are calculated assuming the source operates continuously, at full design rate, using no pollution control equipment. See additional information and details in subcommittee papers (Group D, Synthetic Minors Issue Paper and Fact Sheet).

3. Fugitive Emissions

Fugitive emissions must be included when determining if a source is major for HAPS. Fugitive emissions must be included when using the 100-ton per year threshold (to determine if the source is major) if the source is listed, or if the source and pollutant is subject to any NSPS or Title III regulation.

Fugitive emissions must be included as required for the Prevention of Significant Deterioration (PSD) and nonattainment new source review (NSR) programs.

The Commission has not included language, which exempts fugitive dust sources from the major source definitions at this time. Further investigation is occurring regarding HAP emissions from such sources, and discussions with EPA will continue to determine how to treat such sources. Once these activities are completed, the Commission will consider this issue.

4. Applicability Determinations

Sources are ultimately responsible for determining if they are subject to operating permit requirements. The Small Business Assistance Program is available to assist small businesses in understanding the requirements, in determining applicability, and in complying with the requirements. No "applicability determinations" are available for other sources. The Division must recover the cost of implementing the operating permit program. Time spent reviewing informal requests for applicability determinations would not be recovered. Sources who believe they are subject to the operating permit program should file an application. During the sixty-day completeness determination, if the Division discovers that the source is not subject to the operating permit requirements, the source will be notified. In addition, if the source has obtained a construction permit, it will most likely have been determined then if an operating permit is required. Also, preapplication meetings with the Division are available to sources. All time spent by the Division in reviewing applications will be charged to the source.

5. Synthetic Minor Sources

Existing sources are subject to the operating permit requirements. Some existing sources may want to obtain federally enforceable limits on their production rates or hours of operation, or emission limits in order to avoid the operating permit requirements (known as synthetic minor sources because such limits are needed to make them minor). Construction permits can be obtained to keep emissions below the major source thresholds. Some existing sources do not have construction permits. Others may have construction permits, which do not currently limit emissions below the major source thresholds. Sources may avoid the operating permit requirements by obtaining an emission-limiting construction permit before they are required to apply for operating permits. Sources must obtain a synthetic minor construction permit before the November 1994 due date, or before one year after EPA program approval, whichever applies (see discussion below). If a synthetic minor permit is not obtained before the applicable date, an operating permit application must be submitted.

The Division will review all existing construction permits over a period of time as resources allow, to determine if the existing permits are federally enforceable. In the interim, the Division will assume that all previously issued construction permits are federally enforceable.

New sources may likewise obtain synthetic minor construction permits before they construct in order to avoid the operating permit requirements. All synthetic minor permits must go to public notice in order to be federally enforceable (see discussion below).

"Once in always in" does not apply to the operating permit program (however it does apply to the PSD program). If a major source has an operating permit and reduces its emissions below major source levels, the source may apply for a synthetic minor permit in order to cease being subject to operating permit requirements.

6. Minor Source Exemption

The EPA allows states to give minor sources subject to existing New Source Performance Standards (NSPS) a five-year deferral from the operating permit requirements. Within five years of the approval of any State program, the EPA will determine if the deferral should be extended further, or if some or all minor sources should be permanently exempt from operating permit requirements. If the EPA first approves any State program in November of 1994, this means that minor sources may be exempt until November of 1999. The EPA will decide if minor sources subject to new MACT or GACT (Maximum or Generally Available Control Technology) standards and NSPS should be exempt on a case-by-case basis as the new rules are promulgated.

The Commission has exempted existing minor NSPS sources from the operating permit program at this time. New NSPS and MACT standards will be adopted by the Commission as EPA promulgates them, and at such time, the Commission shall determine operating permit applicability.

7. Voluntary Operating Permits

Any source which is not required to obtain an operating permit (minor sources) can request an operating permit, if desired. An operating permit allows minor sources to obtain the operational flexibility and permit shield provisions allowed in the operating permit program (note, however, that most of the operational flexibility provisions are available under the construction permit program, see discussion under construction permit program Section). The operating permit will replace the source's construction permit. A construction permit is a SIP requirement, and conditions in the construction permit are federally enforceable (except for state only conditions). All conditions in the operating permit must therefore be federally enforceable. Operating permits, which are issued to sources voluntarily applying, will be subject to all of the operating permit procedural requirements (public notice, EPA review, etc.).

B. When is operating permit applications due?

1. Existing Sources

The federal act allows states to phase in processing of existing source applications over a three-year period. One third of the applications must be acted upon within each year after EPA approves the state's program. The program will be submitted to the EPA by November 15, 1993. The EPA has one year to approve the program, therefore the Division must begin processing applications beginning November 15, 1994.

The Commission has directed the Division to divide the existing sources into thirds. One third of the existing sources must submit their operating permit applications by November 15, 1994. The Division will use the new APEN information to identify the first third, and will notify the first third by November 15, 1993. The first third will consist of the least complex sources. The least complex sources should find it easier to prepare their operating permit applications, and the Division should find it easier to process these applications first. The Division will be able to identify any problems with the review procedures, etc. during the first year.

NOTE: The Division cannot issue an operating permit until the EPA has approved the program and is thus ready to begin receiving permits for review. The Division will therefore "hold" applications processed during the first year until the EPA is ready to accept them for review. Once EPA has reviewed and approved the permits, the permits can be issued.

The remaining existing source applications will be due one year after the EPA approves the state's program. The Division will provide notice of the EPA approval date and sources are responsible for submitting their applications on time.

The Division must determine if each application is complete within 60 days of receipt. This may not be possible during the three-year phase in, as many applications will be received at once. The Division will make its best effort to make the completeness determination for all permits within 60 days. If the Division fails to do this, the application shield applies, and the Division cannot enforce against the source for failure to have a complete application on file. The Federal rule provides, however, that the Division has the authority to ask for additional information at any time during the process, and to set a reasonable date by which the information must be submitted. If the source fails to submit the additional information by the due date, the application shield no longer applies. The Commission is confident that under these provisions sources and the Division can effectively work together to ensure that applications are processed in a timely fashion.

2. New Sources and Relationship to the Construction Permit Program

New sources that wish to locate in Colorado must obtain a construction permit, or a combined construction/operating permit before commencing construction. The source may choose to obtain a construction permit or a combined permit.

Sources that choose to obtain a construction permit must apply for a construction permit according to the provisions of Part B of this regulation. Once a construction permit is obtained, the source can commence construction and begin operating. Within 180 days of commencing operation the source must undergo a "final approval" inspection to demonstrate that all permit conditions are being met. Within 12 months of commencing operation, the source must apply for its operating permit. Once a complete operating permit application is submitted, the source can continue to operate under its construction permit until it receives its operating permit.

Sources that choose to obtain a combined construction/operating permit must apply for such permit before commencing construction. The application for a combined permit must contain all of the required information for an operating permit. The Division will issue the permit, which will essentially be an operating permit. The source can then commence construction and operation. Within 180 days of commencing operation, the source must demonstrate compliance with all permit conditions (this 180 day requirement will be a permit condition, and the appropriate hourly processing fee will be charged for the associated inspection). The source continues to operate under its operating permit and no further action is required until permit renewal.

The procedures for obtaining construction permits are not as intense as those required to obtain an operating permit. More extensive public and EPA participation is required in the operating permit process. In addition, more information and requirements must be incorporated into an operating permit than into a construction permit. Nevertheless, it may be advantageous for sources to combine the processing of these two types of permits in order to avoid duplication of effort.

The advantage of a combined permit is that an additional application step is avoided. Sources should note, however, that an operating permit application requires more specific information regarding compliance monitoring, recordkeeping, etc., than a construction permit application. Sources that choose to obtain an operating permit before construction must be able to supply all of the required information for a complete operating permit application.

Sources that choose to obtain an operating permit before construction will be subject to the operating permit timeframes for processing instead of the shorter construction permit timeframes. Construction permit applications can take up to 90, 135, or 365 days, depending on type and size of source. Operating permit applications can take up to 540 days. Construction permits require public notice and opportunity for comment only for sources emitting more than 25 or 50 tons/year of any criteria pollutant, and requires opportunity for public hearing for Prevention of Significant Deterioration (PSD) sources only. The operating permit program requires public notice and opportunity for hearing for all sources. If the programs are not combined, a source may have to undergo public notice twice, once under each process. PSD sources may have to undergo public hearings twice. The EPA only reviews certain applications and draft permits under the construction permit program, and usually does so during the public comment period. The EPA is allowed 45 days to review draft operating permits near the end of the process, and then the Division has 90 days to revise the permit, if necessary.

Sources should consider carefully their confidence in their ability to operate as expected or planned after construction before choosing to obtain a combined permit.

3. Application Shield

Once a source has submitted a complete operating permit application the source is protected from enforcement action for operating without an operating permit, and can continue to operate until the operating permit is issued.

Sources that submit an application for a combined permit may not construct the source until they receive their combined permit.

C. What must be addressed in operating permit applications and permits?

1. Configuration and Grouping of Sources

Total emissions at an entire site (including fugitive emissions at listed and HAP sources) must be considered to determine if a source is subject to the operating permit requirements. Once a source is subject, however, the owner or operator may choose how many operating permits to obtain for the source. A single permit may be issued for the entire source, or individual permits may be issued for individual units, buildings, processes, etc. For example, research and development activities may be permitted separately from the rest of a facility, in order to take full advantage of the operational flexibility provisions for constantly changing research and development activities. In addition, portions of a source could be covered under general permits. See discussions below under operational flexibility and general permits.

The configuration for operating permits may, but is not required to, conform to the way in which a source chooses to file APENS. For example, a source may file separate APENs for all of the units at its facility, but a single operating permit can be obtained. Similarly, a source may file grouped APENs for similar units at its facility, and the operating permit could contain a general statement that the types of units exist at the facility, and could then state what the applicable requirement and associated monitoring, recordkeeping and reporting requirements are for that group of sources. The permit does not have to list the requirements separately, and the monitoring, recordkeeping and reporting requirements can be tailored to meet the needs of the source and the Division for that group of sources. SPECIFIC EXAMPLE: Numerous degreasers are located throughout a facility, which is located in the ozone nonattainment area (metro-Denver). A grouped APEN is filed for all of the degreasers. Since Regulation Number 7 applies to the degreasers, they must be addressed in the operating permit. The operating permit choices are: 1) obtain an operating permit for the degreasers only, separate from the rest of the facility; 2) obtain a single permit for the whole facility, and include a general statement/applicable requirement condition as described above for the degreasers; 3) obtain more than one operating permit for the facility, placing the degreasers in whatever permit(s) the owner or operator chooses. The Commission believes substantial flexibility is available for issuing operating permits that the source can most efficiently deal with, while still meeting the Clean Air Act requirements.

2. “Regulated Pollutants”

Once subject to operating permit requirements, a major source must include all applicable requirements and emission units in their application and must address each “regulated pollutant” associated with the source (except for insignificant activities, see below).

The definition of regulated pollutant is to be used strictly for determining what must be addressed in an operating permit once a source is required to obtain the permit. The definition of regulated pollutant has nothing to do with the definition of major source. (See discussion above, regarding the definition of air pollutant).

Pollutants to be addressed in the application include each pollutant for which an ambient standard has been set (and precursors to such standards, such as volatile organic compounds), ozone depleting chemicals (CFCs), any pollutant subject to a standard under regulation Number 6, and any pollutant subject to a standard under the HAPs requirements (including Colorado HAPs).

"Regulated HAPs"

Note that a HAP must be subject to a standard before the applicant is required to address it in the permit application. Once the EPA adopts a MACT standard for a particular HAP, all sources, even those not subject to the particular MACT standard, and even those not in the source category, must address that HAP in applications. In cases where the Commission or Division determines MACT on a case-by-case basis because the EPA has not, the HAP becomes regulated only for the particular source subject to the case-by-case standard. Once the EPA promulgates the list of 112(r) (accidental release) pollutants, those pollutants will be considered to be "regulated" for all sources.

Fees

The definition of regulated pollutant contained in Part A of this regulation is not used for fee purposes. The Colorado Act specifically sets forth which pollutants are to be assessed fees, and the fee pollutants are set forth in Section VI of Part A. A pollutant does not need to be subject to a standard before the Commission can assess fees.

3. Insignificant Activities

Once subject to operating permit requirements, a major source must include all applicable requirements and emission units in their application and must address each "regulated pollutant" associated with the source except for activities, which the Commission has determined are "insignificant." This regulation sets forth to what extent each activity or piece of equipment at a facility needs to be fully described and included in an operating permit.

The Commission has tailored the insignificant list after the Air Pollution Emission Notice (APEN) and construction permit exemptions, to promote consistency and reduce confusion. The lists are repeated in Part C of the regulation, for convenience. The activities and sources listed in the APEN and construction permit exemption Sections are considered to be insignificant activities, with two exceptions. The lower APEN emission de minimis levels are used instead of the higher construction permit de minimis levels for insignificant activity purposes. Since the permit de minimis levels apply to the facility, the Commission does not believe it is appropriate to use the permit levels. The APEN 5 MMBTU per hour boiler design rate is controlling, rather than the higher 10 MMBTU per hour permit boiler exemption. All boilers with design rates greater than 5 MMBTU per hour must be addressed in the application and operating permit.

Exemptions based on emissions, size or production rate must still be listed in the permit. Enough information must be submitted in the application just to identify the equipment as qualifying for an exemption. An asterisk appears next to each activity listed in Part C, which must be listed in the application.

Applications do not have to list activities that are exempted based on category.

Applications cannot omit information needed to determine the applicability of, or to impose any applicable requirements on a source. In addition, the exemptions cannot interfere with fee determinations. Since the mechanism used to assess fees is the APEN and not operating permits, this should not pose a problem for purposes of insignificant activities.

The Commission has added APEN exemptions for research and development and laboratory activities. The exemptions apply to small research and development facilities, and to lab activities that the Commission has determined have a negligible impact on air quality in Colorado. Owners and operators of research and development facilities that are subject to APEN reporting are expected to report emissions from samples received from clients for evaluation, but only to the extent, the information is available. The Commission believes that facilities that accept material for evaluation should have some responsibility and knowledge regarding what is being accepted.

Research and development facilities may continually change the types of projects under investigation, therefore the control efficiency of equipment may not always be known. The Commission has determined that research and development facilities may base APEN reporting thresholds on actual instead of uncontrolled actual emissions. In addition, since owners and operators of such facilities do not always know in advance what projects will be undertaken, the Commission has allowed such sources to report emissions after the fact, in annual APEN updates to the inventory.

Research and development activities are prime candidates for the types of operational flexibility allowed in this regulation (see discussion below). The Commission encourages research and development activities to use the operational flexibility provisions.

Some of the activities were described in the Statement of Basis and Purpose for the Commission's May 1993 Regulation Number 3 hearing. Parties to this hearing have asked for clarification regarding some of the provisions.

The emission levels for triggering APEN reporting requirements are based on uncontrolled actual emissions. The Commission recognizes that in some cases, “uncontrolled” emissions are not easily defined. For example, the uncontrolled emissions from a degreaser may be subject to interpretation. The emissions from this type of operation depend on how often it is used and how fast objects are cleaned in the unit. Uncontrolled emissions could possibly mean that a person is standing at the degreaser using the machine continually, and as rapidly as is humanly possible. The Commission recognizes that calculation of emissions for this and similar operations involves some judgment, and will take into consideration reasonable assumptions used in determining uncontrolled emissions.

The exemption for land development (less than 25 acres in size and 6 months in duration) applies to all land clearing activities, such as preparation of land for housing development, or preparation of land for oil and gas activities to occur.

As stated above, insignificant activity exemptions cannot be used if it, would result in an applicable requirements being avoided. The EPA requires all applicable requirements to be addressed in operating permits. Similarly, APEN and construction permit exemptions cannot be taken if an applicable requirement would be avoided. The Commission has given certain sources an exemption from the applicable requirement provisions, for APEN and construction permit purposes. For example, a source that is subject to Regulation Number 7, but not to a specific source category requirement of regulation Number 7 (i.e. the source is subject only to a case by case RACT determination), may take the APEN exemption based on the 1 ton per year de minimis level. The Commission has determined that RACT for such small sources is usually no control. For construction permits, a source may take an exemption if it is subject solely to a work practice standard of Regulation Number 7. For example, degreasers used in the ozone nonattainment area (metro-Denver) are subject to a specific Section of Regulation Number 7, which requires covers and proper operation. Degreasers in the nonattainment area are subject to a specific Section of the regulation, therefore they must file APENs, however since the Section only requires work practice standards, no permit is required if the emissions are below the permit de minimis levels. It should be noted that since an applicable requirement exists, the degreaser and associated work practices must be addressed in the operating permit. Degreasers in the rest of the State are exempt from APEN and permit requirements if they are below the de minimis levels. Note that the EPA is required to set Maximum Achievable Control Technology (MACT) limits for degreasers in 1994. When the Commission adopts the MACT standards for degreasers, all degreasers subject to the MACT standard will be required to file APENs and obtain permits.

4. Inapplicability Determinations

Operating permits must list all applicable requirements and must state how continuous compliance with the requirements will be demonstrated. The source is provided with protection from enforcement as long as each permit condition and compliance requirement is met (known as the permit shield). The source may wish to obtain enforcement protection for regulations, which do not apply. In such cases, the application must identify which regulations do not apply to the source. These regulations will then be identified in the permit, and the permit shield will apply.

This protects the source in the event that a mistake is made and the regulation really does apply to the source. The source is protected from enforcement action until the permit can be reopened and the correct requirements inserted.

5. Application Form and Checklist

Operating permit applications must contain a lot of complex information, including identification of all applicable (and inapplicable, if the permit shield is to apply) requirements. This can be a daunting task for the applicant. The Commission has directed the Division to develop checklists for use by the applicant. One checklist will identify all data that must be included in an application. Another checklist will identify all air regulations. The applicant can use the latter checklist to identify which regulations apply to their source, and which don't.

The State must submit an application form to the EPA along with the operating permit regulations. The Commission has directed the Division to develop an application form, taking into account suggestions and comments from the public.

6. SIP Equivalency

The Commission has determined that it is appropriate to allow sources to set forth procedures in their permit that will show that a SIP limit is being met through methods that are equivalent to, but do not exactly follow, procedures set forth in the SIP.

For example, suppose a source is required to meet a volatile organic (VOC) compound limit by using a coating that does not contain more than a certain amount of VOC. The source could propose to meet the limit by some other means than using such a coating. Their application would set forth quantifiable, replicable, accountable procedures that would show that they could still meet the limit even though they would not be using the required coatings. Such procedure could consist of using control equipment, or using a combination of complying and non-complying coatings for which the average emissions would meet the VOC limit. Monitoring, recordkeeping and reporting procedures would be set forth in the permit. The procedures must be sufficient to show continuous compliance with the underlying applicable requirement.

This procedure allows sources to show compliance through alternative methods without having to go through the Commission and the EPA for a case-by-case SIP revision. The EPA would review the process during its 45-day review period. The public would have opportunity for comment and hearing.

NOTE: This procedure overrides the requirement in Regulation Number 7, which states that all such alternatives will undergo a case-by-case SIP revision.

7. 112(r) (Accidental Release) Requirements

Operating permits must address any requirements established under Title III (hazardous air pollutants) of the Federal Act, except that the accidental release plans required under Section 112(r) do not have to be incorporated into the permit. The permit must merely state that the source is required to submit a plan to the appropriate entity. The Commission can take enforcement action against a source for failure to submit a plan. Enforcement action cannot be taken for failure of the source to meet any of the requirements contained in the plan.

8. Compliance Monitoring

Operating permits must contain monitoring sufficient to demonstrate compliance with the applicable requirements. Methods and procedures may be set forth in the applicable requirements. If methods and procedures in the applicable requirement are insufficient to demonstrate compliance, the operating permit must “fill the gap” by specifying appropriate methods. Compliance methods may be as simple as recordkeeping, or may require continuous monitoring equipment. The source must state in their application how they will demonstrate compliance. The Division reviews this proposal and agrees with it or recommends something else. The Common Provisions provides the Division with the authority to require monitors. The Division has used, and will continue to use, best engineering judgment to determine when monitors are necessary and feasible. The Commission has determined that in some instances it may be appropriate to require continuous emission monitors, even in cases where the applicable requirement does not specify monitors, and that sufficient opportunity for discussion and appeal are available to the source, therefore monitors can be required even if the applicable requirement does not specifically require monitors.

The EPA is in process of developing and promulgating their enhanced monitoring rules. These rules may speak specifically to continuous monitoring. The Commission will take into account this new rule and determine if the operating permit monitoring requirements should be revisited once the EPA rule is promulgated.

By January 1994, the EPA will publish a list of existing rules, which do not contain sufficient monitoring, or recordkeeping methods, and will develop criteria that could be used to determine what is sufficient. After the rules are identified, the EPA will proceed to revise the rules to make them sufficient. The need for "gap filling" will then decrease.

9. Compliance Certifications

Each operating permit application must be accompanied by a "compliance certification" indicating that all information presented is true and accurate. The certification must be signed by a "responsible official," usually a CEO, of the company. Likewise, compliance certifications must be submitted every six months, indicating the compliance status of the source. Such certifications must also be signed by the responsible official. The burden is on the source owner or operator to ensure that all permit conditions are addressed in the certification, and all information is complete and correct.

The Commission's definition of "responsible official" allows delegation of responsible official authority to plant managers under certain conditions, including prior approval from the Division.

10. Recordkeeping and Reports

The operating permit must contain all recordkeeping necessary to ensure compliance with the applicable requirements. The Federal Act requires such data to be maintained for five years. The Commission has determined that sources need not keep a full five years of data on site for inspection review. Instead, sources are required to make immediately available to the Commission or Division data for the past year, along with the compliance certifications for the past five years. The actual data for the remaining four years must be provided to the Commission or Division within 48 hours of request.

Monitoring data must be reported at least every six months.

The Commission will allow sources flexibility in determining what records are appropriate, and in determining the schedule for reporting, in order to allow coordination with other reporting requirements (such as Community Right To Know, etc.). Such flexibility is allowed provided the requirements of the Clean Air Act are met.

Malfunctions and emergencies - The Commission has adopted the Federal provisions for emergency and malfunction protection, except that sources are required to provide oral notice within two hours of the next working day, and written notice with one month after the emergency occurs. Past experience indicates that sources will most likely not be able to meet the EPA's recommended two-day written notice.

The Commission does not include continuous monitor malfunctions in the emergency provisions. The emergency provisions serve to provide an absolute defense if an applicable requirement is violated. Since the Commission cannot tell if a source is in or out of compliance with an applicable requirement when monitors malfunction, it is not appropriate to include monitor malfunctions in the emergency provisions. Monitor malfunctions which would violate provisions which set specific operating conditions and specifications for the monitor, however, could be granted the emergency protection for those specific performance conditions, if such malfunctions were due to unforeseen circumstances and reported as set forth in the emergency provisions. The Commission has determined that extra protection for monitor malfunctions is not warranted, as procedures and specifications for monitors include performance requirements which take into account the inherent operational fluctuations and abilities of the monitors.

Sources must report any exceedances of standards, which are not due to malfunctions or emergencies “promptly.” The Commission has determined that including such deviations in the six-month monitoring report is sufficient. This will not impair the Division or Commission's authority to assess penalties regarding the deviation.

Public Availability of Reports: Copies of all reports and compliance certifications will be made available at the local health departments. As always, such information is available at the Division offices.

11. State-Only Conditions

Certain Commission regulations are not part of the State Implementation Plan, and therefore are not federally enforceable. The Commission has given sources the option of including state only conditions in operating permits, or of maintaining such conditions in a separate construction permit. This option is available for all state-only conditions except those pertaining to major Colorado HAP sources. Major Colorado HAP sources are required by statute to obtain an operating permit. “State-only” conditions will be listed separately from federal conditions in operating permit. (Sources that are major for federal HAPs must obtain an operating permit, and provisions pertaining to the federal HAPs are federal, not state conditions.)

Since the operating permit is meant to be used as an all-encompassing document for sources and the Division, the source may want to refer to only one document to determine what needs to be done to remain in compliance. If the conditions are included in an operating permit, the source may choose whether or not to have the permit shield, operational flexibility, and other operating permit allowances and requirements apply to the conditions.

State-only conditions do not have to undergo the same procedural requirements as other operating permit conditions. Affected state and EPA review is not required.

Currently, the following regulations are state-only requirements: odor Regulation Number 2, municipal waste combustor Regulation Number 6, Part B. Future Colorado MACT/GACT standards will be state-only requirements.

12. Confidentiality

Applicants are allowed to classify certain information as being confidential in terms of product or processes. In no case may emission information be kept confidential, and in no case may compliance certifications be kept confidential.

Records and reports may be kept confidential, however, instances where this will be allowed will most likely be rare, since emissions data or information related to emissions data may not be kept confidential.

The current confidentiality provisions and procedures remain in effect, however the Commission has directed the Division to examine the provisions and procedures and to recommend improvements.

D. How Long Does It Take To Obtain the Permit?

1. Completeness Review

The Division has sixty days from receipt of an application to determine if all information necessary to process the application is included. If the application is incomplete, the Division must notify the source and request the additional information. Additional information must be submitted by the applicant within a reasonable amount of time. Once a complete application is received, the Division must act on the application within 18 months. The Division must analyze the application, prepare the permit, and ensure that all of the procedural steps as set out below are met. Once all requirements are met, the Division will send the source its fee letter, and will not issue the permit until all applicable processing fees are paid. The fee letter must be sent within 18 months of receipt of a complete application.

2. Public Notice and Hearing

Once the Division analyzes the application and prepares a draft permit, the permit and application must undergo a thirty-day public notice. If a hearing is requested during the public notice, thirty-day notice of the hearing must be provided, and the hearing must occur within sixty days of the notice.

The Commission has provided an opportunity for sources to respond to any public comments received. This source response in no way affects the Division's time constraints for issuing the permit, nor does it affect the permit, which the Division ultimately issues.

3. Affected State Review

During the public notice, a copy of the draft permit will also be sent to any affected, nearby states, for their review.

4. EPA Review

Once public notice and hearing are completed, the Division will make any necessary revisions to the draft permit, and will submit a proposed permit to the EPA for their review. The EPA has 45 days to review the permit. The Division then has up to 90 days to make any necessary revisions to the permit to address EPA concerns, before the permit can be issued.

5. Copies of Application

The applicant must provide a sufficient number of copies of the application for submittal to the EPA, affected states and public notice, including copies for County Commissioners.

E. Renewals

1. Renewal Application Content

Operating permits must be renewed every five years. Renewal applications must undergo all of the review procedures (public notice, EPA review) as the initial operating permit.

Applicants may incorporate by reference any previous application material or permits for portions of the operation which will not change from the initial application. The renewal application may only address operations which will change and which will require new permit terms or conditions. Copies of all material incorporated by reference must be included with the renewal application. All material must be provided for public comment, affected state review, and EPA review.

2. Renewal Application Due Date

The federal rule states that permitting authorities should be able to process "90%" of renewal applications within six months. The federal rule does not mandate that states process renewals within six months. The rule gives states flexibility to require applications for renewals, and specifically states that other times may be approved, which are necessary to issue the permit before it lapses. The application can be due as soon as 18 months before expiration, and as late as six months. Renewed permits must be issued before the old permit expires.

As described above, the public comment, hearing notice, hearing, EPA review, and revision periods required in the Federal rule take up 220 days, or approximately seven and a half months. The time allotted for these activities is fixed in the Acts and rules (except for the time allowed for States to revise draft permits, based on EPA review). The amount of time for actual review of the application itself varies depending upon the type of application. A breakdown of the allotted times follows:

| | |
|---|---|
| Public Notice: | 30 days |
| Hearing: | 60 days |
| EPA Review: | 45 days |
| Division Response: | 90 days |
| TOTAL | 220 days |

Two hundred and twenty (220) days is the minimum required. No time is allotted for revising the permit between each step as necessary, nor for transmitting the permit from one step to the next. The 220 days is required for public notice and EPA review only, it does not include any time for the Division to actually review the application and draft a permit.

Sources are allowed to seek judicial review if a permit is not issued in time. This could potentially result in wasted Division and court resources dealing with an impossible situation. In addition, the EPA may determine that the program is not adequate if the Division continually fails to issue renewed permits before expiration. Finally, if permits are not issued in time, the EPA can revoke and reissue permits, or can terminate the permits, in which case the source's right to operate ceases.

Given that the notice and review procedures alone take 220 days, and the allowed flexibility, and the requirement that renewed permits be issued before expiration, the Commission has determined that it is not reasonable to allow renewal applications to be submitted as late as six months before expiration. Nine months may be adequate if hearings are not requested for such renewals, however, no one can predict how many applications will or will not require public hearing. It would not make sense to accept applications only six or nine months before expiration, knowing that if a hearing is requested, the new permit will not be issued before expiration. The twelve months will give the Division sufficient time to review the application, and in addition, will give the source some time to ensure that they have submitted a complete application before the permit expires. Sources are allowed to update their applications up to the time a draft permit is issued for public notice. This will allow sources a chance to address any last minute market considerations or changes in their application.

The Division will send written notice of the need to apply for a permit renewal to permittees six months prior to the date a renewal application is due. This notice is to aid permittees, and the failure of the Division to provide notice to any individual permittee is not contended to be used as a defense for the failure to apply for a permit renewal.

As sources and the Division gain experience with the new operating permit program, the Commission and the Division will determine if the timeframe for renewals can be shortened. The first renewals will not be due until the year 2000.

F. Reopenings

Operating permits must be “reopened” during the term of the permit if new regulations become applicable to the source, if a mistake is found in the permit, or if additional measures need to be incorporated to ensure compliance with applicable requirements. A permit is reopened to address only the new requirement or correction, not to address the entire permit. The Division must give the source 30 days notice before reopening the permit. Reopenings must undergo all of the same procedures and requirements as the original permit (notice, EPA review, etc.). The Commission will allow sources the option to reopen an entire permit instead of just the necessary portion. This would require, however, that a source be able to submit a complete application for renewal within 30 days of notice, so that the Division can meet the 18-month deadline.

G. Modifications

States must adopt expeditious procedures for processing changes that require a modification to a permit.

1. Administrative Modifications

   Administrative modifications are *minor changes to the permit, such as change in owner, more stringent monitoring requirements, or correction of typographical errors. The change at the source can be made upon submittal, and the Division must revise the permit within 60 days. No public notice or EPA review is required. The original expiration date does not change when administrative modifications are made.

2. Minor Modifications

   The existing construction permit program requires sources to obtain construction permits before they construct or modify. Revisions to construction permits are required before any changes at the source are made. In contrast, the Federal rule allows changes to be made without revisions to the operating permit, provided no SIP requirements are violated. Sources are allowed to make "minor modifications" upon notice to the Division. The source must supply a draft permit, which is submitted for affected state and EPA review. The permit is revised within 90 days. No public notice is required at the time the modification is made. The Commission was faced with a dilemma. Since the construction permit program is a SIP requirement, sources would not be allowed to make minor modifications without first obtaining a construction permit. This in effect would negate the operational flexibility envisioned in the Federal Act.

   Only certain modifications at the source may qualify as "minor modifications" for operating permit purposes. The change cannot be a "Title 1" modification. Title I contains requirements applicable to new sources. Title I revisions include the following changes:

   1. Modification that triggers Prevention of Significant Deterioration and New Source Review (significant net emission increase)

      The significant levels (defined in Part A of this regulation) are based on the potential to emit of a source or modification. Since no construction permit is in place to limit the potential to emit of a minor modification, all minor modifications will be triggered based on potential emissions, not actual emissions.

   2. Modification which triggers New Source Performance Standards (NSPS) (Any change that increases the amount of any air pollutant) - This definition only applies to specific NSPS sources, unless it is referenced in an applicable requirement

   3. Modification that triggers Section 112 (hazardous pollutants). EPA will be adopting "de minimis" levels that will trigger a modification.

   Minor modifications cannot involve any significant change or relaxation in monitoring, recordkeeping, or reporting requirements. Minor modifications also cannot violate any permit condition, which the source has voluntarily obtained in order to limit potential emissions for avoidance of requirements (such as PSD requirements).

The EPA expressed their concern regarding the construction permit SIP requirements and minor modifications. The Commission has determined that it is appropriate to submit a SIP revision for the construction permit program, in order to allow sources the flexibility allowed under minor modifications. The Commission will allow minor modifications under the operating permit procedure, and changes before obtaining a permit, however all substantial requirements needed for a construction permit must be met. These requirements include ambient modeling to assess the modification's impact on air quality in Colorado, as required in the SIP. As under the current construction permit program, minor modification procedures cannot be used to circumvent PSD or NSR requirements by making individual changes, which together would otherwise trigger PSD or NSR. The enforcement protection of the permit shield does not apply to these modifications. Sources should be confident that all applicable requirements would be met before submitting a change as a minor modification. If the source errs in its determination, the Division, the Commission, and the EPA can take enforcement action against the source and the source's right to operate under the modification is terminated (the source must revert back to the permit as it existed before the modification was requested).

Upon permit renewal, the minor modification undergoes public notice along with the rest of the permit, and the permit shield can be extended to the minor modification provisions.

3. Significant Modifications

Significant modifications are changes at the source which are not administrative modifications, and which do not qualify as minor modifications. Such changes trigger PSD or NSPS, etc., or involve significant changes in or relaxation of monitoring, recordkeeping and reporting requirements. A revised permit must be obtained before the source is allowed to commence construction for the change.

A source may choose to obtain a revision to its operating permit, or it may choose to obtain a construction permit before making the change. Significant modifications to operating permits must undergo all of the public notice and EPA review requirements, therefore a source should plan on submitting its application well in advance of making the change. If a construction permit is obtained first, the source should apply at least three to four and a half months in advance (except for PSD sources, which should plan 12 months in advance). Once the construction permit is obtained, the source may commence construction. The conditions of the construction permit do not need to be incorporated into the operating permit until renewal, unless more than three years remains in the term of the operating permit, in which case the operating permit must be reopened, and the significant modification provisions incorporated.

H. Operational Flexibility

The Federal rule requires a State's program to include operational flexibility provisions, which allow a source to make certain changes without having to obtain a modification to their operating permit. The changes are simply incorporated into the operating permit when it is renewed. The types of operational flexibility are described briefly below. Subcommittee papers and fact sheets, which explain the provisions in more detail, and give specific examples, are available at the Division and Commission offices. The Commission has directed the Division to devise simplified explanations of all of the provisions.

"502(b)(10)" Changes (named after a Section of the Federal Act): A source is allowed to make a change, which would violate an express permit term, provided no applicable requirements are violated. The source can make the change after a seven-day advance notice to the Division. The permit shield does not apply. The Commission will allow sources to revert back to the original permit term, provided seven-day notice is given to the Division. The permit shield can then apply again to the provision, which is contained in the permit.

Permit Caps: A source may ask for an upper limit in total facility emissions. Changes may occur within the facility, as long as the upper limit is not exceeded, and all applicable requirements are met. The permit shield applies to these changes. Seven-day notice is required before the change is made. This type of operational flexibility may be suitable for research and development facilities.

Alternative Scenarios: The source can identify various operational scenarios in its application, along with the applicable requirements and compliance demonstrations. The source can then switch from one scenario to another without notification to the Division. The permit shield applies to these changes.

Emission Trading Based on the Permit: The applicant can request that the trading provisions (for netting out) provided for in Part A of this regulation be incorporated into their operating permit. As long as all of the provisions are met, the source can use the provisions to make changes without notification to the Division.

Off Permit Changes: These changes can be made at the source with seven-day notice to the Division. The changes involve activities that are not addressed in the operating permit. The same qualifications as those for minor modifications apply to these changes (cannot be Title I modifications, significant monitoring changes, etc.) Note that the same SIP concerns apply to these changes that are discussed above under minor modifications. A construction permit would be required before these changes could be made. The Commission has decided to submit a SIP revision to allow these changes.

Emission trading based on the SIP: This is the only federally allowed operational flexibility provision that the Commission did not adopt. This provision would allow sources to use the emission trading provisions of Part A without specifically stating the procedures in the permit. The Commission does not currently have an approved SIP that would allow this, therefore the EPA would not approve this procedure at this time. The EPA is expected to develop guidelines for approvable SIPs within two years. The Commission will consider this provision once it is apparent what the EPA would approve.

I. General Permits

General permits are standard permits that apply to specific source categories. The sources in the category have similar applicable requirements and similar monitoring, recordkeeping and reporting requirements. The general permit will include criteria by which a source may qualify for the permit. Sources that are out of compliance may not qualify for a general permit, since a separate individual compliance plan would be required. The general permit undergoes one-time public notice and hearing and EPA review when it is initially developed. Qualifying sources can use standard, simplified applications and obtain the general permit without having to go through the entire application process (public notice and hearing) individually. A list of all sources that have been issued a general permit shall be maintained by the Division and made available upon request.

The general permit (as originally developed) undergoes five-year renewal, including public notice and EPA review.

General permits will also be developed for the construction permit program, and will usually be identical to the general operating permit for that source category. Existing sources that have not obtained a general construction permit through the construction permit program (probably because a general permit did not exist at the time a construction permit was obtained) may operate under the general operating permit within 60 days of submitting a complete application for the permit, which corresponds with the amount of time allowed for a completeness determination. The application shield becomes effective upon submission of a complete application. The Division will issue the general permit to the source upon completion of the analysis. The permit shield becomes effective upon issuance of the operating permit.

Sources which receive a general construction permit through the construction permit program may operate under the general permit as an operating permit 60 days after a complete operating permit application is submitted, provided the required compliance demonstration has been performed in the required time (180 days). Such source must apply for the operating permit within 12 months of commencing operation. Once such application is received and determined to be complete, the Division will issue a certification, which states that the construction permit now becomes the operating permit.

General permits will ideally be useful for minor sources that will be subject to operating permits at a later date. Minor sources are more likely to be subject to similar applicable requirements. The Commission has directed the Division to devote resources as they become available to identification of sources that would be suitable for general permits and to the development of general permits. Candidates for general operating permits include sources that become subject to new MACT/GACT standards (i.e. dry cleaners), or existing and new NSPS sources (i.e. asphalt plants).

The Commission will allow major sources to have general permits as part of their overall operating permit. As general permits are developed, major sources may use them. The source would just reference in their initial or renewal application that they have a general permit. General permits, however, cannot be issued to major sources if the issuance of the general permit would cause a violation of any of the applicable requirements in any other operating permits they have, or if issuance of a general permit would trigger a Title I or Title III modification. The Commission will allow general permits to be used for an entire major source only in those instances where the use of general permits is appropriate (homogenous, straight-forward sources).

J. Title III (Hazardous Air Pollutant Requirements)

The provisions of Title III must be implemented through the operating permit program. As discussed above, all major sources of HAPs must obtain an operating permit. As the Commission adopts MACT standards, the permit must be reopened to include the new requirements.

As the EPA promulgates new MACT standards, they will decide if minor sources as well as major sources affected by the standard must obtain operating permits.

Once the EPA approves the State's operating permit program, the Division and Commission must begin making case by case MACT determinations for new major sources and modifications, if the EPA has not yet set a MACT standard for that category. The EPA will be setting emission levels at which modifications are triggered.

Once the EPA approves the State's operating permit program, if the EPA fails to meet its mandated deadline for setting a particular MACT standard, the State must determine MACT for that source category within 18 months. Permits will be reopened to incorporate the State MACT standard. Once the EPA determines MACT for the category, permits may need to be reopened again, and sources may need to retrofit their units, depending upon the difference between the State and EPA MACT determinations.

K. Title IV (Acid Rain Provisions)

The Commission is required, and fully intends, to adopt the acid precipitation rules and requirements as promulgated by the EPA, and to implement the requirements through the Title V permits, as also required under the Federal Act.

Title IV sources (power plants) are required to submit the Title IV portion of their operating permits by January 1, 1996. The permits must be issued by December 31, 1997. The EPA is planning on having all of the requirements and forms finalized so that Title IV sources can apply for Title IV requirements at the same time they apply for their initial operating permit. This could help avoid re-opening of the permit. To facilitate this, the Commission has determined that Title IV sources should be included in the last group of existing sources required to apply for operating permits (due one year after EPA approves the program, see discussion above).

The Commission also intends to adopt provisions related to the WEPCO rule promulgated by the EPA, which deals with Clean Coal Technology Projects and other modifications at utilities. The rule is currently slated for the spring of 1994 in the Commission's regulatory agenda. In the interim, the Commission and Division will continue the existing policy of treating such projects as allowed by the EPA. Also, the Commission wishes to encourage Clean Coal Technology Projects, which are used to develop and identify better methods of controlling and preventing air pollution. The Commission has directed the Division to consider research and development factors, and the importance of developing new technologies, if enforcement action may be necessary due to violations related to such projects.

II. Construction Permit Program

A. Synthetic Minors

As discussed above, construction permits are the vehicles through which sources can obtain federally enforceable limits on their emissions in order to avoid the operating permit requirements. In some cases, sources may also choose to obtain limits to avoid PSD or NSR requirements. Such synthetic minor permits must undergo public notice in order to be federally enforceable.

B. SIP Equivalency

The Commission has determined that it is appropriate to allow construction permit sources to use the SIP equivalency procedure that is provided for operating permits in the Federal Act. Current regulations, such as Regulation Number 7, require a case-by-case SIP revision for equivalent procedures, which involves public notice, a mandatory Commission hearing, and EPA approval. The new SIP equivalency provisions override Regulation Number 7 provisions. All SIP equivalency proposals require public notice, opportunity for hearing (but not mandated if not requested), and EPA review. The Commission will require such construction permits to follow the PSD track, which requires public notice and an opportunity for public hearing. The EPA will review the proposal during the public comment period.

C. Minor Modifications and Operational Flexibility

The Commission has extended most of the operational flexibility provisions directly to the construction permit program, since no modification to a permit is required. These provisions include Administrative Modifications, Alternative Scenarios, Emission Trading Based on the Permit, and Permit Caps.

The remaining operational flexibility provisions, and the minor modification provisions are not available through the construction permit program, however sources may obtain these additional allowances by voluntarily applying for an operating permit.

D. General Permits

The Commission has determined that the general permit process will be allowed only for the operating permit program. The general application and permit forms, however, should be used for construction permits as they are developed. The Colorado Act requires new sources to obtain a construction permit before commencing construction, therefore the source must have their construction permit in hand before constructing. In addition, Regulation Number 3 requires certain sources to undergo public notice before construction. The Commission believes that notice should continue to be provided to the public where appropriate, before a source constructs near them.

As discussed above under general operating permits, the Division will identify candidates for general construction permits as resources are available. The same sources identified in the discussion above are candidates for general construction permits. In addition, general permits may be suitable for sources wishing to obtain synthetic minor status, such as emergency and backup generators.

III. Emission Fees

Though it was not noticed for this hearing, some parties indicated they had concerns regarding the Division's policies for charging annual emission fees. A request was made to include the Division's policy in the regulation. The Commission believes the Division should be given the flexibility to determine the most efficient and reasonable procedures and policies for assessing fees, therefore the policy will not be included in the regulation. The Division will prepare a written policy for public distribution on the methods it will use to calculate and collect emission fees.

IV. Where Can a Source Go For Assistance In Understanding the New Requirements?

A. Small Business Assistance Program

Even though existing minor sources (small businesses) are exempt from the operating permit program, small businesses will need help understanding the construction permit program requirements. In addition small businesses need to understand the operational flexibility requirements, and need to understand if it would be advantageous for them to apply for an operating permit. The EPA may decide that some minor sources should be required to apply for operating permits as new MACT and NSPS standards are promulgated.

Last September, the Commission approved a plan for developing a Small Business Assistance Program. The program is under development and is expected to be implemented and fully operational by November of 1994. In the interim, Division staff is available to answer any questions, which a small business may have regarding air quality regulations and requirements.

Some information has already been developed regarding APEN requirements and simplified calculation procedures.

B. Pre-application Meetings

This regulation provides opportunity for any source to request a preapplication meeting with the Division, to discuss what requirements may be applicable to a source.

C. Division Staff

Division staff will remain available to all sources and the public, to answer questions regarding the operating permit and construction permit programs.

**I.M. Adopted March 17, 1994**

**Revisions to Regulation Number 3 Part A, Section II.E.**

Pursuant to Section 112(n) of the federal Clean Air Act, the US Environmental Protection Agency (EPA) is required to conduct an extensive study to create a reliable estimate of the existence or quantity of hazardous air pollutants (HAPS) emissions from certain sources such as utility and non-utility industrial boilers. Another study under Section 112(n) relates to emissions from publicly owned treatment works (POTWs). Section 112(n) recognizes that technological limitations exist on the ability to reliably estimate these emissions. The required studies are complex and costly, and EPA has indicated that the utility and non-utility boiler study will not be concluded until the end of 1995. The original time frame contemplated by Congress anticipated that the study would be completed by November 15, 1993. Unlike the mandatory boiler study, the Clean Air Act merely authorized EPA to study POTW emissions and EPA has decided not to continue with the study. Thus, the emissions information that was originally expected will not be developed in time to facilitate APEN reporting by December 1994. Since the emissions from facilities that treat municipal-type wastewater are virtually identical to those from POTWs, the lack of POTW emissions data also affects this category of sources as well.

During rulemaking in 1993, a deferral for HAP reporting from boilers and other listed sources was granted until six months from the date federal studies are complete or until December 31, 1994. This deferral appears in Part A, Section II.E.

This was based in large part on the recognition that it would be unreasonable and infeasible to expect these sources to attempt to duplicate the EPA studies and to provide meaningful data earlier than EPA. The postponement was not intended to forgo reporting obligations (it applied to emissions points and processes only, not to entire facilities), but rather, to recognize technical limitations and to await (not duplicate) the results of the EPA studies. The Statement of Basis, Specific Statutory Authority and Purpose for the 1993 rulemaking session explained, “Due to ongoing studies aimed at quantifying their emissions of non-criteria pollutants, the Commission has deferred APEN reporting requirements for five source categories until six (6) months after the studies have been completed or December 31, 1994, whichever is earlier.”

It is now apparent that neither the EPA boiler study nor the POTW study will be timely completed for effective implementation of ' II.E. The clear intent of the regulation is to postpone report of HAP emissions by sources such as utility and non-utility industrial boilers, POTWs and municipal-type wastewater treatment works, pending the results of the ongoing EPA studies. The rationale for this intention is that it is technologically infeasible for these sources to comply with this reporting requirement without the results and utilization of the EPA studies. The original intent and rationale for a postponement continue to pertain at this time and provide the basis for this rulemaking.

Additionally, highly costly tests would be required if reporting is required prior to the results of the EPA studies. There is a serious question about the accuracy of any reporting prior to the conclusions of the EPA studies. Moreover, if sources attempt to formulate tests, inconsistencies with testing procedures, resulting data and interpretation thereof would result, thereby further complicating issues for impacted sources and administration by the state. It is believed that using the EPA studies results will allow avoidance of such costs and result in more accurate APENS, which, in turn, will facilitate easier administration by the state.

During the Commission's prior deliberations on this matter, the Commission expressed intent to revisit this December 31, 1994 deadline if the EPA studies would not be timely completed. Impacted sources must be placed on notice as early as possible concerning any deadline because lead-time to conduct studies and extensive planning would be necessary. This rulemaking postpones to December 31, 1995, or six (6) months after the EPA studies are complete, whichever are earlier, for utility and non-utility industrial boilers, and POTWs and municipal-type wastewater treatment plants. This decision furthers the Commission's original intent concerning the underlying reporting. This issue may be revisited in the future if the information expected to be derived from the EPA studies continue to be delayed.

The specific authority for this regulation is contained in the Colorado Air Pollution Prevention and Control Act, 1992 as amended. The Legislative Declaration, ' 25-7-102, recognizes that an accurate emission inventory is needed to adequately manage air resources in Colorado. Section 25-7-109.3 provides authority for regulating HAPs. Section 25-7-114.1 provides authority for requiring APENS, and for allowing exemptions from the requirements. Section 25-7-109(4) requires the Commission to promulgate regulations pertaining to HAPs.

**I.N. Adopted May 19, 1994**

**Findings Regarding the Basis for the Emergency Rule Revisions to Regulation Number 3, Concerning the Operating Permit Program**

The Air Quality Control Commission held this emergency rulemaking hearing on May 19, 1994, after such notice of rulemaking as practical, to postpone the November 15, 1994 deadline for submission of operating permit applications by those existing major stationary sources previously notified by the Division to submit applications by that deadline. The revisions to Regulation Number 3 would phase-in the required submission of operating permit applications by these sources over a three-month period beginning January 1, 1995. The Commission finds that the immediate adoption of this emergency regulation is imperatively necessary for the preservation of the public welfare and to ensure compliance with the federal law, and that compliance wit normal notice requirements for rulemaking would be contrary to the public interest.

This emergency regulation is necessary for three reasons. First, the Environmental Protection Agency (EPA) has issued a formal letter to the State of Colorado advising the State that its Title V operating permit program submission, contained in the Commission's Regulation Number 3, must be revised in order to obtain federal approval of the State operating permit program in accordance with the mandates of the federal Clean Air Act. The earliest date by which the Commission is able, pursuant to law, to promulgate such revisions and make them effective is September 30, 1994. Sources that are subject to the operating permit application deadline of November 15, 1994 will not have sufficient time to complete their applications and submit them by that time after the promulgation of the revisions.

Secondly, and more importantly, it was not until the 1994 Colorado legislative session that the legislature appropriated money for the necessary FTE's at the Division to process operating permit applications and to implement the program. The money will not be available for the Division's use until July 1994, and given the shortcomings of the State personnel system, the new Division employees will not, in all likelihood, begin their employment until on or around November 1, 1994. If the Commission did not act on an emergency basis to postpone the application deadline of November 15, 1994, persons subject to the application deadline will be required to apply to the Division prior to its ability to fully train the new employees or to provide sources any services necessary under the mandates of the federal Clean Air Act. This imposes an unnecessary burden on sources, as well as the Division.

Finally, the federal Clean Air Act requires that the State have sufficient money to cover the direct and indirect costs of implementing the Title V program. These costs include those necessary for the Division to review permit applications and issue permits within certain established timeframes, as well as to perform inspections and other compliance monitoring actions. The EPA has indicated to the State, in a letter dated April 8, 1994, that if the State does not have sufficient money to cover these costs, the EPA cannot grant any type of approval, including interim program approval. In this event, EPA must take over the Title V program in Colorado, and has threatened to impose sanctions on the State. Therefore, the Commission must act on an emergency basis to postpone the operating permit application deadline in order to give sources sufficient advance notice of the changed deadline and in order to ensure that the Division will be able to review and process those applications within the timeframes set forth in the federal Clean Air act.

In light of the evidence presented at the emergency hearing on the difficulty and cost to sources of completing operating permit applications, given the short timeframe between the Commission's ability to revise and make effective changes to Regulation Number 3 required by the EPA and the current deadline; on the difficulty and cost of evaluating operating permit applications filed with the Division and of the Division's inability to perform services required by the current Regulation Number 3 and deadline of November 15, 1994; and on the EPA's letter evidencing its concern that the Division will not be sufficiently financed to perform those federally-mandated services, the Commission finds that an emergency exists which warrants the passage of this emergency regulation. The Commission does not believe that this emergency regulation represents any risk to public health.

**I.O. Adopted August 18, 1994**

**Revisions to Regulation Number 3**

This Statement of Basis, Specific Statutory Authority, and Purpose comply with the requirements of the Administrative Procedures Act, Section 24-4-103(4), C.R.S. (1994) for adopted or modified regulations.

Basis

The 1990 Amendments to the Federal Clean Air Act require states to implement an operating permit program. Failure of a state to implement the operating permit program will result in EPA sanctions.

On July 15, 1993, the Air Quality Control Commission adopted revisions to Regulation Number 3 necessary to implement the State's operating permit program. The Commission also adopted revisions to Regulation Number 3 that were necessary to integrate the operating permit program with the existing construction permit program, and that were necessary to extend certain provisions of the operating permit program to minor sources not otherwise subject to the program.

On November 5, 1993, the Governor submitted Colorado's operating permit program to the Region VIII, Environmental Protection Agency (EPA) for its approval. The EPA reviewed Colorado's submittal and on April 8, 1994 responded to the State's submittal, noting certain deficiencies in the program. These deficiencies must be corrected and the revisions submitted to the EPA no later than October 1, 1994. The Commission promulgated these revisions to Regulation Number 3 in response to EPA's comments. EPA also noted certain legislative changes that are required in order for the State of Colorado to obtain full approval of its operating permit program. Therefore, at this time, the Commission contemplates that the State will receive interim approval of the operating permit program; within 18 months after receiving the interim approval from EPA, the State must submit legislation that will satisfy all of the federal requirements.

The EPA in its April 8 letter required the Commission to revise in certain respects the Statement of Basis, Specific Statutory Authority, and Purpose for Revisions to Regulation Number 3 that was dated July 15, 1993 and which was submitted to the EPA on November 5, 1993. The required revisions are reflected in this Statement of Basis, dated August 18, 1994.

Specific Authority

The specific authority for this regulation and its revisions is contained in the Colorado Air Quality Control Act, 25-7-101, et seq. (1989 & 1994 Supp.). Section 25-7- 105(l)(A)(1) requires the Commission to adopt into the State Implementation Plan all requirements of the federal act. Sections 25-7-105(12) provide authority to implement the operating permit provisions of Title V of the federal act. Section 25-7-105.1 sets forth the federal enforceability provisions. Section 25-7-106(6) provides authority for monitoring, recordkeeping and reporting requirements. Section 25-7-114.1 provides authority for APEN requirements and for allowing exemptions from the requirements. Section 25-7-114.2 through 114.5 set forth construction and operating permit requirements, and application and public participation requirements. Commission action in promulgating these revisions is taken pursuant to Sections 25-7-105 to 109 and 25-7-114.

Statement of Basis and Purposes of Changes to Regulation

1. In Part A, I.B.9.e., the definition of “applicable requirement” concerning enhanced monitoring was changed to comply with the federal definition, incorporating all monitoring and enhanced monitoring requirements established pursuant to Sections 504(b) and 114(a)(3) of the federal act.

2. In Part A, I.B.22., the definition of “federally enforceable” was amended to mirror the definition found in Section 25-7-105.1 of the Colorado Air Pollution Prevention and Control Act.

3. In Part A, I.B.35.D.e., the Commission exempted any modifications that are not “major modifications” from the definition of Title I modifications, for sources with operating permits that utilize the minor permit modification procedures set forth in Part C, Section X.A. This is because EPA cannot allow the minor permit modification procedures to be used for Title I modifications; therefore, for the minor permit modification procedures to have any use at all, this change was necessary. All modifications must still comply with the requirements of 40 CFR Part 51.165, as reflected in Regulation Number 3, Part B, IV.D.1.a.-h. In effect, this change merely allows an operating permit source to modify without going through the procedural requirements of obtaining a construction permit, but still requires the source to meet all substantive requirements.

4. Part C, X.A.5., XII.A.1 and XII.B. were revised to reflect the change described in paragraph Number 3 above.

5. Part A, I.B.62, a definition of “state-only condition” was added. This term is used throughout Regulation Number 3.

6. In Part A, Section II.D.1.aaa. (APEN exemptions), and in Part C, Section II.E.3.aaa. (insignificant activities for operating permits), the Commission exempted storage of lubricating oils from notice and permit requirements. Because new source performance standards apply to storage tanks of capacity > 40,000 gallons, the Commission revised these provisions to ensure that the exemptions would not allow a source to avoid new source performance standards.

7. In Part A, II.D.5., the Commission established an administrative procedure whereby the Division could process and grant requests for exemptions from permit and APEN requirements. However, this amounted to a SIP revision without allowing EPA the opportunity to review and approve the revisions. Therefore, the Commission amended this procedure to require that the Commission adopt the exemptions pursuant to rulemaking, on an annual basis, and submit the revisions to EPA prior to a source being able to take the exemptions.

8. Part A, IV.B. contains operational flexibility provisions concerning “trading based on the permit.” The federal rule allows a source to take advantage of any EPA-approved emissions trading program, without the need for a SIP revision. At this time, Colorado does not have an EPA-approved generic emissions trading program. To obtain EPA approval of the State's operating permit program, the Commission amended this provision to clarify that the trading based on the permit may be utilized only if the SIP contains an EPA approved trading program.

9. At Part B, III.A.6., the Commission clarified that the provisions of IV.D.1.a.-h. must be met in order for the source to utilize the minor permit modification procedures. Previously, the Commission had merely cross-referenced Section IV.D.1., which contained time periods for review that conflicted with the minor permit modification procedures.

10. At Part B, IV.D.1.i. and in Part C, V.C.1.c., the Commission had provided authority for a source to use an alternative emissions limitation that is as stringent as an applicable requirement so long as the permit contained provisions to ensure that the limitation is quantifiable, accountable, enforceable and based on replicable procedures. The preamble to the operating permit rule, 40 CFR Part 70 makes clear that it is the SIP, not the permit that must contain these replicable procedures. Therefore, in Part C, the Commission amended V.C.1.c. to clarify that the alternative emissions limitation may be taken only if it is allowed by the SIP; then in Part B, IV.D.1.i., the Commission removed the alternative emissions limitation language because the SIP must itself contain the replicable procedures. EPA is expected to have guidance in the near future on alternative emissions limitation.

11. In Part C, III.B.7., the Commission clarified that a source applying for a combined construction/operating permit must first obtain the permit prior to commencing construction.

12. In Part C, III.C.12., the Commission clarified that ambient air quality standard considerations in issuing permits apply only to temporary sources (pursuant to the federal law), and to new and modified sources applying for a combined construction/operating permit (pursuant to state and federal law). Although this was always the case, the provision previously could have been read to allow consideration of these standards in issuing operating permits.

13. In Part C, V.B.3. & 5., the Commission allowed minor sources to voluntarily opt into the operating permit program in order to gain the operational flexibility of operating permits. These minor sources, however, could avoid the public participation, EPA and affected state review provisions. The EPA was concerned that synthetic minor sources would be able to opt into the program, and in so doing would lose their federally enforceable limitation (imposed by the construction permit which would be lost), without going through the required public participation and EPA and affected state review. The Commission revised these provisions to clarify that synthetic minors opting into the program must go through all the necessary reviews. In addition, major sources of Colorado-only HAPs need not go through the public review process attendant to operating permits. The EPA was concerned that the provision could be read to allow federal HAP major sources to avoid public participation and review. The Commission clarified these provisions to ensure that such was not the case.

14. In Part C.III.B., the Commission revised the schedule for submission of operating permit applications by the remaining two-thirds of sources in order to reflect the anticipated interim approval date of the operating permit program of January 1, 1995. This revision would also allow the Division to notify some sources of the need to submit an application before January 1, 1996, but on or after November 15, 1995, upon twelve months' notice.

Changes to the Statement of Basis and Purpose dated July 15, 1993

I.C.2. “Regulated HAPS”

Revise this paragraph to read:

Note that a HAP must be subject to a standard before the applicant is required to address it in the permit application. Once the EPA adopts a MACT standard for a particular HAP, all sources, even those not subject to the particular MACT standard, and even those not in the source category, must address that HAP in applications. In cases where the Commission or Division determines MACT on a case-by-case basis because the EPA has not timely promulgated a MACT standard for a source category or subcategory of sources, the MACT becomes applicable to all sources within that source category, pursuant to 112(g) of the federal act. In cases where the Commission or Division determines MACT on a case-by-case basis for an existing source that modifies prior to promulgation of an applicable MACT standard, the HAP becomes regulated only for a particular source subject to the case-by-case standard, pursuant to 112(g) of the federal act. Once the EPA promulgates the list of 112(r) (accidental release) pollutants, those pollutants will be considered to be “regulated” for all sources.

I.G.2. Minor Modifications

Revise the second paragraph under this heading to read:

Only certain modifications at the source may qualify as “minor modifications” for operating permit purposes. The change cannot constitute a “major modification” as that term is defined in Part A, Section II.B.35.B. The change cannot otherwise be a “Title I” modification. Other Title I requirements are applicable to new sources. These Title revisions include the following changes: (same).

I.H. Operational Flexibility

Emission Trading Based on the Permit: Revise this paragraph to read: The federal rule allows a source to change its operations, using the emissions trading provisions of an EPA-approved SIP to net out and avoid the need to revise its permit. At this time, the emissions trading provisions of Part A, Section V, have not been approved by EPA as generic trading provisions. Therefore, until the Colorado SIP contains a generic emissions trading policy approved by EPA, each emissions trade request will require a case-by-case SIP revision. EPA is intending to provide guidance for an emissions trading program in the near future.

**I.P. Adopted March 16, 1995**

**Revisions to Regulation Number 3 Construction Permit Program**

Background

At the request of the U.S. Environmental Protection Agency, Region 8, the Air Quality Control Commission adopted amendments to Regulation Number 3, Parts A and B, in order to clarify how the provisions relate to each and the federal regulations. These changes were necessary in order to gain federal approval of the State Implementation Plan.

Specific Statutory Authority

The Specific authority for this regulation is found in the Colorado Air Quality Control Act. Section 25-7-105(1) provides that the Commission shall promulgate such rules and regulations as are consistent with the legislative declaration and necessary for the proper implementation and administration of the Colorado Pollution Prevention and Control Act, including a comprehensive state implementation plan which shall meet all requirements of the federal act and shall be revised whenever necessary or appropriate. Section 25-7-109 provides that the Commission shall adopt, promulgate and from time to time modify or repeal emission control regulations that require the use of effective practical air pollution controls. Section 24-4-103 provides the rule making procedure followed during the promulgation of this rule. Section 25-7-110 provides the specific Commission procedures followed during the setting of standards and regulations. Commission action in promulgating these regulations is taken pursuant to the above statutory provisions.

Purpose

Most of the amendments to Regulation Number 3, Parts A and B are of a general housekeeping nature. However, three provisions require greater explanation:

The Division originally proposed adding a definition of “construction” consistent with the federal definition for New Source Review and Prevention of Significant Deterioration. To eliminate the potential for confusion and conflict with the state statutory definition, the Division has removed that provision from the amendments. There is a definition for construction, which applies to Regulation Number 3, Parts A and B, in the General Provisions Regulations; that definition matches the state statutory definition.

The changes to the definition of “Net Emissions Increase” in Part A, Section I.B.37 needs some explanation. In order for an increase or decrease to be creditable, the Division could not have relied on the increase or decrease in issuing a permit under Regulation Number 3. Also, the source has two choices for proving the extent of the emissions increase or decrease: (1) the source submits or has on file an APEN indicating the baseline emissions rate and then submits a revised APEN within one year after making the increase or decrease (the difference between the two APENs is the amount of creditable increase or decrease) or (2) the source provides credible, demonstrable evidence to the Division of actual emission rates both before and after making the increase or decrease (the source can make the before and after demonstration any time during the contemporaneous period).

The general constructions permit provisions of Part B, Section IV.J. were amended to provide greater detail of how the Division would actually implement the provisions. The Division retains the discretion to determine whether it will issue a general construction permit, although a source or group of sources can request that the Division do so. These provisions are meant only for minor sources, including sources wishing to obtain federally enforceable limits on their potential to emit, making them synthetic minors. The contents of a general construction permit will vary depending on the type of source involved. The Division will state in the general construction permit that goes out for public notice all the criteria a source must meet in order to qualify for coverage under the permit, the method of application (including specific application forms if different from a standard construction permit), the deadline for application, and other requirements as necessary and specified in the permit (i.e. monitoring, reporting, and recordkeeping requirements). After receiving an application to be covered by a general construction permit, the Division will determine whether the source fits within the intended coverage of the general construction permit, meets all applicable requirements, and satisfies all the criteria as laid out in the general construction permit. If the Division grants a source the right to construct and operate under a general construction permit, there are still some situations under which the Division may require the source to obtain an individual construction permit (i.e., the source makes changes that bring it out of compliance with the general construction permit or circumstances change such that the source is no longer appropriately controlled under the general construction permit).

Overall, the amendments to Regulation Number 3, Parts A and B are meant to integrate with the existing rules and meet the federal requirements for the State Implementation Plan.

**I.Q. Adopted May 18, 1995**

**Revisions to Regulation Numbers 8 and 3 Synthetic Minor Permit Program**

This Statement of Basis, Specific Statutory Authority, and Purpose comply with the requirements of the Administrative Procedures Act, Section 24-4-103(4), C.R.S. (1994) for adopted or modified regulations.

Background

At the request of the Division, the regulated community and the state legislature (HB94-1264), the Air Quality Control Commission adopted rules that would allow the Division to issue permits to limit a source's potential to emit hazardous air pollutants (HAP). Such a mechanism is necessary and important because it enables the Division to issue a permit to a source of HAP in order to limit the source's potential to emit below emission thresholds requested by the applicant, thus allowing the source to avoid a variety of requirements such as Title V operating permit requirements, Title III maximum achievable control technology (MACT) requirements promulgated by the U.S. Environmental Protection Agency (EPA), or Colorado MACT requirements.

Specific Statutory Authority

The specific authority for these revisions is contained in the Colorado Air Quality Control Act, 25-7-101, et seq. (1989 & 1994 Supp.). Section 25-7-109.3(2) provides the specific authority for the Commission to adopt provisions allowing the Division to create synthetic minor sources of hazardous air pollutants. Section 25-7-109 provides that the Commission shall adopt emission control regulations requiring the use of effective practical air pollution controls. Section 25-7-109.3(2) provides that in order to minimize additional regulatory and compliance costs to the state's economy, any program created by the Commission shall contain a provision, which exempts those sources or categories of sources, which it determines to be of minor significance from the requirements of the program. Section 24-4-103 provides the rule making procedure followed during the promulgation of this rule. Section 25-7-110 provides the specific Commission procedures followed during the setting of standards and regulations. Commission action in promulgating these regulations is taken pursuant to the above statutory provisions.

Purpose

The rulemaking includes the permanent addition of Regulation Number 8, Part E, Section IV and amendments to Regulation Number 3, Part B. Following is a description of the purpose of each Section within Regulation Number 8, Part E, Section IV:

Section A of the rule clarifies that Regulation Number 8, Part E, Section IV applies to sources that choose to voluntarily limit their potential to emit HAP. This Section clarifies that although the Division shall issue permits to qualified applicants, the Division will not include in the permit any indication of the source's exemption status for other requirements (i.e. Title V or Title III of the federal Act) unless the source asks the Division to include all relevant emissions units and pollutants in the permit review. Under this regulation, the applicant chooses which emission units to cover in the particular permit: that can be all HAP emission points, some or one HAP emission points, all criteria pollutant emission points, and/or some or one criteria pollutant emission points. Unless there is a need for a state-only or federally enforceable permit condition, the Division will not impose any additional applicable requirements on criteria pollutants or HAPs for the emission unit or a number of emission units. If the permit applicant wants a thorough review of the facility and a determination by the Division that the facility qualifies as a synthetic minor from Title V and/or Title III, or other specific provisions of the state or federal Act, then the applicant can choose to have a comprehensive Division review in the permit. Sources choose in the permit application the threshold level below which they want to limit the potential to emit hazardous or criteria pollutants. Sources may want to bring their emissions below Title V major source thresholds or may want to limit their emissions below affected source thresholds under specific MACT standards or enhanced monitoring thresholds when those rules are eventually enacted. When a source applies for a permit under Regulation Number 8, the Division uses the procedural provisions of Regulation Number 3 to issue the permit. Finally, this Section clarifies that receiving a permit under this regulation will not relieve a source from possible future EPA requirements that apply to minor or area sources of HAP or state conditions; however, such sources may request a permit to further limit the potential to emit HAP below the trigger threshold.

Section B describes the elements of a permit issued under this regulation. The permit needs to include practically enforceable permit conditions. The Division makes the final determination on what those conditions are on a case-by-case basis for each permit. The monitoring, recordkeeping, and reporting requirements will depend on the specific source, for instance, practical enforceability may require calculating mass balances, installing a continuous emission monitor, keeping track of consumption rates for various materials, etc. However, the permit conditions to limit a source's potential to emit shall be only as stringent as necessary to limit the source's potential to emit the pollutant of concern. For instance, the Division cannot require a source to add control equipment to reduce emissions significantly if the source can adequately reduce emissions without that control equipment. The applicant may consolidate reporting or monitoring requirements from this regulation and Regulation Number 3 for the emissions unit. Finally, if requested by the applicant, the permit may include alternative operating scenarios, approved by the Division. Such alternative operating scenarios shall include specific monitoring, recordkeeping, and reporting methods as needed. However, Section IV.B.4 for alternative operating scenarios is not intended to include modifications that trigger new source review unless such sources go through all the specific requirements of the construction permit program for modifications under new source review.

Section C tells the source what information to turn in to the Division, increasing the efficiency of communications between the source and the Division and streamlining the application process. The application forms will reflect the intent for the Division to be flexible in its approach to permitting these sources. Although the Division would prefer a consistent approach (i.e., all applications filled out fully), the Division recognizes that often these sources will have unique circumstances that cannot be adequately addressed in a standard application form. The Division further intends that the application forms be flexible enough so that sources can choose to have the Division calculate emissions and determine the permit conditions for them.

Section D, the public participation requirements, is a requirement of EPA. This Section makes mandatory what was previously discretionary for the Division.

Section E clarifies that the Division can combine the requirements from this Regulation with those for limiting the potential to emit criteria pollutants under Regulation Number 3 into a single permit so that it is easier for both the Division and the source to keep track of the overall permit requirements. Also, this Section IV of Regulation Number 8 is not intended to restrict the ability of a source to apply for and the Division to issue a construction permit under Regulation Number 3 with limits on the potential to emit criteria or hazardous air pollutants.

Section F explains to the source that if a physical or operational change triggers another requirement, the permit issued under this Section will not relieve the source of the obligation to comply with that requirement.

Section G informs the source that is must comply with the permit conditions at all times, i.e. on an ongoing basis.

Section H serves as an interim mechanism for gaining federal enforceability of the permit and is based on EPA guidance on potential to emit; this Section does not apply once EPA has approved these rules for limiting the potential to emit HAP. In order for a permit to be federally enforceable, EPA must receive a certification of compliance from the source indicating the source will comply with the permit terms. The source should send a copy of the initial permit approval with the certification of compliance to EPA and a copy of the certification to the Division (to keep in the permit file). The responsible official, defined in Regulation Number 3, needs to sign the certification.

The revisions to Regulation Number 3 are necessary to implement the provisions of Regulation Number 8, Part E, Section IV through the construction permit program. Note, that the operating permit program already has the necessary provisions to integrate Regulation Number 8, Part E, Section IV. The amendment to Section III.A.4 is not intended to extend any new rights to the applicant in the event the applicant declines permit conditions set by the Division, this amendment just makes explicit that the permit is strictly voluntary and that a dissatisfied applicant has normal rights of appeal associated with construction permits issued under Regulation Number 3. The addition of Section III.A.7 is to clarify that if a source wants to request a limit on the potential to emit in a standard construction permit, the source may do so. This Section also gives the Division the authority to limit the potential to emit HAP in a construction permit. The amendments to Section IV.C implement the public participation requirements of Regulation Number 8, Part E, Section IV. The requirement that the Division submit a copy of the public notice to EPA for sources applying for a permit to limit the potential to emit criteria pollutants or federal HAP is meant to include criteria pollutants (already required under an agreement between the Division and EPA) and federal HAP listed in Appendix A of Regulation Number 8 (these are the HAP listed by EPA under Section 112(b) of the federal Act). Permits for sources limiting the potential to emit Colorado HAP do not need to be sent to EPA for comment.

Overall, these rules are intended to meld with the existing permit provisions within Regulation Number 3 while providing the added authority for the Division to issue permits to limit the potential to emit hazardous air pollutants and the opportunity for Colorado sources to get out of more rigorous permit requirements.

**I.R. Adopted May 18, 1995**

**Revisions to Regulation Number 3 Part A, Section II.E.2 (As requested by Metro Wastewater Reclamation District)**

This Statement of Basis, Specific Statutory Authority and Purpose for revisions to Regulation Number 3 complies with the requirements of the Administrative Procedures Act, C.R.S. ' 24-4-103(4) for adopted or modified regulations.

Basis

The 1990 Clean Air Act Amendments required states to inventory air emissions. C.R.S. ' 25-7-114.1 contains the requirements for this inventory. The Amendments also authorized EPA to conduct emissions studies for certain source categories, included publicly owned treatment works (POTWs). No adequate, reliable, and economically reasonable emissions estimations methods are currently widely available for these emissions.

Based on the expectation that publication of these studies would result in the creation and dissemination of practical emission estimation techniques, revisions to Regulation Number 3 were promulgated in March of 1994 which postponed reporting of non-criteria reportable pollutants for these sources until July 31, 1995, or until six months after the completion of the national studies, whichever occurred first. The postponement also applied to facilities, which treat municipal-type wastewater, since such facilities' emissions are virtually identical to those from POTWs.

EPA has eliminated funding for the federal POTW study. However, the Association of Metropolitan Sewerage Agencies (AMSA) has been assisting EPA in preparing its guidance document, and AMSA has also been preparing its own guidance. These documents are expected to be useful in estimating POTW air emissions. A final draft of AMSA's report is expected to be issued in the summer of 1995. EPA is also expected to issue its finding of presumptive MACT for POTWs for purposes of the Clean Air Act " 112(j) and (g) at about this time.

Authority

The specific authority for this regulatory amendment is contained in C.R.S. ' 25-7-106(1), which authorizes the Air Quality Control Commission to promulgate such regulations as are necessary or desirable to carry out an effective air quality control program, and ' 25-7-114.1, which authorizes the Commission to promulgate the APEN inventory program.

Purpose

In order to give POTWs and facilities that treat municipal-type wastewater sufficient time to prepare reliable APENs, the Commission has extended the postponement of reporting for non-criteria reportable pollutants for these sources until December 31, 1995. The Commission finds that extending the APEN reporting deadline is in the public interest because the information to be published by EPA and AMSA will not become available to these sources in time to allow for sufficiently reliable APEN reporting.

**I.S. Adopted August 17, 1995**

**Revisions to Regulation Number 3 to Change TSP to PM-10 for PSD Increments and Housekeeping**

This Statement of Basis, Specific Statutory Authority and Purpose complies with the requirements of the Administrative Procedure Act, C.R.S. 1973, Section 24-4-103(4) for adopted or modified regulations.

Basis

On June 3, 1993 the U. S. EPA promulgated changes to the Prevention of Significant Deterioration (PSD) rules replacing the Total Suspended Particulate (TSP) increment with particles with an aerodynamic diameter of less than or equal to a nominal 10 micrometers (PM-10) increments. TSP continues to have a significance level for new sources but no longer influences the PSD increments.

Additionally the Division has identified several mistakes in the publishing of Regulation Number 3.

Specific Authority

The specific authority for this regulation is contained in the Colorado Air Pollution Prevention And Control Act, 1992 as amended. Section 25-7-105 (1) (a) (I) requires the Commission to promulgate a comprehensive state implementation plan that meets all requirements of the federal Clean Air Act. Section 25-7-105(1) (c) requires the Commission to promulgate a prevention of significant deterioration program.

Purpose

The Regulation Number 3 PSD rules implement the Federal PSD rules in Colorado. Under the PSD program areas that are in compliance with the National Ambient Air Quality Standards (NAAQS) are required to adopt a permit program for the preconstruction review of new stationary sources and modifications of existing stationary sources to prevent significant deterioration of existing air quality levels. The implementation of the new PM-10 increments will utilize the existing baseline dates and baseline areas for PM. The PM increments measured, and PM-10 already consumed since the original baseline dates established for TSP will continue to be accounted for, but all future calculations of the amount of increments consumed will be based on PM-10 emissions.

The Division is also proposing some minor housekeeping while revising this regulation. There were several Sections where the language published in the Colorado Register was either repeated or the changed paragraph and the original paragraph were both printed. There was also an outside request that submitted an outdated version of the regulation that was inadvertently published.

**I.T. Adopted December 21, 1995**

**Part A, Sections I.B.37 & 67; Part B, Section IV.D.4**

This Statement of Basis, Specific Statutory Authority and Purpose complies with the requirements of the Colorado Administrative Procedures Act, Section 24-4-103, C.R.S. and the Colorado Air Pollution Prevention and Control Act, Section 25-7-110.5, C.R.S.

Basis

Regulations 3, 7 and the Common Provisions establish lists of Negligibly Reactive Volatile Organic Compounds (NRVOCs). The revisions adopted consolidate the list of NRVOCs into the Common Provisions, assuring that the same list of NRVOCs apply to all the Colorado Regulations. This provides more consistency in those chemicals regulated as VOCs.

Specific Statutory Authority

The Colorado Air Pollution Prevention and Control Act provides the authority for the Colorado Air Quality Control Commission to adopt and modify Regulations pertaining to organic solvents and photochemical substances. Section 25-7-109(2)(f) and 25-7-109(2)(g), C.R.S., grant the Commission the authority to promulgate regulations pertaining to Organic solvents and photochemical substances. The Commission's action is taken pursuant to authority granted and procedures set forth in Sections 25-7-105, 25-7-109, and 25-7-110, C.R.S.

Purpose

Of the EPA list of non-photochemically VOCs), and adopting the EPA definition by reference, a single list of negligibly reactive VOCs will apply uniformly to all These revisions to Regulations Number 3, 7, and the Common Provisions are intended to clarify substances that are negligibly reactive VOCs, which are reflected in the EPA list of non-photochemically reactive VOCs. By consolidating the list (which consists Colorado Air Quality Control Commission Regulations.

This revision will also include EPA's recent addition of acetone to the negligibly reactive VOC list. The addition of acetone to the list of negligibly reactive VOC's provides additional flexibility to sources looking for an alternative to more photochemically reactive VOCs. Because the EPA has added acetone to their list of non-photochemically reactive VOCs many industries, which make and supply products to Colorado industries, are planning to substitute acetone for more reactive VOCs. This change in the content of products purchased by industry for use in Colorado would adversely affect industries in Colorado if acetone remains a regulated VOC in Colorado. By adopting acetone as a negligibly reactive VOC industries will be able to take advantage of and benefit from this possible shift in product contents.

**I.U. Adopted February 15, 1996**

**Revision to Part A, Section II.E.1 APEN Deferral for Utility and Non-Utility Boilers**

This Statement of Basis, Specific Statutory Authority and Purpose complies with the requirements of the Administrative Procedures Act, CRS 1793, Section 24-4-103(4) for adopted or modified regulations.

Basis

The current provisions of Regulation Number 3, Part A, Section II.E.1., were designed to postpone reporting of non criteria reportable pollutants by sources such as utility and non-utility industrial boilers and small municipal generators pending the results of ongoing studies being conducted by EPA pursuant to Section 112(n) of the federal Clean Air Act. EPA was directed by Congress to complete those studies within three years after enactment of the federal act, i.e., by November 15, 1993; however, EPA has yet to do so.

During the Commission's last deliberations on this subject, it was stated that if EPA could not meet its deadline, then the Commission would revisit this deadline. Both the Commission and the regulated community were hopeful that EPA would be able to finish its work by the fall of 1995 so sufficient time was available for utilities to meet the December 31, 1995 deadline.

Specific Authority

Section 25-7-114.1 provides authority to the Commission to identify APEN reporting requirements. There currently are no federal reporting requirements concerning emissions of non-criteria reportable pollutants (NCRPs) or hazardous air pollutants (HAPs) from boilers. The current state regulations exceed federal regulatory requirements with respect to APEN reporting of emissions.

Purpose

A short postponement of the original deadline serves a significant dual purpose and both the state and the regulated community benefit from a deferral in this instance. The postponement avoids forcing an uneconomic and non-beneficial compliance requirement at this time on the regulated community. Since there are no compliance obligations respecting HAP emissions from boilers, either in effect or proposed, EPA and Division interpretations provide that an applicant for a Title V operating permit need only list - not estimate quantities of emission of - an application for an operating permit. This revision is administrative in nature, and is not intended to affect air emissions.

**I.V. Adopted March 21, 1996**

**Revisions to Parts A, B & C for Insignificant Activities (Parties: Air Pollution Control Division, Colorado Association of Commerce & Industry and the Colorado Utilities Coalition for Clean Air Division - Part A, Section I.B.9.a; Section II.D.1.kk, 4.a, b.(iii) & (vi); Part C, II.E.3.kk**

Basis

The Division reviews the addition of any requested insignificant activities to Regulation Number 3 once each year. The additions requested included small remote reservoir degreasers and torch cutting activities. Both of these items were reviewed by EPA Region VIII prior to the hearing date and given verbal approval.

The degreaser exemption provides that degreasers not using any chemicals covered by a Maximum achievable Control Technology (MACT) standard and meeting the definition of small remote reservoir are not required to submit an APEN to the Division. The torch cutting exemption clarifies the status of torch cutting as an exempt activity.

Authority

The specific authority for this regulatory amendment is contained in §25-7-114.1(2), C.R.S., which requires the Commission to exempt those sources or categories of sources, which it determines to be of minor significance from the requirement than an air pollutant emission notice is filed. Section 25-7-114.6(1), C.R.S., requires that the Commission designate those classes of minor or insignificant sources of air pollution which are exempt from the requirement for an emission notice or the payment of an emission notice filing fee because of their negligible impact upon air quality.

Purpose

This rule change provides some clarification and additions to the APEN exemption list for those sources that the Division believes to be of minor significance.

Colorado Association of Commerce and Industry - Part A, Section II.D.1.ttt; Part C, Section II.E.3.nnn.

Basis

The Division reviews the addition of any requested insignificant activities to Regulation Number 3 once each year. The Colorado Association of Commerce and Industry (CACI) requested the addition of emergency power generators with limitations based on the size or hours of operation. The revisions rely on EPA guidance regarding emergency power generators.

Authority

The specific authority for this regulatory amendment is contained in C.R.S §25-7-114.1(2), which requires the Commission to exempt those sources or categories of sources, which it determines to be of minor significance from the requirement that an air pollutant emission notice be filed. C.R.S. §25-7-114.6(1) requires that the Commission designate those classes of minor or insignificant sources of air pollution that are exempt from the requirement for an emission notice or the payment of an emission notice filing fee because of their negligible impact on air quality.

Purpose

This rule change provides an addition to the APEN exemption list and clarification of the insignificant activities list for emergency power generators that are of minor significance base on size and/or hours of operation.

Colorado Utilities Coalition for Clean Air - Part A, Section II.D.1.aaa.(i), (ii); sss.(1).iv to vii; uuu; vvv; www; xxx; yyy; zzz; aaaa.(i), (ii); Part C, II.E.3.aaa.(i), (ii), xxx.(1).iv to vii; yyy; zzz; aaaa; bbbb; cccc; dddd; eeee

This Statement of Basis, Specific Statutory Authority and Purpose complies with the requirements of the Administrative Procedure Act, C.R.S. 1973, Section 24-4-103(4) for adopted or modified regulations.

Basis

The current provisions of Regulation Number 3., Part A and Part C both contain lists of activities and sources considered to be “insignificant” or exempt from reporting requirements. On December 29, 1995, the Commission proposed revisions to its existing Regulation Number 3, Parts A and C. Alternative proposals were submitted by members of the public, and after consultation, were endorsed by the Division.

Specific Authority

Section 25-7-114.1 provides authority to the Commission to identify APEN reporting requirements. Further, the rulemaking authority of the Commission is found in Sections 25-7-105 to 109 CRS, as amended. The regulations of the Commission currently contain lists of activities and sources exempt from APEN and reporting requirements. On July 10, 1995, the U.S. EPA issued a White Paper designed to streamline and simplify the development of Part 70, Title V permit applications. The White Paper explains that Part 70 provides permitting authorities considerable flexibility in defining certain activities or sources as “insignificant” upon proper showing of such. The White Paper itself contains substantial lists of activities or sources that are insignificant for reporting purposes.

Purpose

The addition of the following sources or activities to existing APEN exemption and reporting requirements serves a significant dual purpose and both the state and regulated community benefit from the alternate proposals. The revision of existing regulation avoids forcing an uneconomic and non-beneficial compliance requirement on the regulated community. Several of the following activities or sources are on federal lists as “insignificant,” as well as those of neighboring states. These revisions are administrative in nature, and are not intended to affect air emissions.

Non-road Internal Combustion Engines:

Machinery utilized by the construction and service industries such as various types of pumps, light plants, compressors, and generators are powered by various sizes of internal combustion engines. Most are relatively small. Some emergency equipment such as fire pumps are powered by larger engines, but are operated infrequently. The exemptions listed above identify those within this category that have insignificant emissions. This exemption is consistent with other exemptions in the regulation (see, for example, Subsections k. and l.). As a practical matter, APENS have not been required from most of these machines in the past. The sizes of most of these engines are comparable to the thousands of light and heavy trucks (gasoline and diesel powered), which travel the roads in this state without any reporting requirements.

The EPA proposal of May 17, 1990 (58 Fed. Reg. 28809) and the EPA study it references contains useful findings. It exempts all spark-ignition (gasoline, propane and natural gas powered) engines. On page 28816 of the Federal Register notice, EPA finds that it did not propose manufacturing standards for spark-ignition engines because little to no emission benefit would be achieved for testing, record keeping and reporting requirements on these engines. Cost burdens industry would have to bear would not be reasonable. It also found that test procedures have not been demonstrated to be capable of accurately predicting the levels of hydrocarbons, carbon monoxide and particulate matter emissions generated by these engines in actual use. In addition, the economics and failure problems associated with gasoline-powered engines dictate that relatively small sizes of gasoline engines are used for the light commercial equipment described above. As a result, all spark-ignition engines should be exempt from APEN reporting and classified as an insignificant activity.

The EPA study found that it could also exempt engines located on a trailer or truck bed. These engines are relatively small (dictated by trailer size and carrying capacity limitations) and power light commercial equipment, such as welders, compressors and generators, see page 28815 of the Federal Register notice.

Larger machines are typically powered by diesel engines of varying sizes. A review of emission factor data from AP-42 supports a Division of diesel-powered engines into three categories for APEN exemption purposes. Using emission factors from AP-42, expected emissions from a 175 horsepower diesel engine operating 24 hours per day, 7 days per week, 52 weeks per year at a load factor of 0.5 would present a "worst case" estimate under the 8760 hours per year "potential to emit" methodology. The following emissions are calculated:

-0.5 ton per year of carbon monoxide
-0.2 ton per year of hydrocarbons
-0.2 ton per year of particular matter
-2.5 ton per year of nitrogen oxides
-0.2 ton per year of sulfur oxides

A 300 horsepower engine could operate up to 3 hours per day, or 1095 hours per year, and have the same emissions as the 176 horsepower engines. Similarly, an engine up to 750 horsepower could operate 1 hour per day, or 365 hours per year and have the same emissions as the 175 horsepower engine class.

This approach is consistent with the approach taken by the EPA in its Guidance Document for "Calculating Potential To Emit for Emergency Generators," issued September 6, 1995. There, the EPA agreed that the use of 8,760 hours per year for calculating the potential to emit for emergency generators did not control. Instead, EPA recommended that the potential to emit be based upon an estimate of the maximum amount of hours the generators could operate based on a case-by-case basis where justified by the source owner or permitting authority. Surface water storage impoundment of non-potable water and storm water evaporation ponds: Chemical analysis and observation of these sources has consistently demonstrated that they are a negligible emission source of any regulated air pollutant.

Non-potable water pipeline vents:

Proper flow through of non-potable water maintains these sources as insignificant. Proper flow keeps the water in line from becoming septic and therefore a negligible source of any regulated air pollutant.

1. Steam vents and safety release valves:

   Safety release valve vents enable immediate reduction of pressure in steam lines. Emissions out of the safety valves consist only of pure water vapor.

2. Deaerator/vacuum pump exhausts:

These are negligible sources of emission of any regulated air pollutant.

3. Seal and lubricating oil systems for steam turbine electric generators:

Atmospheric vents exist in coal-fired utility turbine lube oil systems enable removal of water vapor from lube oil return lines from the turbine and generator bearings. This enables atmospheric pressure operation of lube oil storage tanks. These are not storage systems, but actual service operations. Calculations reveal that these activities would emit less than one ton of VOC's a year, per facility.

4. Venting of natural gas lines for safety purposes:

To enable the safe delivery of fuel gas to the utility boilers, and provide the ability to safely purge natural gas from fuel lines within a generation building, vent lines exist to allow the intermittent discharge of natural gas to safe areas away from personnel and ignition sources.

The intermittent discharge of natural gas would occur during start-up and shutdown of the natural gas supply to generating unit burners to purge air or natural gas from the piping system within the generation building. These activities are not expected to emit more than one ton of VOC's or more than 110 pounds of hexane a year.

Sulfuric acid storage tanks not to exceed 10,500 gallons capacity and sodium hydroxide tanks:

Sulfuric acid and sodium hydroxide, used to control pH, are stored in tank systems vented to the atmosphere. These vents will exhaust vapor from a tank system through vapor extraction and contraction because of changes in temperature and barometric pressure. These losses, which are referred to as breathing losses, occur without any significant change in liquid level in the tank, and are negligible.

Waste lubricating oil storage tanks not larger than 40,000 gallons and lubricating oil-conditioning systems:

Low volatility waste turbine and motor lube oil generated by utility plant machinery and mobile heavy equipment is stored in tanks. These tanks are equipped with atmospheric vents on the tops of the tanks. Emissions through these vents are expected to occur during the filling and emptying of the tanks. These emissions contain trace amounts of VOC's, with no other reportable emissions expected. Based on the low annual throughput of these tanks, emissions are insignificant, assuming that the tanks are emptied approximately five times per year or less.

Colorado Utilities Coalition for Clean Air - Part A, Section II.E.1

This Statement of Basis, Specific Statutory Authority and Purpose complies 24-4- with the requirements of the Administrative Procedure Act, C.R.S. 1973, Section 103(4) for adopted or modified regulations.

Basis

The current provisions of Regulation Number 3, Part A, Section II.E.1, were designed to postpone reporting of non-criteria reportable pollutants by sources such as utility and non-utility industrial boilers and small municipal generators pending the results of ongoing studies being conducted by EPA pursuant to Section 112(n) of the federal Clean Air Act. EPA was directed by Congress to complete those studies within three years after enactment of the federal act, i.e., by November 15, 1993; however, EPA has yet to do so.

Both the Commission and the regulated community were hopeful that EPA would be able to finish its work by the fall of 1995 so sufficient time was available for utilities to meet the original December 31, 1995 deadline. The EPA did not meet that deadline, and the Commission granted a deferral until June 30, 1996. The EPA study is now the subject of further delay due to one of the individual constituent hazardous air pollutant studies and the extensive federal government furloughs in both late 1995 and early 1996 that substantially contributed to further delay the study's progress.

Specific Authority

Section 25-7-114.1 provides authority to the Commission to identify APEN reporting requirements. There currently are no federal reporting requirements concerning emissions of non-criteria reportable pollutants (NCRPs) or hazardous air pollutants (HAPs) from boilers. The current state regulations exceed federal regulatory requirements with respect to APEN reporting of emissions.

Purpose

A short postponement of the amended deadline serves a significant dual purpose and both the state and the regulated community benefit from a deferral in this instance. The postponement avoids forcing an uneconomic and non-beneficial compliance requirement at this time on the regulated community. Since there are no compliance obligations respecting HAP emissions from boilers, either in effect or proposed, EPA and Division interpretations provide that an applicant for a Title V operating permit need only list - not estimate quantities of emissions of - HAPs reasonable believed to be contained in the boiler emissions in an application for an operating permit. This revision is administrative in nature, and is not intended to affect air emissions.

**I.W. Adopted March 21, 1996**

**Revisions to Part B, Section III.D.1.f, Section IV.C.1.e, Section IV.C.1.f, and Section IV.C.**

The changes to Regulation Number 3 were adopted in order to make it clear that the redesignation of the Denver metropolitan area as an attainment maintenance area for ozone does not change the requirement for gasoline stations in the Denver metropolitan area are to obtain a construction permit.

Section III.D.1.f appears to imply that, upon such redesignation, gasoline stations in the Denver area would not be required to obtain a permit because that area would become an attainment area. However, Section III.D.5 goes on to provide that such exemptions do not apply because gasoline stations are subject to the RACT requirements of Regulation Number 7, Section VI.B.3.b. The purpose of the revisions is simply to make it clear from the text of Regulation Number 3, Part B, Section III.D.1.f alone that gasoline stations in the Denver area are still required to obtain a construction permit. The revisions to Sections IV.C.1 and IV.C.4 were necessary to ensure that permits for de minimis exemptions from, and alternative means of compliance with, the requirements of Regulation Number7 are subject to review and comment by the public and by EPA. Such comment and review is necessary because the Sections I.A. and II.D of Regulation Number 7 provide the agency with the authority to revise the requirements that apply to a source without revising the SIP. The SIP requirements were developed and adopted following review and comment by EPA and the public. It follows that any change in those requirements with respect to any source or category of sources should also be subject to such public comment and review. The specific statutory authority to amend this regulation pertaining to exemptions from permit requirements is set out at § 25-7-114.2. Further statutory authority can be found in the Commission's authority to redesignate the area because such redesignation must include an approvable maintenance plan. The specific statutory authority to promulgate the rules necessary for redesignation is set out in § § 25-7-105(1)(a)(I) and (2); -106(1)(a); -107 (1) and (2.5); and -301.

This revision to Regulation Number 3 is not intended to reduce air pollution and will have no regulatory effect on any person, facility or activity.

For clarification, the Commission adopted these regulation revisions as follows:

| Regulation Revision | Ozone SIP and Maintenance Plan |
|---|---|
| Part B, Section III.D.1.f | Exists in Appendix C of the Ozone Maintenance Plan to be come a part of that document approved March 21, 1996 |
| Part B, Section IV.C.1.e and f; Section IV.C.4 | Adopted as subsequent regulation revisions to be submitted to the Governor and EPA Separately and concurrently as a revision to the SIP (and Maintenance Plan). |

**I.X. Adopted June 20, 1996**

**Revisions to Part A, Section V.C.1.f (Fees Correction)**

Basis

This revision corrects an erroneous regulation change requested by the Division in response to an EPA letter of September 19, 1994, which provided comments on the revisions to Regulation Number 3 for the operating permit program. The comment made by EPA was for clarification, not a requirement that the State should not charge for fugitive emissions. The change requested by the Division in 1995 included the term fugitive emissions in the paragraph of exclusions from the definition of regulated pollutant. Because of this change, the Division's authority under the statute to charge annual fees for fugitive emissions became confused which affected the Division's ability to cover its operating costs through fees. The regulation text also no longer conformed to Section 25-7-114.7, as revised in the 1996 legislative session.

Authority

Section 25-7-114.6.(3), C.R.S., requires that the revenues from fees collected by the Division approximate the annual appropriations to the Division to carry out its duties with respect to stationary sources. Section 25-7-114.7, C.R.S., requires imposition of an annual emission fee on stationary sources, and defines what is a regulated pollutant for purposes of these fees.

Purpose

These changes address an erroneous March 1995 revision made with respect to the charging of fees for fugitive emissions. The revision specifically exempted fugitive emissions and would significantly reduce the Division's ability to collect fees sufficient to cover duties with respect to stationary sources. In 1992 the General Assembly prohibited imposition of annual fees for fugitive dust or fugitive emissions as those terms were defined at the time in "Commission rule I.B.1 of regulation number 3, 5 CCR 1001-5." That rule defined only fugitive dust and the March 1995 regulatory revision inadvertently addressed fees on fugitive emissions as well. This rule conforms the regulation to statute, and eliminates any ambiguity between the two. Moreover, during the 1996 legislative session, the legislature in HB1271 amended Section 25-7-114.7(1) to clarify the authority of the Commission to assess fees for fugitive emissions. The Commission intends that all forms of "fugitive dust," regardless of whether the dust is of a size or substance to adversely affect public health or welfare, is excluded from the definition of "regulated pollutant", for purposes of annual fees.

The Commission determines that these revisions are administrative in nature and are not intended to reduce air pollution.

**I.Y. Adopted June 20, 1996**

**Revisions to Part A, Section I.B.9, 59, Section V.C.12; Part B, Section III.D.2; Part C, Section II.A.1.b, Section VI.A, E, H.3 and Section XII.A.1;Appendices B, C and D for Hydrogen Sulfide**

Background

The Division requests that the Commission adopt changes to Parts A and C and the Appendices within Regulation Number 3 to better reflect current EPA implementation of the Title V operating permit program. These changes include: (1) noting that a source major only for Total Suspended Particulate (TSP) is not required to obtain an Operating Permit in Part C; (2) deleting the Hazardous Air Pollutant reference beside the pollutant Hydrogen Sulfide (H2S) in Appendices B, C, and D of Regulation Number 3 to reflect the federal delisting of this pollutant, and; (3) expanding the definition of "applicable requirement" in Part A to clarify that EPA-issued PSD permits are applicable requirements of the Operating Permit Program. A discussion of each of these changes follows.

The current notation under Regulation Number 3, Part C Section II.A, General Considerations, lists all major sources as being required to obtain Operating Permits. The EPA has issued a written guidance document indicating that the definition of regulated air pollutant for purposes of Title V applies only to emissions of PM-10, and not TSP. The current requirements reflected in Part C, Section II.A.1.b does not reflect the federal program requirements.

Currently, H2S is reflected as a Hazardous Air Pollutant in Appendices B, C, and D. The EPA stated that the inclusion of H2S on the federal list was a typographical error and removed the pollutant from the federal list. As a result of the reference to H2S as a hazardous air pollutant in the Appendices, sources emitting H2S have been charged annual fees for HAPs and sources major for H2S emissions could be required to get an Operating Permit.

The current definition of applicable requirement in Part A, Section I.B.9.a does not provide authority for EPA-issued PSD permits to be incorporated into Operating Permits. The definition of "applicable requirement" in Part 70 of the federal program includes permits issued by EPA. The State needs this regulatory change to make the rules consistent with the federal law. Currently, regulated entities subject to these requirements can obtain a permit from EPA or can voluntarily have the requirement placed in their Title V permits, but this situation does not support the intent behind the Title V program.

Specific Authority

The specific authority for changes to this regulation is found in the Colorado Pollution Prevention and Control Act. Section 25-7-105(12) provides authority to promulgate regulations, which are necessary to implement the minimum elements of Title V. Section 25-7-103(1.5) allows the Commission to define air pollutant consistent with the federal act. Section 25-7-114.4(1)(l) and Section 25-7-114.4(3)(a) provide authority for promulgating regulations for the effective administration of construction and operating permits, and complying with all applicable requirements for operating permits. Section 25-7-114.5 provides authority for evaluating permit applications to determine whether operation and emissions comply with all applicable emission control regulations. Relevant federal law includes 42 U.S.C. Section 7661a(b)(5)(A), and 40 C.F.R. Sections 70.1(b), 70.3, and 70.6(a)(1) regarding applicable requirements. Commission action in making changes to Regulation Number 3 is taken pursuant to the above statutory provisions.

Purpose

The amendments adopted by the Commission add language in Regulation Number 3, Part C, Section II.A.1.b indicating that a source that is major only for TSP is not required to receive an Operating Permit. This amendment ensures conformity with the federal law.

The amendments delete the reference to Hazardous Air Pollutant noted next to hydrogen sulfide in Appendices B, C, and D. This ensures consistency with the Federal delisting and eliminates the potential confusion for sources that will be major only based on emissions of hydrogen sulfide as a Hazardous Air Pollutant to obtain an Operating Permit. The amendments expand the definition of applicable requirement in Part A to include those permits issued by EPA under Part C and Part D of the federal act. This ensures conformity with the federal law.

The amendments correct a few typographical errors that existed in Regulation Number 3, Parts A, B, and C.

Finally, the amendment to Part C, Section II.A.1.b, regarding TSP, is administrative in nature and is intended to reflect current EPA policy; it is not intended to reduce air pollution. The amendment to Part A, Section I.B.9.a, regarding the definition of applicable requirement, is administrative in nature and reflects the requirements of Part 70. This action regarding the definition of applicable requirement maximizes air quality benefits in the most cost effective manner by enabling sources to incorporate federally issued PSD permit into their Operating Permit. Thereby, these sources will only be reporting to one enforcement authority. These revisions applicable to Part C are not to be submitted as part of the State Implementation Plan.

**I.Z. Adopted October 24, 1996**

**Revisions to Generic Part A, Section V, (with Regulation Number 5, Emissions Trading and Banking**

This Statement of Basis, Specific Statutory Authority and Purpose complies with the requirements of the Colorado Administrative Procedures Act, Section 24-4-103, C.R.S. and the Colorado Air Pollution Prevention and Control Act, Sections 25-7-110, 25-7-110.5 and 25-7-110.8, C.R.S.

Basis

The Division has worked with the emissions trading and banking subcommittee to develop Regulation Number 5 and revisions to Regulation Number 3 for the purpose of implementing an EPA-approvable emissions trading program.

The subcommittee has developed a trading rule combining elements from the existing EPA guidance and the prior Commission rule. The subcommittee spent a great deal of time discussing the issues around the possible uses for credits, how credits could be certified, and how they should be traded and tracked.

Emission reduction credits are intended to be granted only for reductions beyond compliance levels that are actual, quantifiable, surplus and enforceable. This rule is not intended to impose additional control limitations on sources. The rule does impose requirements to ensure that these basic criteria are met in order to guarantee that the source flexibility afforded by this program does not occur at the expense of air quality.

This rule is a revision to the SIP done only under the Commission's general authority. Thus, the trading and banking rule will not be state enforceable until after legislative review. Section 25-7-133(2), C.R.S. Additionally, because EPA must approve this change into the SIP, the Commission finds it appropriate to delay the effective date of these revisions until EPA approval as a SIP revision. This will provide the sources that might wish to participate the assurance that the rule is approved and that the credits are useable prior to the implementation of the program. The existing trading provisions in Regulation Number 3 will remain in effect until the new trading rules are approved by EPA. These constraints on the effective date of these revisions are reflected in the rule text approved by the Commission. In addition, in order to avoid confusion about what portions of the regulations are effective until EPA approval of the SIP change, the parts of Regulation Number 3 that will be repealed are printed in italics.

State implementation plans are to include, among other things, enforceable emissions limitations and other control measures, means or techniques to meet the requirements of the Clean Air Act. These are to include economic incentives such as fees, marketable permits, and auctions of emissions rights. 42 U.S.C. 7410(a)(2)(A). These regulation revisions are being submitted as a SIP revision pursuant to the foregoing Clean Air Act requirements.

The following issues were identified by the subcommittee and noticed by the Commission for further consideration. The Commission discussed and resolved these issues in the course of this rulemaking proceeding and makes the following findings regarding these issues.

Issue: Once used, does a permanent emission reduction credit (ERC) ever expire? Some believe that an ERC once used, even if from a permanent reduction, should expire after some period (e.g., 20 years).

Conclusion: The Commission, based on the experience in the previous trading rules, decided that the permanent credits should not expire after they are put into use.

5. Issue: Should a decrease in electrical demand be usable to generate emission reduction credits?

Conclusion: Because of the existence and operation of the national electrical grid system, the Commission believes that it would be far too difficult to verify that there had been a decrease in demand (a decrease in actual emissions) and not a variation in the grid structure, and therefore at this time finds it is inappropriate to allow a decrease in demand to generate ERCs.

6. Issue: As the proposed rule is written, inter-pollutant trading is allowed on a case-by-case basis subject to Division approval. The subcommittee and the Division recognized that a universal or standard protocol for approving such trades would be desirable, but that no officially approved protocols for any inter-pollutant trades exist.

Conclusion: The Commission agrees that there is currently insufficient scientific information available to support inter-pollutant trades in most cases. In order to ensure that the Division staff is not placed in the position of having to develop information and protocol to support an inter-pollutant trade proposal, the Commission finds that the burden of proving the acceptability of an inter-pollutant trade shall be placed on the source.

Because of concerns expressed by the EPA that the protocol for inter-pollutant trades has not yet been developed, the language of VI.B. was amended to allow proponents of such trades the opportunity to

make their case to the Division and EPA for approval. This amendment attempts to address the EPA concern.

7. Issue: The proposed rule states that temporary credits must be credited and traded within the same "season" for seasonal pollutants. Should temporary credits be allowed to be traded from a season of lower concern to a season of higher concern?

Conclusion: The Commission finds that the use of temporary credits should be restricted to the same season in which they were generated, or a season of lower concern. This will help mitigate any significant increases in seasons that may cause a violation of the NAAQS.

Issue: At this time no internal provisions exist for program development and implementation. How should the cost of the program implementation and development be addressed?

Conclusion: The Commission acknowledges that the Division will monitor the activity in the trading program and, if needed, legislative fee authority will be sought. Fees for permit changes required by this rule will be charged pursuant to Regulation Number 3. Nevertheless, the Commission acknowledges that resources are not currently available and funding may be needed for this program.

8. Issue: Should the rule contain procedures or criteria specific to trading Hazardous Air Pollutants (HAPs)? The subcommittee and the Division agreed not to address this issue of HAPs in the proposed rule.

Conclusion: The Commission is concerned that use of ERCs for criteria pollutants that contain or consist of HAPs could unduly increase the risks to communities and the environment in the vicinity of the credit-using source. Assessing relative risk is difficult, time-consuming and highly fact-specific to a particular source and trade. In order to address this concern, the Commission adopted Section VI.G.8 that requires that the HAPs reduced to generate the ERC must be of equal or greater toxicity than the HAPs contained in the emissions for which the ERC will be used in lieu of satisfying an applicable requirement. Section VI.G.8 does not operate as an emissions control regulation on any HAPs, but is simply a limitation on participation in the trading program.

9. Issue: How is the base emission rate set? In order to show the level of actual emissions at a source before reductions for which credits are claimed, a period representative of normal operating conditions must be used.

Conclusion: The Commission adopts provisions that require using the last twelve months' actual emission rate unless the last twelve months are not representative. The source may propose to the Division to use any consecutive twelve months in the last ten years as more representative of normal unit operations. This allows most sources to use a period, which the Commission believes is likely to be representative of normal operating conditions. Where the source can show that the period is not representative, the rule allows source flexibility in determining their pre-reduction actual emissions.

10. Issue: Should the Commission give authority to the Division to allow discounts from the ten percent contribution of emission reductions for air quality benefits for generators that participate in a voluntary pollution prevention program or other voluntary "beyond-compliance" programs? Should a generator be allowed to contribute only five percent of its their emissions reductions for air quality benefits as an incentive for participation in pollution prevention programs?

Conclusion: The Commission agreed to provide such flexibility to the Division for generators that have voluntarily adopted comprehensive and facility-wide environmental programs such as a Pollution Prevention Program or other similar voluntary "beyond-compliance" programs.

11. Issue: Should ERCs be used to satisfy Best Available Control Technology (BACT) or Lowest Achievable Emission Rate (LAER) requirements where a source triggers PSD or nonattainment New Source Review and must install BACT or LAER control technologies? Recent reports in the national press have indicated that EPA is giving serious consideration to allowing ERC use for BACT as it attempts to move away from command-and-control approaches to more contemporary market approaches.

Conclusion: The Commission believes that ERCs may appropriately be used in lieu of the emissions reductions which would otherwise be achieved by application of the BACT technology requirements in situations where such technology requirements are not cost-effective or exacerbate other pollutant emissions, and the use of an ERC would achieve the same purposes more efficiently. In such instances, it will be incumbent on the source to demonstrate that such a situation exists. In any case, however, the other PSD provisions and required analyses would apply to the source. PSD requirements are performed on future allowable emission rates. Because of concerns about the use of ERCs for BACT requirements, although the Commission has allowed ERCs to be used to meet BACT requirements in limited instances, it believes that this provision should only be applied prospectively for new BACT requirements and not to allow a source to remove BACT where it has already been installed. The Commission concludes that use of ERCs in lieu of emissions reductions from LAER is not appropriate because of the potential impacts on nonattainment areas.

12. Issue: How will the local effect of “hot spot” pollutant trades be analyzed to prevent a local criteria pollutant exceedance due to emission credit transactions? Should the rule require modeling of criteria, pollutants to assure there are no exceedances of the National Ambient Air Quality Standards? Conclusion: The Commission adopts the language in Section VI.G.7 of Regulation Number 5 requiring modeling for all trades in order to ensure that trades do not cause or contribute to a NAAQS exceedance, an increment exceedance, or any violation of a required SIP provision. As that Section reflects, the source may request that the Division waive the modeling requirement if the source can document to the Division's satisfaction that the trade has a negligible impact.

13. Issue: How and who modifies the conformity budget for intersector trading? With mobile to stationary source trades, does the emission budget increase after the life of the credit has expired, and how is this accomplished?

Conclusion: The Commission has provided for ERCs to be available to satisfy conformity requirements in accordance with the federal rules. The Transportation Conformity requirements (40 CFR Parts 51 and 93) presently allow for trades among emissions budgets where either a SIP revision or a SIP establishes mechanisms for such trades. 40 CFR §93.124(c). The Colorado emissions trading rule is intended to be a SIP revision establishing such a “mechanism” to allow for such trades.

The Commission recognizes that, if mobile source emissions rise above the mobile source emissions budget in the state implementation plan, a plan revision may be necessary as otherwise required by state and federal law.

14. Issue: What becomes of the “buffer” between a credit-generating source's potential to emit and its actual emissions before the reduction for which the credit is claimed? Does the generator get to keep a portion, all, or none of it?

Conclusion: The Commission finds that methods exist to allow a source to retain the operating flexibility from a pre-reduction “buffer.” When a source wants such flexibility, it may claim credits for less than the entire reduction in emissions accomplished; the difference constitutes a new “buffer.” A source may use temporary credits to meet short-term operating needs.

These methods retain flexibility for the source without relying on "paper reductions." The Commission concludes that it is imperative that reductions for which credits are granted must be actual reductions. Allowing a source to retain a buffer from within the credits granted, as proposed by the Colorado Association of Commerce and Industry, would result in credits for "reductions" which did not actually occur. This result is unacceptable, particularly because sources determine their own permitted emissions levels when they file their Air Pollution Emission Notices.

For example, a source with a ninety-five ton per year permitted level that actually emits fifty tons reduces its emissions to forty tons. The source should take a new permit with a level between forty and fifty tons (e.g., forty-five tons) so that the source has a five-ton buffer. The source may then fluctuate its emissions between forty and forty-five tons without violating the permit, and generate temporary credits for any emissions reductions below forty-five tons.

In order to ensure that reductions are actual, an ERC-generating source will not be able to increase its permitted emissions in the absence of a process or control modification. The source cannot, for example, simply file an APEN with higher emissions estimates and thereby increase its permitted emissions. The effect would be to allow emissions for which credits were already granted, resulting in "paper reductions." This consequence is unacceptable.

15. Issue: Should a closer relationship be established between emission trades and the various pollutant-specific SIP elements? With regard to the spatial distribution of emissions, the rule as proposed did not acknowledge any sub-regional emission budgets, dispersion modeling requirements, or other spatial considerations contained in attainment and maintenance demonstrations for specific SIP elements.

Conclusion: The original proposed regulation did not have a modeling requirement for ERC use. The Division subsequently proposed that modeling be required prior to an ERC use unless the source requests that such modeling be waived and the source can show that the ERC use would have a "negligible" impact. The Colorado Association of Commerce and Industry expressed a concern that the Division would require costly or unnecessary modeling in most cases. This concern stems from the lack of definition of what is "negligible" in the judgment of the Division. The Commission believes that modeling should only be required where the location or circumstances of the ERC use would reasonably be expected to cause or contribute to a NAAQS violation, an increment exceedance, or violation of a SIP provision such as near a "hot spot" in a nonattainment area or where ambient conditions are within 5% of any applicable standard. The Commission, based on the explanation offered by the Division, believes that the modeling required by the rule as adopted will adequately address this issue.

16. Issue: Should the emission trading rule clarify whether trades can take place among different air sheds/Air Quality Control Regions.

Conclusion: The Commission adopts two levels of limitations on the geographic scope of trading. First, trades are limited to sources within the same nonattainment area or from a source in a nonattainment area to one in an attainment area. Second, all trades must be between sources within the same PM-10 PSD areas. These limitations are intended to avoid excessive impacts on local communities and Class I areas from long-distance trades.

In addition to the issues discussed above, the Commission also considered concerns about granting ERCs for emission reductions that occurred in the past. This rule allows a source to use credits generated under the old rule and to seek credit certification for reductions, which occurred prior to adoption of this rule. However, the Commission wants to emphasize that past emission reductions, which have been used to demonstrate attainment or reasonable further progress for SIP purposes are not eligible to qualify as ERCs.

The Commission recognizes that use of ERCs in lieu of compliance with an emission limitation may raise public concerns in the vicinity of the credit-using source. For this reason, the rule anticipates that notice to the Division will be required prior to use of ERCs. Permanent ERC use must be accomplished through a permit change. Temporary ERC use may occur only after an APEN is filed with the Division. Each of these documents is available to the public. Notices of ERC use will be published on the ERC Trading Network by the Division. The provisions of Regulation Number 3 requiring and allowing public notice and comment of proposed permits and modifications will also apply to permit actions to approve use of ERCs. The Commission believes that use of the Division's discretion to seek public comment needs to be supplemented in order to provide sufficient information to the public regarding proposed uses of ERCs. Accordingly, the Commission has included a requirement that the Division notify local governments in the affected area when the trade will result in the use of ERCs, which would exceed the threshold for, or otherwise trigger, public notice and comment pursuant to Section IV.C.1 of Part B, Regulation Number 3. The Commission anticipates that local governments will be able to use this notice to schedule informational meetings for citizens, which Commission members and appropriate Division staff will be able to attend. The Commission also emphasizes that the Division should exercise appropriate discretion to provide public notice and comment for trades that involve HAPs, which would be implemented by notifying the local government pursuant to the process described above.

The Commission elected to preclude trading of elemental lead because of that pollutant's particular characteristics and modified the definition of criteria pollutant for the purposes of this regulation.

The Commission included Section IV.A.1.d. in this regulation to ensure that ERCs are granted only for real overall reductions in emissions. This provision ensures that reductions will be creditable only if the emissions are not replaced in the airshed by another generator in a business of like kind. In order to assure that this program does not grant credit for “paper” reductions, the rule prohibits generating ERCs where this business shift will replace emissions within the same airshed. This determination will be made on a case-by-case, fact-specific basis.

Specific Statutory Authority

These regulation revisions are adopted under the general authority of the Commission found in Section 25-7-105(1), C.R.S. and are consistent with 42 U.S.C. 7410(a)(2)(A).

Purpose

This rule was proposed in order to provide the maximum flexibility for sources in meeting the state and federal requirements outlined under the possible uses for credits. The Commission makes the following findings in regards to the adoption of this regulation:

1. The Commission has considered, and has based its decision, on the reasonably available, validated, reviewed and sound scientific methodologies and information made available by interested parties.

2. Where these revisions are not administrative in nature, the record supports the conclusion that the provisions adopted will result in a demonstrable reduction in air pollution. This reduction is accomplished through the retirement of 10% of the achieved reduction in emissions.

3. The revisions selected maximize the air quality benefits of the emissions standards that apply. The revisions selected are the most cost-effective based on the documents submitted by the parties under Section 25-7-110.5, and provide the regulated community with flexibility in meeting emissions limitations. Although the requirement for increased emissions modeling may impose additional costs, the Commission believes this requirement is necessary to ensure that no violations of air standards will occur as a result of using ERCs.

**I.AA. Adopted November 21, 1996**

**Revisions to Appendices B, C**

This Statement of Basis, Specific Statutory Authority and Purpose complies with the requirements of the Colorado Administrative Procedures Act, Section 24-4-103, C.R.S. and the Colorado Air Pollution Prevention and Control Act, Section 25-7-110.5, C.R.S.

Basis

Regulations 3, 7 and the Common Provisions establish lists of Negligibly Reactive Volatile Organic Compounds (NRVOCs). The revisions adopted update the list of NRVOCs so that the state list remains consistent with the federal list. Additionally because perchloroethylene will no longer be listed as a VOC in Regulation Number 7, Section XII, Control of VOC Emissions from Dry Cleaning Facilities using Perchloroethylene as a Solvent, is being deleted.

Regulation Number 8 and 3 list the federal Hazardous Air Pollutants (HAPs). In the June 8, 1996 Federal Register the EPA removed Caprolactam (CAS 105-60-2) from the federal list of Hazardous Air Pollutants. The conforming changes in Regulation Number 3 Appendices B, C and D have been made to keep the list of federal HAPs in Regulation Number 3 consistent with the federal list. The list of HAPs in Regulation Number 8 has been removed and a reference to the list in Regulation Number 3 has been added.

Specific Statutory Authority

The Colorado Air Pollution Prevention and Control Act provides the authority for the Colorado Air Quality Control Commission to adopt and modify Regulations pertaining to organic solvents and photochemical substances. Section 25-7-109(2)(f) and 25-7-109(2)(g), C.R.S., grant the Commission the authority to promulgate regulations pertaining to organic solvents and photochemical substances. Sections 25-7-105(1)(l)(b) and 25-7-109(2)(h) provide authority to adopt emission control regulations and emission control regulations relating to HAPs respectively. The Commission's action is taken pursuant to authority granted and procedures set forth in Sections 25-7-105, 25-7-109, and 25-7-110, C.R.S.

Purpose

These revisions to Regulations Number 3, 7, 8 and the Common Provisions are intended to update the state lists of NRVOCs, the Ozone SIP, and HAPs for consistency with the federal lists.

**I.BB. Adopted November 18, 1999**

**Revisions to Part C Incorporation by Reference of New and Revised Federal Regulations Concerning Compliance Assurance Monitoring (40 C.F.R. Parts 64, 70, and 71) into Colorado Air Quality Control Commission Regulation Number 3, Part C, Addition of Section XIV.**

Background

This Statement of Basis, Specific Statutory Authority and Purpose complies with the requirements of the Administrative Procedures Act, C.R.S. (1988), Sections 24-4-103(4) and (12.5) for adopted or modified regulations.

Pursuant to Section 114 of the 1990 Clean Air Act Amendments ("CAAA"), the U.S. Environmental Protection Agency ("EPA") promulgated new regulations in 40 C.F.R. Part 64 and revised regulations to 40 C.F.R. Parts 70 and 71 to implement compliance assurance monitoring ("CAM") for pollutant specific emission units at major stationary sources of air pollution that are required to obtain Title V operating permits. The requirements imposed by the CAM rule are separate from the requirements of EPA's "periodic monitoring" rule found at 40 C.F.R. Section 70.6(a)(3)(i). The periodic monitoring rule requires that each operating permit contain any emissions monitoring or test methods already required by an applicable requirement including any "periodic monitoring sufficient to yield reliable data from the relevant time period that are representative of the source's compliance with the permit . . . such monitoring shall assure use of terms, test methods, units, averaging periods, and other statistical conventions consistent with the applicable requirement." See 40 C.F.R. Section 70.6(a)(3)(i)(B) (emphasis added).

Subject to certain exemptions, the new CAM regulations require owners or operators of such sources to conduct monitoring that satisfies particular criteria established in the rule to provide a reasonable assurance of compliance with applicable requirements of the Act. Monitoring requirements contained in the rules focus on emissions units that rely on pollution control equipment to achieve compliance with applicable standards. The CAM regulations also provide procedures for coordinating these new requirements with the Operating Permits Program regulations.

The CAM regulation generally will not require implementation of its requirements for most units subject to CAM until the first round of Title V permit renewals, which will generally be five years after initial Title V permit issuance.

The following table reflects the schedule by which CAM plans must be submitted by owners and operators of affected emissions units:

| Pollutant Specific Emission Unit (PSEU) Size | CAM Plan Due as part of the Operating Permit INITIAL Application | CAM Plan Due as part of the Operating Permit REVISION Application | CAM Plan Due as part of the Operating Permit RENEWAL Application |
|---|---|---|---|
| "Large" PSEU (see 40 C.F.R. Section 64.5(a)) | If Title V permit application is not complete by 4/20/98 OR if PSEU part of a greenfield permit application after 4/20/98 | If a significant permit revision[1] at an existing Title V source | If Title V permit application was complete before 4/20/98 |
| "Other" PSEU (see 40 C.F.R. Section 64.5(b)) | Never | Never | Always |

1. "significant permit revision" is defined as "significant permit modification" in Colorado Air Quality Control Commission Regulation Number 3, Part A, Section I.B.36.h. This definition is subject to change when the federal Part 70 revisions are promulgated and adopted by the Colorado Air Quality Control Commission.

In the event of a significant proposed operating permit modification that may trigger the earlier application of the CAM rule, the rule's provisions only become applicable with respect to those pollutant specific emission units for which the proposed operating permit revision is applicable. See 40 C.F.R. Section 64.5(a)(2).

Basis

Regulations to implement these CAAA mandates were originally proposed in 1993 as the "enhanced monitoring" program. The enhanced monitoring proposal focused on monitoring air emissions as a means of ensuring source compliance with CAAA emission limitations and operating permit conditions. The EPA received approximately 2,000 comment letters to the enhanced monitoring proposal. In response to these comments and through a series of stakeholder meetings, the agency decided to redesign the Part 64 program. In 1995, the EPA promulgated a revised draft Part 64 rule, which is now known as the CAM rule. The final CAM rule was promulgated on October 22, 1997.

The Commission heard testimony from members of the public who were concerned that the implementation of the rule would have the effect of making existing applicable requirements more stringent. It is the Commission's understanding however that this is not the purpose nor should be the result of implementation of the CAM rule. In adopting the CAM rule by reference, the Commission does not intend that existing applicable requirements become more stringent.

Authority

Section 25-7-105(12), C.R.S. (1997) provides authority to promulgate regulations that are necessary to implement the minimum elements of Title V of the Clean Air Act. Section 25-7-106(6), C.R.S. (1997) provides the Commission with the authority to require testing, monitoring and record keeping. Commission action in promulgating these regulations is taken pursuant to the above statutory provisions. The Commission is not adopting the CAM rule in this incorporation by reference as part of the Colorado State Implementation Plan. For that reason, the provisions of Section 25-7-105.1 C.R.S. (1999) regarding federal enforceability do not apply.

Purpose

Adoption by reference of the Federal CAM regulations contained in 40 C.F.R. Part 64, and the revisions to 40 C.F.R. Parts 70 and 71 make the regulations enforceable under Colorado law. Adoption of the regulations will not impose upon sources additional requirements beyond the minimum required by Federal law, and may benefit the regulated community by providing sources with up-to-date information.

**I.CC. Adopted November 15, 2001**

**Revisions to Regulation Number 3, Part B: Concerning Construction Permits, Including Regulations for the Prevention of Significant Deterioration**

This Statement of Basis, Specific Statutory Authority and Purpose complies with the requirements of the Colorado Administrative Procedures Act, Section 24-4-103, C.R.S., and the Colorado Air Pollution Prevention and Control Act, Sections 25-7-110 and 25-7-110.5, C.R.S., and implements Sections 25-7-105(17) and 25-7-212, C.R.S.

Basis

The rule revisions adopted implement the provisions of House Bill 99-1351. Regulation Number 3 contains permitting, monitoring, reporting, visibility protection, and fee requirements.

Specific Statutory Authority

The Colorado Air Pollution Prevention and Control Act, Section 25-7-105(17), C.R.S., provides the authority for the Commission to hold hearings to approve emission inventories related to state and federal lands. That subsection also directs the Air Pollution Control Division to prepare inventories for all state land management agencies with jurisdiction over state lands. Section 25-7-212, C.R.S., requires federal land managers to develop a plan for evaluating visibility in mandatory class I federal areas and to provide to the state an emission inventory for pollutants that affect any mandatory federal class I area within Colorado. This Section also directs the Commission to use the inventories to develop control strategies for reducing emissions within the state of Colorado as a primary component of the visibility long-term strategies.

The Commission's action is taken pursuant to procedures set forth in Sections 25-7-105, 25-7-110 and 25-7-110.5, C.R.S.

Purpose

In general, HB 99-1351 was intended to provide mechanisms for the state to develop information important to its efforts to protect and enhance visibility, particularly in mandatory federal class I areas. This bill specifies the types of information that must be reported, collected and approved for use in the state implementation plan.

Federal agencies own and administer approximately 36 % of the land in Colorado. Accordingly, the federal government has jurisdiction over many sources of emissions within the state. The inventory information developed under this regulation will provide additional information needed regarding these emissions, as well as those from similar state lands.

The rule requires that all federal and state lands have emission inventories approved by the Commission by December 31, 2002 and at least every five years thereafter. The emission inventories must include emissions in both Colorado and other states that may affect visibility in mandatory federal Class I areas in Colorado.

House Bill 99-1351 requires the first submittal of inventory information by the federal land management agencies by December 31, 2001. The Commission anticipates that the affected federal land managers may rely upon regional inventory information to satisfy in part the requirements of this rule. The regional inventory development process is in its early stages. In addition, this hearing has been continued once and accordingly this rule may not become effective before the statutory deadline for the initial federal public lands emission inventory submittal. The Commission recognizes that this created uncertainty for the federal land managers. Nevertheless, the General Assembly established the deadline for submittal of the federal public lands inventory in 1999 and the federal agencies have known about this requirement for more than two years.

The Commission anticipates that submittal of the regional emission inventory will provide enough information to reasonably meet the December 31, 2001 deadline. In order to ensure that inventories reflect the best information available, however, the Commission allowed the federal agencies an additional six months to provide supplemental information to fully meet the requirements of this rule. Any such additional information must be submitted to the Commission by July 1, 2002. The Commission is to hold a public hearing on the inventories and approve them by December 31, 2002. This schedule will still allow sufficient time for the Commission to consider and approve, if appropriate, the inventory information submitted.

The Commission believes that the emissions subject to the reporting requirements of this rule are in the order of hundreds of tons per day of criteria pollutants and that this level of emissions justifies application to federal and state land managers of reporting requirements similar to those that apply to owners and operators of other large emissions sources.

The Commission has the authority to exempt from the inventory requirements any sources or categories of sources that it determines to be of minor significance. This rule does not contain such an exemption because little is known about several of the source categories (e.g., biogenic sources). The Commission may consider at a later time whether such an exemption is appropriate based on additional information that may be gathered.

The Commission elected for the purposes of this regulation to define federal land management agencies as those agencies that own and manage at least 50,000 acres of land in Colorado. The Commission intended to exempt agencies with relatively small amounts of land (e.g., Department of Commerce, Bureau of Reclamation) from having to prepare inventories. In the Commission's view, the benefit of developing information relative to emissions from lands managed by smaller agencies did not justify the administrative burden and costs of preparing such emission inventories.

The Division is required by the bill's provisions to provide an inventory of emissions from activities of all state of Colorado land management agencies on state of Colorado lands that may affect visibility in Colorado's Class I areas. The inventory is to be delivered to the Commission by July 31, 2002 and at least every five years thereafter.

There are several requirements in the statute that have not been included in the regulation as they are largely policy directives to the Commission and Division from the General Assembly

The rule revisions adopted address the procedural mechanisms for accomplishing the mandatory requirements of House Bill 99-1351. The Commission concludes that these rule revisions are adopted to implement prescriptive state statutory requirements, where the Commission is allowed no significant policy-making options, for the purposes of § 25-7-110.5, C.R.S. The Commission also concludes that it has no discretion under state law to adopt alternative rules that differ significantly from these revisions, for the purposes of § 25-7-110.8(1), C.R.S. Accordingly, the Commission did not include in the record some of the portions of the rulemaking prerequisites addressed in § 25-7-110.5, C.R.S. and did not make specific determinations regarding the factors listed in § 25-7-110.8(1), C.R.S.

The Commission took into consideration the appropriate items enumerated in Section 25-7-109(1)(b), C.R.S.

**I.DD. Adopted July 18, 2002**

**Revisions to Regulation Number 3**

This Statement of Basis, Specific Statutory Authority and Purpose comply with the requirements of the Colorado Administrative Procedure Act Sections 24-4-103(4) and (12.5), C.R.S. for new and revised regulations.

Basis

Regulation Number 3 sets forth the Air Quality Control Commission's permitting and air pollutant emission notice programs for stationary sources. The regulation is organized into four parts: Part A contains general provisions and the Air Pollution Emission Notice (APEN) program; Part B deals with major and minor source Construction Permits; Part C sets forth the Operating Permit program; and, Part D provides the statements of basis, specific statutory authority and purpose for revisions to the regulation. Changes have been made to each of these parts to clarify ambiguous language, eliminate duplicative or unnecessary provisions and to make the requirements more understandable and easier to read. Additionally, some substantive changes have been made to address inconsistencies between the regulation and state and federal law, to improve the permit program from an air quality protection perspective and to eliminate unnecessary burdens on the regulated community. Appendices B and C to the regulation were deleted because they were duplicative of Appendix D. The majority of the revisions were proposed by the Air Pollution Control Division based on internal review and extensive discussions with interested parties. The Division's initial proposals were addressed at length during a subcommittee process involving the Commission, the Division, stakeholders and other interested parties. During this process, participants commented on the initial proposal and offered additional suggestions. The proposal presented to the Commission is a collaborative effort of the Division and interested stakeholders.

Specific Statutory Authority

The specific statutory authority for these revisions is set forth in various Sections of the Colorado Air Pollution Prevention and Control Act ("Act"). Section, 25-7-105(1), C.R.S., gives the Air Quality Control Commission authority to promulgate rules and regulations necessary for the proper implementation of the Act, including regulations to assure attainment and maintenance of national ambient air quality standards, emission control regulations and a prevention of significant deterioration program. Section, 25-7-105(12), C.R.S., provides specific authority to establish, emission notice, construction permit and operating permit programs. Some of the statutory parameters for these programs are set forth in Sections 25-7-114, through 25-7-114.7 of the Act, and these Sections in turn, provide statutory authority for the current revisions. Additional authority for these revisions is set forth in Section 25-7-106, C.R.S., in Section 25-7-119, C.R.S., and in Section 25-7-132, C.R.S.

Purpose

A review of the previous Regulation Number 3 revealed numerous stylistic, grammatical and formatting problems, language ambiguities and obsolete or duplicative provisions. These revisions are intended to update, clarify and streamline this regulation. Additionally, changes have been made to address developments in state and federal law, to eliminate inconsistencies between the regulation and state and federal law, and to improve the programs set forth in the regulation from an air quality perspective while eliminating or minimizing undue and unnecessary burdens on the regulated community.

I. Part A Revisions

Part A of Regulation Number 3 contains a definitional Section and provisions that set forth the Air Pollution Emission Notice program and other general provisions relevant to the notice and permit programs.

A. Definition Changes

Numerous changes to the definition Section were made. Primarily, these changes were designed to fix ambiguous language, to make the definitions more readable or to delete obsolete or duplicative definitions. For example, the definition of applicable requirement was modified to clarify that it included construction permit requirements that may have been modified during the operating permit process. This definition was always intended to include such modifications, but the old language failed to clearly explain that intent. Similarly, a change to the definition of major modification was necessary to clarify that the term included both physical changes and changes in the method of operation. The prior version omitted language resulting in an ambiguity regarding this intended meaning. Changes were made to the definition of net emissions increase to clarify that in calculating an increase or decrease of emissions, sources are not committed to use the emission numbers contained in an APEN. For example, when credible demonstrable evidence indicates a different amount of actual emissions exists, this information can be used to demonstrate a net emissions decrease. The definition of significant was also changed to clarify that the Prevention of Significant Deterioration (PSD) and New Source Review (NSR)-nonattainment area (NAA) programs do not apply to certain hazardous air pollutants. Specifically, the state PSD and NSR/NAA programs exempt those hazardous air pollutants that are exempt from the federal PSD and NSR/NAA programs pursuant to Section 112(b)(6) of the Federal Act.

In addition to the clarifications, formatting and readability changes made to the definition Section, a number of definitions were added or modified to reflect developments in federal law. For example, the Commission revised the definitions of actual emissions and major modification to include special provisions governing physical or operational changes at electric utility steam generating units. These changes were necessitated by changes in the federal regulations arising out of the decision in the Wisconsin Electric Power Company ("WEPCO") case. The changes are applicable only to coal-fired electric utility steam generating units. Colorado law has required that NSR provisions be interpreted consistent with federal requirements since 1994 when the Colorado General Assembly enacted HB94-1264, Section 25-7-109, C.R.S. The WEPCO definitions have been added, consistent with EPA's regulations, in order to clarify the meaning and scope of the changes to the definitions of actual emissions and major modification. Units need not have obtained a formal applicability determination from the Division before proceeding with the physical or operational change, although doing so is at the risk of the source. Actual emissions levels may be determined from the information found in periodic APENs which sources file pursuant to Regulation Number 3, Part A., or from other credible information, such as data from continuous monitoring systems. The filings by sources in the past, such as APENs, have enabled the Division to track sources' emission increases and decreases in a manner consistent with the provisions in the WEPCO rule, therefore, the Commission believes this formal adoption should not impose a greater burden on sources in Colorado than they have historically experienced. The Commission notes that, consistent with the legislature's intent, the WEPCO provisions have been implemented by the Division in recent years. One example is the flexibility provided a change qualifying as a pollution control project.

The definition of major modification was further changed to restrict what constituted a temporary activity. Under both the old and new regulations, temporary activities are not considered to be part of a major stationary source. The old definition could be read, however, to exclude activities that constituted temporary sources under the PSD program. Such sources are subject to certain limited PSD requirements, and could be classified as an exempt temporary activity resulting in an exemption from those limited requirements. The new version clarifies that only temporary construction or exploration activities are exempt, thus preserving the applicability of the PSD temporary source requirements.

Under the definitions for major modification and major source, while emissions from temporary construction are not included in determining whether there is a major modification or source, emissions from ongoing construction are included. Several parties requested clarification as to what constitutes ongoing construction. Such a determination must be made on a case-by-case basis, but generally, construction lasting more than two years will be considered ongoing.

At the suggestion of the regulated community, the definition of commenced construction was supplemented to identify the entire range of pre-construction activities that may be undertaken without obtaining a construction permit.

Provisions governing regulation of non-road engines have undergone a complete overhaul. In addition, the definition of non-road engines was moved from the APEN exemption provisions in Part A, Section II.D.1.sss., to the definition Section of Part A. The prior regulation (Section II.D.1.sss.) exempted certain non-road engines from APEN and permitting requirements, provided these exemptions did not apply where the engines would otherwise trigger PSD, NSR-NAA review or other applicable requirements. Since the promulgation of that regulation, Congress amended the federal Clean Air Act. These amendments, as interpreted by the D.C. Circuit Court of Appeals, precluded the states from enacting emission control regulations for non-road engines except under very restricted circumstances. The Court of Appeals held, however, that states could enact use restrictions such as restrictions on the hours of operation or amount of fuel usage. To address this situation, the regulated community requested that non-road engines be specifically identified as non-stationary sources, thus exempting them from most, if not all, of the requirements of Regulation Number 3. While agreeing that non-road engines should not be treated as stationary sources, the Division expressed a concern that a large aggregation of these engines might result in a violation of ambient air quality standards. To reconcile these conflicting concerns the regulatory revisions create a new state-only non-road engine program for certain non-road engines.

The Commission's authority to establish a non-road engine program and to regulate the operation of non-road engines is set forth in 27-7-106(1) C.R.S., and through the legislative declaration in 25-7-102 C.R.S. Non-road engines subject to the program must submit an APEN and pay appropriate APEN fees. If specified emission levels are tripped in the APEN, the program further requires that the source obtain a temporary permit and pay applicable permit fees. The permit will include such use restrictions as are necessary to prevent an exceedance of ambient air quality standards. Non-road engines that are mobile or self-propelled equipment such as bulldozers, haul trucks, water trucks, loaders, shovels, backhoes, road graders, cranes or similar mobile equipment are not subject to the state-only permit program and are not required to obtain an APEN.

Whether an engine qualifies as a non-road engine as opposed to a stationary source will depend on the facts of a particular case. To qualify as a non-road engine under Regulation Number 3, Part A, Section I.B.40.a.iii., the engine must be portable. What constitutes portable will be determined on a case-by-case basis. Additionally, such portable engines lose their status as non-road engines if they remain at a location for more than twelve consecutive months. The regulation narrowly defines location such that use of a portable engine at multiple sites at a given source does not constitute use at a single location. This provision, however, is not intended to allow a source to circumvent the regulation by moving a given engine for the purpose of avoiding expiration of the twelve-month period.

For sources that have voluntarily obtained permits for a non-road engine(s) as defined in Regulation Number 3, Part A, Section I.B.40., prior to the effective date of this rule revision, a source may continue to operate under the existing permit. A modification or re-opening of the existing permit will effectively subject a source to the requirements set forth in the non-road engine state-only permit program (Part A, Sections I.B.40.c. and I.B.40.d.)

During the public hearing on this rulemaking, the Commission raised concerns regarding the flexibility and responsiveness of the new state-only non-road engine permit program in emergency or other unforeseen situations. In these situations, it is an operator's obligation to file an APEN and obtain a state-only non-road engine permit under Sections I.B.40.c., and I.B.40.d., prior to the exceedance of any trigger level (i.e., hours of operation and/or emission limitation). This clarification is intended to increase program flexibility by ensuring that operators, including local and state government, will not be penalized when responding to emergencies and business planning conditions when such conditions subsequently trigger APEN and permit application requirements under the program.

To enhance and foster program responsiveness, the Commission expects that the Division shall act to complete state-only non-road engine permit applications as expeditiously as possible. In addition, under the authority set forth in Section 25-7-114.5(5), C.R.S., the Commission has determined that state-only non-road engine permit applications shall not be designated as permit actions subject to public notice requirements.

B. Changes to APEN Program

The Division proposed to add record keeping requirements to a number of APEN exemptions. The Commission did not adopt the specific record keeping language in Part A of the regulation. The intent of the Commission, however, is that sources should have records or other information sufficient to verify that an exemption from APEN requirements can be taken in accordance with the regulatory requirements.

The Commission revised Section II.D.4.a.(vi), deleting the solvent return opening size requirement for small remote reservoir cold solvent degreasers contained in Section II.D.4.a.(vi)(A). The Commission also revised the emissions limit in Section II.D.4.a.(vi)(C) from 350 pounds of volatile organic compounds per year to one ton of emissions per year. These changes were requested by industry based on the argument that the existing provision was specifically designed for one particular source and is not useful for the broader industry. While sources are no longer required to meet the solvent return opening provision in order to claim the exemption, they are subject to the requirements contained in Regulation Number 7, Section X.B.

Measurement of the throughput threshold for the fuel storage and dispensing equipment APEN Exemption in Section II.D.1.ccc., was changed from a 30-day average to an annual average. In addition, language was added to clarify that sources in the Denver ozone attainment-maintenance area must still utilize Stage 1 vapor recovery on all tanks with a capacity greater than 550 gallons, as required by Regulation Number 7. While ordinarily sources subject to other applicable requirements would be precluded from taking the exemption under the APEN and constructions permit exemption catchall provisions, in this particular instance, it is the Commission's intent that sources may take this exemption providing that the Regulation Number 7 vapor recovery requirements are met.

An APEN exemption for wet screening operations was added at Section I.D.1.cccc. Certain wet screening operations are subject to New Source Performance Standard (“NSPS”) Subpart OOO. This federal requirement requires that such facilities comply with a zero visible emissions standard. Ordinarily, a source that is subject to a New Source Performance standard precludes the source from taking an APEN exemption pursuant to the catchall provision in Section II.D.4. It is the Commission's intent that in this particular case, application of NSPS Subpart OOO shall not prevent a wet screening operation from taking the exemption.

A substantive change was made to the applicable de minimis levels for APEN exemptions in attainment and nonattainment areas. Under the prior regulation, if an area was nonattainment for any pollutant the lower nonattainment de minimis levels applied for all pollutants. This has been revised so that the lower levels will only apply to the pollutants for which the area is not in attainment.

The exemption for agricultural operations was changed to provide greater clarity and to be consistent with the requirements of the State Act. Conforming changes were also made to the agricultural exemption set forth in Part C.

Because Regulation Number 3 and the Common Provisions Regulation under went contemporaneous review, the primary focus with respect to duplicative provisions was to eliminate duplications between the two regulations. Duplicative provisions that were only applicable to Regulation Number 3 were deleted from the Common Provisions Regulation. Provisions applicable to multiple regulations remain in the Common Provisions and were deleted from Regulation Number 3. Certain non-Regulation Number 3 duplications were also addressed. A full review of all the Commission's regulations was not undertaken at this time. It is expected that there are additional duplications that should be addressed as other regulations are opened for revision.

C. Fee Schedule Revisions

The language governing the fee schedule for APENs and permit processing was simplified to provide that fees will be charged in accordance with the procedures and amounts set forth in the Act. This change alleviates the requirement of revising the regulation every time the statutory fee schedules change.

D. Confidentiality Provisions

The rules governing confidentiality of documents submitted in connection with APENs and permit applications were changed to be consistent with the Act, and to clarify ambiguities in the prior regulation. In addition, more specific provisions were added regarding the process involved in asserting confidentiality and determining whether documents are in fact confidential. Under the prior regulation, the evaluation of confidentiality claims was very ambiguous making it difficult for the Division to determine whether a document was confidential, and providing sources no guidance as to the steps they should take to ensure confidential treatment of documents. The new provisions clearly set forth the rules for claiming confidentiality and for evaluating such claims. This should benefit the Division and the regulated community by providing a clear understanding of confidentiality protections.

Pursuant to the State Act, information submitted as part of an air pollutant emission notice, Permit Application or Operating Permit reports is confidential only if it relates to secret processes or methods of manufacture or production. This limitation is reflected in the revised regulation. In contrast, Section 25-7-111(4), C.R.S. provides that information obtained by the Division in connection with an enforcement action may be entitled to confidential treatment if it constitutes a trade secret. The current regulatory revision is not intended to alter or affect the protections offered under Section 25-7-111(4), C.R.S.

In cases where the Division determines that certain information is not subject to confidential treatment the revisions shorten the notification period from fifteen to three days. This change was made based on the statutory mandate in the Colorado Open Records Act requiring release of public records within three days after a request for such records. The notification period is intended to allow the source the opportunity to obtain judicial relief from the Division's determination under the State Administrative Procedures Act prior to release of the information. While it is recognized that the three-day notification period may make it difficult for a source to institute a timely action, the requirements of CORA preclude a longer period. It is expected that the Division will take the steps necessary to provide actual notice to the source as soon as a determination is made, so that the source will have adequate time to protect its rights.

II. Part B Revisions

The majority of revisions to Part B involve stylistic changes intended to improve the readability of the regulation. A small number of substantive revisions were made as described below.

The provisions in Section IV.H., were changed to clarify the requirements for obtaining a final approval construction permit. The previous regulation required the source to demonstrate compliance with the initial approval construction permit. The Division was then required to conduct an inspection to determine compliance. Because an inspection during the initial approval period is not required by law, the new regulation makes the inspection discretionary. This provides necessary protections in those instances where an inspection may be needed. The provision was further modified to give the Division discretion as to whether to issue a final approval permit when there is a pending operating permit application. Requiring the issuance of a final approval permit was often an unnecessary step in situations where an operating permit would be issued shortly thereafter. To avoid confusion among sources when the Division elects not to issue a final approval construction permit, a notice will be provided to the source in writing. Similar flexibility was added to Section III.D.6., in cases where a previously permit exempt source loses its exemption based on addition of new emission points.

The prior regulation required submission of an operation, maintenance, and record keeping plan with the construction permit application. This provision ignored the reality that such plans are difficult to provide until after the source has been constructed. The new regulation provides that these plans must be submitted prior to obtaining final approval.

Significant changes were made to the post construction monitoring requirements for the PSD program. The changes were made to be consistent with the federal PSD regulations. The revisions provide flexibility to either require or waive post-construction monitoring.

The revisions expand the provisions governing appeals of construction permits. The prior regulation provided that a source could appeal the Division's decision to the Commission, but failed to identify the process for such an appeal. The revision provides that the appeal must be made within thirty days after the issuance of the permit, denial or revocation, and will be held in accordance with the general rules for adjudicatory hearings. A similar provision was also added in Part C at Section V.E.

Section V.B. has been changed to reflect that the Black Canyon of the Gunnison has been reclassified as a National Park. The boundaries of this area remain the same, and there is no change in the classification of this area as Class I or Class II.

Revisions have been made throughout the regulation to address changes in areas from the nonattainment classification to the attainment/maintenance classification. A search of the regulation was conducted to identify those provisions that depended on the area being classified as nonattainment. When a requirement remains in place after the reclassification of an area, the word nonattainment was changed to attainment/maintenance. Otherwise, no change was made. A substantive change was made to the applicable de minimis levels for permit exemptions in attainment and nonattainment areas. Under the prior regulation, if an area was nonattainment for any pollutant the lower nonattainment de minimis levels applied for all pollutants. This has been revised so that the lower levels will only apply to the pollutants for which the area is not in attainment to be consistent with a similar revision in Part A.

III. Part C Revisions

As with Parts A and B, the majority of revisions to Part C include changes to improve readability and to clarify ambiguous provisions. Revisions were made to Section II.E., to fix poorly worded language. The new provision more clearly explains when an insignificant activity exemption can be taken. In addition, changes in II.E., and to other Sections regarding exemptions included in Part C were made to conform to exemptions in Part A and B.

Provisions regarding the phase-in of the operating permit program were deleted since these provisions are now obsolete.

Section III.B.2., sets forth certain timing requirements with respect to submitting operating permit applications. The prior regulation was unclear as to the new legal requirements for sources subject to the operating permit requirement after start-up by operation of law. The revised provision clarifies that sources shall submit an application within twelve months of the effective date of the new requirements or at such other time specified in those requirements. The revisions also clarify that when a source subject to an operating permit is modified, an application to revise the permit must be submitted within twelve months of the modification.

In the past, significant confusion has arisen when a source seeks an operating permit prior to obtaining a final approval construction permit under Part B. Revisions to Sections V.A., and IV.B.3., clarify the rules governing these situations. These revisions also conform to the changes made in Part B, Section IV.H. The flexibility given to the Division to issue an operating permit absent a final approval construction permit under Section V.A., is intended to apply regardless of whether the source has commenced operation of the emission unit(s) at issue.

IV. Appendices

Prior to this rulemaking, Regulation Number 3 included four appendices: Appendix A, Method for Determining De Minimis Levels for Non-Criteria Reportable Pollutants; Appendix B, 1993 Non-Criteria Reportable Pollutants; Appendix C, 1994 and Subsequent Years Non-Criteria Reportable Pollutants; and Appendix D, Non-Criteria Reportable Pollutants. This rulemaking deletes the original Appendix B and Appendix C because they are duplicative of Appendix D. Appendix D has been revised to Appendix B in order to maintain continuity in the regulation.

**I.EE. Adopted October 17, 2002**

**Revisions to Regulation Number 3**

This Statement of Basis, Specific Statutory Authority and Purpose comply with the requirements of the Colorado Administrative Procedure Act Sections 24-4-103(4) and (12.5), C.R.S. for new and revised regulations.

Basis

Regulation Number 3 sets forth the Air Quality Control Commission's permitting and air pollutant emission notice programs for stationary sources. Pursuant to its statutory authority, the Commission may exempt certain stationary sources from permitting and APEN requirements where emissions from such sources are deemed to be insignificant. The Commission is revising the exemptions for condensate and crude oil tanks and condensate and crude oil loading equipment to ensure that the exemptions apply only where the emissions are truly insignificant. Additionally, the Commission is revising the provisions designed to ensure that in exempting certain sources from APEN and permit requirements, the regulation does not allow sources to avoid other state and federal requirements. This revision clarifies when application of other requirements prohibit sources from claiming exemptions.

Specific Statutory Authority

The specific statutory authority for these revisions is set forth in various Sections of the Colorado Air Pollution Prevention and Control Act ("Act"). Section, 25-7-105(1), C.R.S., gives the Air Quality Control Commission authority to promulgate rules and regulations necessary for the proper implementation of the Act, including regulations to assure attainment and maintenance of national ambient air quality standards, emission control regulations and a prevention of significant deterioration program. Section, 25-7-105(12), C.R.S., provides specific authority to establish, emission notice, construction permit and operating permit programs. Some of the statutory parameters for these programs are set forth in Sections 25-7-114.1, and 25-7-114.2 of the Act, including the authority to exempt certain sources from APEN and Permitting requirements. These Sections in turn, provide additional statutory authority for the current revisions.

Purpose

I. Condensate Tanks and Truck Loading Equipment

Revisions to the crude oil and condensate storage tank exemption in Part A, Section II.D.1.ddd.and crude oil and condensate truck loading equipment exemption in Part A, Section II.D.1.ee., were proposed to address the issue of flashing emissions in condensate tanks. The exemptions, and a corresponding exemption in Part C, Section II.E.3.ee. and ddd., did not take flash emissions into account when the Commission initially adopted the exemption. The large quantity of volatile organic emissions that can be released during a flash event led to changes in the exemptions. Additionally, separate exemptions have been established for crude oil tanks and equipment and condensate tanks and equipment in recognition of the fact that flashing emissions from crude oil and condensate are significantly different.

The Commission recognizes that in changing these exemptions a number of tanks and equipment that were previously exempt from APEN reporting, and therefore exempt from construction permitting requirements, will now be required to file APENs. The Commission does not believe, however, that these existing sources will now be required to obtain state construction permits, since such a requirement is triggered by construction or modification of a source, and not by a change in a previously applicable exemption. If, however, the tanks or equipment is modified after December 30, 2002, a construction permit will be required for the modification unless the tanks or equipment qualifies under the revised APEN exemption or constructions permit exemption. During the revision process there was some discussion about what might constitute a modification that would trigger construction permit requirements. Based on the information provided to date, the Division and Commission do not currently believe that reworking of an existing well would constitute a modification under the regulations. Additionally, sources subject to PSD, NSR-NAA and Title V permitting requirements are required to have such permits regardless of their exemption status. The Commission notes to permit applicants that this change becomes effective on the effective date of this regulation.

In connection with these revisions, the Commission has also looked at the timing requirements set forth in Part A, Section II.D.1.lll., for submitting APENs and obtaining construction permits for tanks at crude oil and natural gas exploration and production sites. The Commission enacted this provision in 1993 to allow sources sufficient time to determine production levels before being required to submit APENs or construction permit applications. To affect this, Section II.D.1.lll. provided that APENs for oil and gas exploration and production operations were not required until 30 days after filing the well completion or recompletion report with the appropriate state or federal agency. Additionally, Part B, Section III.D.8. provided that applications for construction permits for such operations were due at the same time as the APEN filing. Based on discussions during the regulation revision process the Commission discovered that the well completion report must be filed before production levels can be determined and that the provision should have referenced the report of first production. Therefore, the Commission has revised Section II.D.1.lll. to clarify and effectuate the intent of the 1993 revisions.

The Commission also recognizes the definition of condensate that appears in the Common Provisions Regulation does not include reference to an API gravity and therefore could be read to include crude oil. It is the Commission's intent that for the purposes of these exemptions, as well as APEN reporting, condensate should only include hydrocarbon liquids that fit within the Common Provisions definition and that have an API gravity of 40 degrees or above. The Commission anticipates revising the Common Provisions definition to more clearly reflect this intent the next time the Common Provisions regulation is opened for revision.

II. APEN Catchall

Changes to the APEN catchall in Part A, Section II.D.4. and the construction permit catchalls in Part B, Section III.D.5., were significantly reworked to add clarity. The prior versions were somewhat unclear as to both the effect of APEN and permitting exemptions on other applicable requirements and when otherwise exempt sources would be required to file APENs. While the revisions minimally change the substantive requirements of the two catchall provisions the new language is intended to more clearly express these requirements. The new language clarifies that sources that are exempt from APEN and/or construction-permitting requirements are not, by virtue of that exemption, exempt from any other applicable requirements. Thus, for example, a source that is exempt from APEN or permitting requirements, must still comply with the Regulation Number 1 20% opacity standard. Likewise, an APEN exempt emission point at a major source is excused from paying APEN fees but may still need to be listed as an insignificant activity under the requirements of the Title V program. Additionally, where the emissions from a particular emission point would cause a source to avoid PSD, NSR-NAA or Title V information regarding that emission point cannot be omitted from any permit application, notwithstanding the fact that the emission point standing alone might be exempt from APEN or Construction Permit requirements.

The Commission also requires that if the potential to emit, taking into account full design rate and continuous operation, triggers PSD or NSR requirements, the source must submit an Air Pollutant Emission Notice and apply for the appropriate permit, or must apply for a permit to limit the physical or operational capacity of the source such that the source is not considered to be a major source as defined in Section I.B.59 of Part A of this regulation. This language previously appeared in the catchalls, but was relocated to this statement of basis.

Finally, the revised catchall provisions subject certain emission points and sources to APEN and Construction Permit requirements notwithstanding the fact that such points and sources would otherwise be exempt. Sources specifically identified in the applicability Section of any subpart of Part A of Regulation Number 6 (New Source Performance Standards), or Regulation Number 8 (Hazardous Air Pollutants), Parts A, C, D, and E. This provision allows the Division to keep track of these points and sources, and ensure that the requirements of these programs are being properly followed. It must be noted, however, that wet screening operations subject to the exemption set forth at Part A, Section II.D.1.cccc may claim exemptions notwithstanding the fact that such sources are subject to New Source Performance Standard OOO.

**I.FF. Adopted April 16, 2004**

**Revisions to Colorado Air Quality Control Commission Regulation Number 3 Stationary Source Permitting and Air Pollutant Emissions Notice Requirements**

This Statement of Basis, Specific Statutory Authority and Purpose complies with the requirements of the Colorado Administrative Procedures Act, Section 24-4-103, C.R.S., and the Colorado Air Pollution Prevention and Control Act, Sections 25-7-110 and 25-7-110.5, C.R.S.

Basis

Regulation Number 3 sets forth the Air Quality Control Commission's (“Commission”) permitting and air pollutant emission notice programs for stationary sources. The rule revisions adopted reorganize and clarify the permitting, monitoring, reporting and fee requirements of Regulation Number 3. In addition, new provisions were added to conform the state program to the federal rules.

The existing regulation was composed of four parts. Part A contained general provisions and the Air Pollution Emission Notice [APEN] program; Part B addressed major and minor source construction permits; Part C set forth the Operating Permit Program; and Part D included the statements of basis, specific statutory authority and purpose for historical revisions to the regulation.

The Commission reorganized the rule in order to make it easier for sources to find and comply with applicable requirements. Part A now contains general provisions applicable to reporting and permitting, including the Air Pollution Emission Notice requirements; Part B addresses construction permits; Part C includes the operating permit program; and Part D deals with the Nonattainment New Source Review and Prevention of Significant Deterioration [“New Source Review” or “NSR”] programs for major stationary sources. Minor sources will only be subject to Parts A and B; major sources (as defined for the Operating Permit program) are governed by Parts A, B and C. Major stationary sources must comply with Parts A, B, C and D. In particular, this reorganization separated the major stationary source NSR provisions from the construction permit requirements applicable to all sources. This will make it easier for minor sources to comply with the regulation. The Commission also made changes to each part in order to clarify ambiguous language, eliminate duplicative or unnecessary provisions, increase the level of certainty for the regulated community and make the regulation more understandable. Part E is now reserved for Environmental Management Systems and Part G contains the historical and current Statements of Basis, Specific Statutory Authority and Purpose for Commission rulemaking actions.

In addition, the changes incorporate modifications to the nonattainment new source review and prevention of significant deterioration programs. Changes to these programs were necessary to comply with federal rule revisions that must be incorporated into the Colorado State Implementation Plan ("SIP"). The Commission tailored the federal requirements to Colorado's air quality program to ensure efficient and flexible operation and administration of the program while eliminating or minimizing undue and unnecessary burdens on the regulated community.

Specific Statutory Authority

The Colorado Air Pollution Prevention and Control Act, Section 25-7-105(17), C.R.S., gives the Commission authority to promulgate regulations necessary for the proper implementation of the Act, including rules to assure attainment and maintenance of national ambient air quality standards and a prevention of significant deterioration program. Section 25-7-105(12), C.R.S, provides specific authority to establish emission notice, construction permit and operating permit programs. Some of the statutory parameters for these programs are set forth in Sections 25-7-114 through 25-7-114.7 of the Act and these Sections, in turn, provide statutory authority for the current revisions. Additional authority for these revisions is set forth in Sections 25-7-106, 25-7-119 and 25-7-132, C.R.S.

The Commission's adoption of this rule is taken pursuant to procedures set forth in Sections 25-7-105, 25-7-110 and 25-7-110.5, C.R.S.

Purpose

The Commission took into consideration the appropriate items enumerated in Section 25-7-109(1)(b), C.R.S.

General Revisions to Regulation Number 3

The Commission's reorganization of this rule separates the provisions applicable to all sources (Part A), the construction permit program (Part B) and the operating permit program (Part C). The NSR provisions for major stationary sources are now contained in Part D. In the past, these various components of the rule were intermingled to an extent that caused confusion and unnecessary work for both sources and for the Air Pollution Control Division ("Division"). By separating the major components of Regulation Number 3, the Commission intends to make the provisions more readily usable, particularly for minor sources.

As part of the reorganization, the Commission relocated some definitions. If a definition relates only to one part, it can be found at the beginning of that part. Definitions that are used in more than one part are placed in Part A. This approach will allow minor sources to identify applicable provisions without having to address the differences between construction permit, operating permit and major NSR requirements.

The Commission in this rulemaking did not amend Section V. of Part A of the existing rule. That Section addresses emissions trading and changes to it are beyond the scope of this proceeding. Likewise, the Commission specifically concluded that this rulemaking should not extend to changes to the construction-permitting program for minor sources unrelated to the federal NSR revisions; this restriction appeared in the notice of rulemaking. The Commission understands that discussions between the Division and stakeholders prompted by this proceeding may lead to policy and implementation changes.

The Commission established the effective date for the NSR revisions as the date of EPA approval of the changes as part of the Colorado SIP. An earlier effective date would have created differences between federal and state rules that could expose the regulated community to inconsistent requirements. For the remainder of the rule, the Commission concluded that the effective date need not await EPA action. Those provisions will become effective following publication in the Colorado Register.

Finally, an issue arose regarding the use of the term “attainment/maintenance” areas. Although this terminology is used in Colorado's State Implementation Plan, its relationship to these rule changes is unclear. The Commission decided to address this question at a later time.

Finally, the Commission concluded that the revisions to Regulation Number 3 do not change the procedural, administrative nature of the regulation and are not specifically intended to reduce air pollution. Accordingly, the Commission did not make the determinations addressed in Section 25-7-110.8, C.R.S., although this Statement of Basis and Purpose includes discussion to inform interested parties of the Commission's intent.

Part A Changes

Changes to Part A largely clarify or correct existing provisions. Where EPA changed specific language used in this part, the Commission adopted identical phrasing absent an identified reason for a distinction.

The term “annual actual emissions” in Section I.B.9. replaces “actual emissions” throughout Part A in references to Air Pollutant Emissions Notices (“APENs”) so that a source's reported emissions are those actually emitted during a single calendar year. This will distinguish reported emissions from the two-year average of “actual emissions” used for major NSR purposes.

Section II.D.1.g. has been modified to refer to a “major source” rather than a “major stationary source,” a term that is specific to the major NSR program. This conforms to Section 25-7-109, C.R.S.

The Commission changed Section VI.C.3 to permit sources sixty days from issuance of an invoice to pay annual emissions fees. This approach will allow sources additional time to process fee payments. In addition, the Division is required to forward any bills more than thirty days overdue to the collections office for the state. This extended payment period will reduce the number of instances in which delays in payment result in a fee bill being sent to collections.

The Commission adopted a change to the definition of “stationary source” reflected in Section Part A, Section I.B.41 to conform it to federal and state law.

Changes to Parts B and C

The Commission made only conforming changes in Parts B and C after moving the provisions applying to major NSR to Part D.

Part D Changes

Nonattainment New Source Review and Prevention of Significant Deterioration Provisions

On December 31, 2002, the Environmental Protection Agency (“EPA”) promulgated a final rule addressing the major NSR programs mandated by Parts C and D of Title I of the federal Clean Air Act. The Agency changed the requirements applicable to Colorado's SIP. The Commission adopted these revisions in order to comport Colorado's air quality program to the EPA rules. The revised regulation references to “NSR requirements” include both the nonattainment new source review and prevention of significant deterioration programs.

EPA's major NSR changes modified the method for determining whether a proposed facility modification results in a significant emissions increase, thus triggering major NSR evaluation and technology requirements. In addition, EPA added new applicability options, Plant-wide Applicability Limitations and Clean Units, and an exclusion from major modification provisions for Pollution Control Projects.

On October 27, 2003, EPA adopted further revisions to the major NSR program. In that rule, EPA provided a category of equipment replacement activities that would not be subject to the major NSR requirements under the routine maintenance, repair and replacement ("RMRR") exclusion. That rule has been challenged in U.S. Court of Appeals in Washington, D.C. The Court issued a stay, because of which the rule was not yet effective at the time of the hearing in this proceeding. The Commission elected to address RMRR issues in the future and not consider RMRR rule changes at this time.

In general, the Commission changed Part D of Regulation Number 3 to mirror the EPA major NSR rules. There are instances in which the Commission's rule differs from the federal provisions. These cases are specifically identified in this Statement of Basis and Purpose, as required by Section 25-7-110.5, C.R.S.

General

The Commission required Division review and/or approval of certain actions in instances in which the federal rule was either silent or contained no similar specific requirement. The EPA rule preamble anticipates that state minor source permit programs will continue and the Commission agreed. Colorado's Air Pollution Prevention and Control Act ("the State Act") specifically requires permits for construction and modification of air pollution sources. The Commission has historically used permits as the basic administrative structure for its stationary source programs. Exceptions to permit requirements exist in the rule for sources or activities with small emissions that have a minimal impact on air quality. In Section I.B.5., the Commission imposed a requirement that owners or operators using the actual-to-projected-actual applicability test for a project that requires a minor source permit or modification [pursuant to Part A, Section I.B.26., Part C, Section I.A.4. or Part C, Section X., or any minor source permit under any provisions of Part B], to submit an otherwise-required permit application and include documentation adequate to substantiate calculations made for the test. The federal rule requires that the owner or operator retain, but not report to the permitting authority, this information. However, the information listed in this Section would necessarily be generated by the owner or operator to satisfy the federal requirements and need only be submitted with an otherwise-necessary construction permit application. Accordingly, the Commission concluded that this requirement does not exceed federal requirements for the purposes of the Colorado Air Pollution Prevention and Control Act.

The Commission also concluded that the emissions calculated for the actual-to-projected actual test did not need to be the subject of a permit limitation. Accordingly, the information submitted will only be placed in an appendix to the major stationary source's Title V and/or in a construction permit note. This provision will assist the Division in evaluating the results of the applicability test before the relevant project is begun. Both the Division and the owner or operator will benefit from early identification of any disagreements about the applicability test.

The Commission noted discrepancies in the use in the federal rule of the terms "regulated NSR pollutant" and "regulated air pollutant." The latter includes Hazardous Air Pollutants by definition. In order to conform all of the Sections using these terms, the Commission used "regulated NSR pollutant" throughout Part D.

The federal rule allows a reviewing authority to establish a "reasonable period" for determining what constitutes a "contemporaneous" net emissions increase. Part A, Section I.B.37.b. of the old rule specified a period of five years. The Commission retained that five-year period in the revisions adopted. This period remains reasonable, just as it was under the prior version, serves to increase certainty and should assure that any net emission increase calculations are more accurate.

For calculation of Baseline Actual Emissions levels in Part D, Section II.A.4., the Commission concluded that emissions during periods of startup, shutdown and malfunction must be quantified based on the rate of operation during that period. For example, during a control equipment malfunction the calculation must assume that no controls were used to reduce emissions during that period unless the source can demonstrate the actual level of control provided during the malfunction. The Commission will allow a source to use estimation methods based on best engineering judgment, subject to approval by the Division; however, sources utilizing Continuous Emissions Monitors should be able to quantify these emissions with relative ease. In any event, the Baseline Actual Emissions calculations must be approved by the Division for use in the applicability test.

In calculating Baseline Actual Emissions, Part D, Section II.A.3., the emissions from malfunctions/upsets that exceed any enforceable limitations effective at the time of the event must be excluded. Allowing inclusion of these emissions in the calculation could reward a source for failing to limit, as much as possible, emissions during these events. Existing rules relating to these periods and “upsets” are not otherwise changed by the revisions.

The federal rule requires that emissions from “demand growth” be excluded from the Projected Actual Emissions calculation. Demand growth is any increased utilization that could have been accommodated by the source prior to any change. In no case, however, may demand growth emissions exceed an enforceable limitation existing prior to the change or modification.

The Commission elected not to elaborate on or further define some issues in the rule, instead relying on policy and practice that will be developed as necessary by the Division and/or EPA. These include what “could” increase emissions and what constitutes “regular operations” in Section VI.B.5.c. as well as the approach for evaluating “design capacity” in Section II.A.38.a. In another provision, Section VI.B.5., the Commission intends that the Division will implement the wording “reasonable possibility” consistent with, though not necessarily identical to, EPA's rule preamble and the Notice of Reconsideration issued by EPA regarding this issue. Likewise, when an owner or operator uses emission factors to monitor PAL pollutant emissions [Section V.A.7.c.(iii)], it and the Division will adjust, as appropriate, those factors to account for uncertainties or limitations inherent in the factor. The federal preamble may be consulted for guidance on such issues, including the option for the Division to exempt a source from having to validate the factors.

Sections II.A.4.a. and VI.B.5.c. include the concept of a period that is “more representative of normal source operations” in the definition of Baseline Actual Emissions. The Commission decided that such determinations will continue to be resolved on a case-by-case basis by the Division.

Plant-wide Applicability Limitations (“PAL”)

For the purpose of setting a PAL, a unit planned but not yet constructed as of the date of PAL determination has Baseline Actual Emissions of 0 tons per year, as it does not have actual emissions as of that date. These units do not differ in practice from those later planned but not yet constructed under the PAL. Both types of units must meet the emissions limitations and other conditions assessed in the PAL. Emissions units constructed at the time the PAL is set, but that have not yet operated for more than two years are new units. The Division, after consultation with EPA, recommended that the Commission not allow PALs for major stationary sources that have not been in operation for at least two years. The Commission agreed. These sources would not have “actual emissions” for this purpose because they would not yet have operated during a representative period. Allowing PALs for these sources would effectively create an “allowable PAL.” EPA clearly indicated in the December 31, 2002 preamble that it did not intend to create provisions for allowable PALs in that promulgation. The phrasing here comports with EPA's intent.

Process and control equipment changes under PALs require application and approval of a permit under existing provisions of Colorado law. PALs, since they establish a new emissions limitation for an entire facility, will necessitate a revision to the Operating Permit held by the owner or operator. The Division will act on any such permit application during the period otherwise provided in Part C. Once a source has obtained a PAL, the PAL emission limits and conditions must remain in place for the entire ten-year effective period of the PAL. Allowing a source to obtain and renounce a PAL at a shorter interval would create confusion and potentially allow manipulation of the PAL option to avoid major NSR.

The Commission adopted language differing in minor respects from the federal rule in Sections XVII.B.2. and XVII.I.2. The federal language used to construct Section XVII.B.2. was incomplete and unclear in that it did not specify that baseline actual emissions calculations must be provided for each emissions unit as parts of a PAL permit application. The phrase added creates no additional burden for sources that would have to evaluate emissions from these units in any event. In Section XVII.I.2., the Commission added the phrase “including any additional information requested by the Division.” Although the Division's authority to request information in order to confirm an owner or operator's calculations is well accepted, this addition places the PAL applicant on notice that a request may be made.

The Commission also departed from the federal wording in Section XVII.N.1. that addressed the semi-annual report to be provided by PAL sources. The Commission concluded that requiring submittal with the report of all data relied upon imposed an unnecessary and undue burden on sources. Instead, the rule allows the Division to request these data if it finds it necessary to implement its administration of the PAL permit.

Clean Units

The CU provisions of this regulation address only the emissions from a specific unit. If a unit is designated as a Clean Unit, the source does not need to go through the major source NSR program if it makes certain types of changes in the future. This allows greater flexibility to a source. The source must accept the changes to its Title V permit that are required by the rule. Additionally, an owner or operator must apply for and obtain either a Construction Permit or Operating Permit for future changes at the CU that meet the definition of modification for Part B or C purposes even though it need not evaluate the project for major source NSR applicability. The Division will act on a permit application during the period otherwise provided in Part B or C of this regulation.

Section XV.A.3. requires an owner or operator to submit a request for designation as a Clean Unit (“CU”), although this requirement does not affect automatic qualification as a CU. This provision ensures that the Division may conduct an initial, cursory review to confirm the qualification. Absent this provision, sources mistakenly using the CU option might operate for years in the belief that the designation protects operation of the unit. One principal concern for the Commission in adopting any regulation is to provide a high level of certainty for sources to avoid delayed compliance issues. By allowing the Division to review the information the source used to qualify as a CU, the Commission is providing that certainty for sources. In addition, this provision simplifies field and other inspections by assuring that the Division has an accurate record of the operations and equipment at the source.

Pollution Control Projects

The Commission believes that the Pollution Control Project ("PCP") exclusion will only be used for projects that result in a significant emissions increase in a "collateral" pollutant. If the project does not cause increases in any regulated pollutant, it would not need an exclusion from major modification requirements. Therefore, Section XVI.A. requires that a source intending to use the PCP exclusion must submit an APEN and a permit application, whether the PCP is listed or unlisted, as a significant emissions increase is likely to occur. Under the federal rule, unlisted PCPs are required to obtain permits or permit modifications. The Commission omitted the provision in the federal rule requiring a written notice for listed projects to streamline duplicative requirements in the federal PCP provisions and Parts B and C of the regulation. However, recognizing the nature of PCPs, the Commission has retained the list of the information that must be submitted to the Division. This list differs in some respects from the information required in the permit provisions of Regulation Number 3.

The Commission also adopted a provision requiring owners or operators of PCPs to retain records for a minimum of five years, consistent with the Operating Permit recordkeeping timeframe. The federal rule does not specify a retention period. This Commission action was appropriate to assure that sources and the Division have a common understanding about the retention period. Finally, in order to comply with the federal rule, the Commission included a public notice and comment opportunity for PCPs.

**I.GG. Adopted December 16, 2004**

**Revisions to Regulation Number 3**

The primary purpose of this rule revision is to clarify the applicability of various permitting and APEN provisions to sources within areas designated as attainment/maintenance. Such clarification merely makes express the rule that applied by interpretation. In most cases, the revision makes the requirements applicable to attainment areas applicable to attainment/maintenance areas. One notable exception is the requirement for construction permits for gasoline stations within the Denver 1-hour ozone attainment/maintenance area, which requirement is specified in the SIP. 40 CFR 52.320(c)(94). This rule revision also includes other minor revisions, including reporting requirements for condensate storage tanks subject to Regulation Number 3, Section XII., and corrections for accuracy. This rule revision makes no significant, substantive changes to the regulation. Nothing in this rule change exceeds the requirements of federal law. This rule change is administrative in nature, is not intended to cause reductions in air pollution, and therefore is exempt from the requirement for findings pursuant to Section 25-7-110.8, C.R.S.

**I.HH. Adopted July 21, 2005**

**Revisions to Regulation Number 3**

This Statement of Basis, Specific Statutory Authority and Purpose complies with the requirements of the Colorado Administrative Procedures Act, Section 24-4-103, C.R.S., and the Colorado Air Pollution Prevention and Control Act, Sections 25-7-110 and 25-7-110.5, C.R.S.

Basis

Regulation Number 3 sets forth the Air Quality Control Commission's permitting and air pollutant emission notice programs for stationary sources. The Commission amended Regulation Number 3, Part A, Section V. to make it consistent with the repeal of the Emissions Trading Rule in Regulation Number 5 in December 2004. It was originally anticipated that Regulation Number 5 would replace Part A, Section V. in Regulation Number 3 as the Commission's trading program, essentially identical to EPA's. The text of Part A, Section V. was italicized to represent provisions that would remain effective until EPA approved the program in Regulation Number 5. EPA decided not to finalize its trading program; therefore, it would never approve Regulation Number 5 as a SIP component. The Commission deleted Section V.A.3., Part A that contained the outmoded effective date. The Commission also replaced the italicized text with normal font in all of Part A, Section V. to conform the text to these circumstances. In addition, one hazardous air pollutant (2-butoxyethanol) was deleted to conform the State's list (in appendix b) to the Federal list of hazardous air pollutants.

The Common Provisions Regulation sets forth requirements and definitions that pertain or may pertain to all of the other Commission regulations. EPA added four compounds to its list of compounds (known as non reactive volatile organic compounds) to be excluded from the definition of volatile organic compound on the basis that these compounds make a negligible contribution to tropospheric ozone formation. The Commission adopted a conforming change to the definition of non-reactive volatile organic compounds in the Common Provisions Regulation, Section I.G.

Specific Statutory Authority

The Colorado Air Pollution Prevention and Control Act give the Commission authority to promulgate regulations necessary for the proper implementation of the act. Section 25-7-105(12), C.R.S, provides specific authority to establish emission notice, construction permit and operating permit programs. Some of the statutory parameters for these programs are set forth in Sections 25-7-114 through 25-7-114.7 of the act and these Sections, in turn, provide statutory authority for the current revisions. Additional authority for these revisions is set forth in Sections 25-7-106, 25-7-119 and 25-7-132, C.R.S.

The Commission's adoption of this rule is taken pursuant to procedures set forth in Sections 25-7-105, 25-7-110 and 25-7-110.5, C.R.S.

Purpose

The Commission took into consideration the appropriate items enumerated in Section 25-7-109(1)(b), C.R.S.

The purpose of removing the italicized text from Regulation Number3, Part A, Section V. was to prevent any ambiguity about the applicability of those provisions. Changing the font of the text does not have any regulatory impact since the provisions were already in effect and will remain in effect. Section V.A.3. was deleted because it was an outmoded provision that was only necessary if Section V. was to be replaced by Regulation Number 5. The Commission's repeal of Regulation Number 5 made that provision unnecessary. Removing the italics from Section V. also will eliminate confusion with the italicized text in Part D of Regulation Number 3.

The purpose of the deletion of one hazardous air pollutant in appendix b of Regulation Number 3 and the addition of four non-reactive volatile organic compounds to the list in Section I.G. of the Common Provisions Regulation is to conform the Commission's rules to Federal regulations. The Federal rule changes were published on November 29, 2004. If the Commission did not make these revisions, the State rules would be more restrictive than the Federal rules because these revisions serve to exempt the compounds from emission standards, monitoring, reporting and record keeping requirements.

**I.II. Adopted December 15, 2005**

**Revisions to Regulation Number 3**

This Statement of Basis, Specific Statutory Authority and Purpose complies with the requirements of the Colorado Administrative Procedures Act, Section 24-4-103, C.R.S., and the Colorado Air Pollution Prevention and Control Act, Sections 25-7-110 and 25-7-110.5, C.R.S.

Specific Statutory Authority

The Colorado Air Pollution Prevention and Control Act, Section 25-7-105, C.R.S., gives the Commission authority to promulgate regulations necessary for the proper implementation of the Act, including rules to assure attainment and maintenance of national Ambient Air Quality Standards and a prevention of significant deterioration program. Section 25-7-105(12), C.R.S. provides specific authority to establish emission notice, construction permit and operating permit programs. Some of the statutory parameters for these programs are set forth in Sections 25-7-114 through 25-7-114.7 of the Act and these Sections, in turn, provide statutory authority for the current revisions. Additional authority for these revisions is set forth in Sections 25-7-106, 25-7-119 and 25-7-132, C.R.S.

The Commission's adoption of this rule is taken pursuant to procedures and requirements set forth in Sections 25-7-105, 25-7-110 and 25-7-110.5, C.R.S.

Purpose

On December 31, 2002, the Environmental Protection Agency (“EPA”) promulgated a final rule revising the Major New Source Review [“NSR”] programs mandated by Parts C and D of Title I of the Federal Clean Air Act. EPA changed the several Federal provisions that were reflected in Colorado's SIP and in 2004 the Commission made revisions to match the new Federal Rule.

In the 2002 Rule, EPA provided several new applicability options for stationary sources. Among those options is treatment of some sources as clean units. To qualify, the source operators must employ state-of-the-art pollution control technology as a result of a major NSR determination within the last ten years, or demonstrate that control technology being employed is comparable to the best available control technology or lowest achievable emission rate. A source that qualifies as a clean unit would not have to go through a traditional NSR applicability determination if it makes certain types of changes in the future. The Commission’s 2004 Rule adopted the clean unit exemption virtually without change.

The 2002 Rule also expanded the exemption from major modifications for pollution control projects (PCPS), originally provided only to electric utility steam generating units in the 1992 WEPCO Rule. Under the 2002 Rule, collateral emissions increases resulting from a PCP at an existing unit would not be included in calculations to determine if a project involving that unit would trigger NSR.

As part of the 2002 rule, EPA allowed sources to calculate their actual and projected actual emissions to determine whether a modification will trigger NSR. If a source concludes that there is no “reasonable possibility” that emissions from a project will trigger NSR, the source is not required to keep records substantiating that calculation. However, the data and records would necessarily be generated by the owner or operator to calculate its emissions.

The Commission did not follow the Federal Rule in this regard. In Section I.B.5., the Commission imposed a requirement that owners or operators using the actual-to-projected-actual applicability test for a project that requires a minor source permit or modification [pursuant to Part A, Section I.B.26.; Part C, Section I.A.3.; or Part C, Section X.; or any minor source permit under any provisions of Part B], submit an otherwise-required permit application and include documentation adequate to substantiate calculations made for the test.

On June 24, 2005, the United States Court of Appeals for the District of Columbia Circuit issued its decision and opinion in the case of State of New York v. U. S. Environmental Protection Agency,----F.3D---- 2005 WL 1489698, 35 Envtl. L. Rep. 20,135, D.C.Cir., June 24, 2005. The court concluded that, regarding the clean unit exemption from NSR, the plain language of the Clean Air Act indicated that Congress intended to apply NSR to changes that increase actual emissions instead of potential or allowable emissions. As a result, the court vacated the clean units portions of the Federal Rule. The court also concluded that EPA lacks the authority to create pollution control project exemptions from NSR and vacated the PCP portions of both the 1992 Wepco Rule and the 2002 rule. By vacating those portions of the Federal NSR rule, the court terminated those exemptions to new source review.

In view of the court's decision, the Commission concluded that there was no basis to retain the clean unit and pollution control project provisions in Regulation no. 3. The federal rule no longer allows operators to use those provisions to determine applicability of NSR to the source and Colorado law and the Colorado State Implementation Plan should be conformed to federal law in this instance.

The D.C. Circuit court also addressed the recordkeeping and reporting requirements of the federal rule. The 2002 rule excused a source from maintaining records of the information and calculations used in the actual-to-projected actual applicability test if the source determined that there was no "reasonable possibility" that the modification would trigger NSR. These are the same records necessary to substantiate calculations made for the applicability test. The court concluded that lack of evidence, in the form of data and records, could inhibit enforceability of the NSR program in this context. The court remanded this part of the rule.

By remanding this portion of the 2002 rule, the court allowed EPA to further consider its position and return to the court at some time in the future for more proceedings in support of the rule. In this case, EPA has the opportunity to explain how it can ensure NSR compliance without the relevant data. There is no deadline, or requirement, for EPA to take further action.

The Commission, in its 2004 rulemaking, elected to require that sources retain records that, among other things, are essential to substantiate sources' calculations using the actual-to-projected-actual applicability test. The Commission also chose to require that a source submit its data and calculations along with a permit application that would otherwise be required for the physical or operational change. The Division reviews the data and calculations only to confirm a source's conclusions whether it triggers NSR. The information submitted is then included in a non-enforceable appendix to a source's Title V Permit or as a permit note in the source's construction permit

The recordkeeping requirement adopted by the Commission has benefits to both sources and the Division, one of which is to avoid later uncertainty whether a project triggered NSR. Accordingly, the Commission elected not to modify this part of Regulation Number 3.

The recordkeeping requirement adopted by the Commission has benefits to both sources and the Division, one of which is to avoid later uncertainty whether a project triggered NSR. Accordingly, the Commission elected not to modify Part D, Section I.B.5. and to modify Part D, Sections V.A.7.c. and VI.B.5. in a manner, that maintains consistency with Section I.B.5.

**I.JJ. Adopted March 16, 2006**

**Revisions to Regulation Number 3, Part F, Best Available Retrofit Technology**

This Statement of Basis, Specific Statutory Authority and Purpose complies with the requirements of the Colorado Administrative Procedures Act, § 24-4-103, C.R.S., and the Colorado Air Pollution Prevention and Control Act, § § 25-7-110 and 25-7-110.5, C.R.S ("the Act").

Specific Statutory Authority

The Commission promulgates this regulation pursuant to the authority granted in C.R.S., Sections 25-7-105 (general authorities and duties of the Commission for air quality control); 25-7-105(1)(c), (authority to adopt a prevention of significant deterioration program); 25-7-106 (additional authorities of the Commission for air quality control); 25-7-106(1) (authority to exercise flexibility in developing effective air quality control program); 25-7-106(2) (authority to hold public hearings); 25-7-109(1)(a) (authority to require the use of air pollution controls); 25-7-109(2)(a) (authority to adopt emission control regulations pertaining to visible pollutants); 25-7-114.4(1) (authority to adopt rules for the administration of permits); 25-5-114.5 (authority to require permit applications and make determinations, and to provide for public participation), and 25-7- 1002 (authority to maintain a program that complies with the requirements of the Federal act for prevention and remediation of significant deterioration of visibility in class I Federal areas).

Basis and Purpose

On July 1, 1999, the U.S. Environmental Protection Agency promulgated final regulations that require each state to submit a State Implementation Plan (SIP) to address regional haze. Those regulations require the State to establish a mechanism to identify sources that must analyze installation of Best Available Retrofit Technology (BART) and to require those analyses and implementation of resulting determinations.

The process begins with defining air pollution facilities that are “BART-eligible.” Among the BART-eligible sources, some sources are “subject to BART.” Sources that are subject to BART must complete an analysis and submit a proposal for determination by the State of the Best Available Retrofit Technology applicable to that source. This regulation establishes the mechanisms for this process. In many instances, the regulation matches the Federal BART rule, including provision for a BART-Alternative approach that would yield “better than BART” results.

The Commission elected to assume that all BART-eligible sources are subject to BART, but require the Division to perform modeling to determine whether BART eligible sources will cause or contribute to visibility impairment in any class I area. BART-eligible sources that do not cause or contribute to visibility impairment in any class I area would not be subject to BART. Individual sources would also have the opportunity to demonstrate that they are not eligible or not subject to BART. This approach will provide information necessary to develop the regional haze SIP on the schedule required by Federal law and allows for challenges to decisions on whether individual sources must complete BART analyses and to BART determinations by the State.

Sources subject to BART must evaluate all technologies through a five step case-by-case BART analysis. The five steps require sources to: 1) Identify All Available Retrofit Control Technologies; 2) Eliminate Technically Infeasible Options; 3) Evaluate Control Effectiveness of Remaining Control Technologies, 4) Evaluate Impacts and Document the Results and 5) Evaluate Visibility Impacts. The Commission intends that sources conducting a case-by-case analysis will follow EPA’s Appendix Y to 40 CFR, Part 51 – Guidelines for BART Determinations under the Regional Haze Rule. Sources must evaluate the visibility impacts of each technology option using CALPUFF and/or Division-approved modeling protocols.

This rule requires a source subject to BART to file an application for a construction permit as the mechanism for submitting its BART analysis and proposal, and for seeking a Division determination of BART for the source. The Commission concluded that using the existing permitting mechanism was the most expedient way to present the analysis for Division determination. The Commission further determined that applications for BART determinations should be subject to the public comment process applicable to construction permit applications for new or modified major sources.

When identifying the available retrofit control technologies, sources must include appropriate BACT, LAER, NSPS, Pollution Prevention (P2) and other controls used by similar sources. This can include new control technologies that are in the development stages of licensing and commercial demonstration or commercial sales. Where EPA has already conducted extensive analyses for a source category (e.g., EGUs) in relation to the Federal BART Rule and determined that certain control technology would not be required under the pertinent BART analyses, the Commission intends that a Colorado source subject to BART may adequately demonstrate that the same technology excluded under the EPA analyses would not be appropriate for the Colorado source by showing sufficient similarity between the source evaluated by EPA and the Colorado source.

Sources that identify specific options as technically infeasible must show to the Division's satisfaction that the technology is not commercially available or that specific physical or chemical characteristics of the unit(s) or emission(s) involved will not allow the technology to operate effectively.

The control effectiveness of any technology must be evaluated based on the highest removal efficiency available for the technology. Sources may also look at lower efficiencies in addition, but must include consideration of the best removal efficiency. If a source has existing controls in place, improvements to the existing controls or running the existing controls at a higher efficiency must be included in the analysis.

The Commission realizes that emission controls often have secondary impacts. Sources must evaluate the costs of compliance including the average cost effectiveness and the incremental cost effectiveness of each technology that is feasible for the source. Energy impacts including the direct energy consumption for each technology and any locally scarce fuels must be evaluated. Many control options have secondary impacts on other media. Sources must evaluate any increases in hazardous waste, wastewater, or other waste products, including increased usage of scarce resources such as water. In cases where a facility has a limited remaining operating life, the source can place a federally enforceable shutdown date in its operating permit.

The Commission intends that the Division use EPA's presumptive limits as guidelines when evaluating the BART analyses, with the understanding that there is a strong presumption that power plants capable of generating 750 megawatts or greater will meet these limits or do better, while the coal-fired electric generating units at smaller plants need to consider the presumptive limits as part of the BART analysis. Further, if a source submits an analysis demonstrating that it will meet the presumptive limits, then the source will be presumed to have met the BART-analysis requirements, absent an adequate showing to the contrary. If a source proposes a BART limit that exceeds EPA's presumptive limits, the Division would determine whether the BART analysis sufficiently supports the higher limit or whether other controls or increased control efficiencies are feasible. The Commission intends that the Division would establish a BART limit higher than the presumptive limit if supported by the BART analysis.

The Federal rules require the State to submit a SIP that identifies BART-eligible sources in the State, and requires the State to either adopt BART controls or adopt a BART Alternative. In some respects, the approach in the proposed State rule to applying the requirements of the Federal Act is not specifically mandated by the Federal rule, but left to the discretion of the State. The Federal Act does not specify the administrative decision-making process that will be used to make the relevant BART determinations. The State rule establishes such a procedure, relying on existing permitting procedures to the extent possible and appropriate. The procedure established by the State rule affords sources an opportunity for a hearing on the relevant BART decisions. This process is consistent with permitting practices and otherwise not more stringent than Federal requirements.

NOx emissions from coal-fired power plants vary considerably depending on the design of the boiler, the type of combustion controls and the type of coal used. Each of these factors has an impact on the BART analysis. In setting presumptive BART limits for NOx, EPA took into account available types of combustion control equipment, the differences between boiler types, and ranks of coal (bituminous, sub-bituminous and lignite), thereby indicating these factors should be a part of BART analyses—not solely for large power plants subject to the presumptive levels for NOx, but for all coal-fired power plants. These NOx-related characteristics should be taken into account in setting BART limits. The BART guidelines allow states to take these characteristics into account and it is the intent of the Commission that the Division should evaluate this issue as part of BART analyses. Consistent with the Federal BART Guidelines, BART determinations should take into account possible local economic disruption and unemployment that might result from adverse impacts on coal sales related to BART determinations.

In consideration of the unusual number of significant and complex permit determinations under the BART rule that will be become open to public comment about the same time, the Commission intends that the Division consider reasonable flexibility in applying procedures and time periods for public comment. The Commission also intends that all agreements and BART alternatives be noticed together with the construction permit for public comment purposes.

The Air Quality Control Commission expects that the Division will provide the information required by 40 CFR 51.308.(d)(1) and (2) for the July 20,2006 regular monthly meeting of the Commission.

**I.KK. Adopted August 17, 2006**

**Revisions to Regulation Number 3**

This Statement of Basis, Specific Statutory Authority and Purpose complies with the requirements of the Colorado Administrative Procedures Act, Section 24-4-103, C.R.S., and the Colorado Air Pollution Prevention and Control Act, Sections 25-7-110 and 25-7-110.5, C.R.S.

Basis

In accordance with the 1990 Amendments to the Federal Clean Air Act, the U.S. Environmental Protection Agency (EPA) has approved incorporation of the provisions for the New Source Review and Prevention of Significant Deterioration programs (collectively referred to as “NSR” ) into Colorado’s state implementation plan (SIP). In June 2005, the Governor submitted revisions to Colorado’s NSR program to EPA Region VIII for review and approval. During review of the submittal, Region VIII identified minor issues with provisions in Regulation Number 3 that the Commission is correcting to ensure continuing federal approval of Colorado’s NSR program. The Commission is also adopting language to treat nitrogen oxides as an ozone precursor, consistent with EPA’s promulgation of corresponding language on November 29, 2005.

Section 112 of the Clean Air Act requires EPA to maintain a list of hazardous air pollutants (HAPs) subject to regulation under that Section. EPA occasionally revises the list by adding or removing pollutants based on updated scientific evidence of health impacts. EPA removed methyl ethyl ketone (MEK) from the list on December 19, 2005. Therefore, the Commission is removing MEK from the list of HAPs in Regulation Number 3, Part A, Appendix B.

On November 29, 2004, EPA revised the federal definition of volatile organic compounds (VOCs) to specifically treat tertiary butyl (t-butyl) acetate as a VOC only for certain purposes, including reporting and photochemical dispersion modeling. The Commission is making corresponding changes to the definition of VOCs in the Common Provisions Regulation, and is adding t-butyl acetate as a non-criteria reportable pollutant in Regulation Number 3, Part A, Appendix B. Sources of t-butyl acetate will be required to report the pollutant separately from their VOC emissions on an Air Pollutant Emission Notice, and should not count their t-butyl acetate emissions when evaluating compliance with applicable VOC emission limitations. The Division should combine VOC emissions and reported t-butyl acetate emissions when conducting dispersion modeling for sources of t-butyl acetate.

The Commission is also correcting several regulatory reference errors in Parts A, C, and D.

Specific Statutory Authority

The Colorado Air Pollution Prevention and Control Act, Section 25-7-105, C.R.S., gives the Commission authority to promulgate regulations necessary for the proper implementation of the Act, including rules to assure attainment and maintenance of national Ambient Air Quality Standards and a prevention of significant deterioration program. Section 25-7-105(12), C.R.S. provides specific authority to establish emission notice, construction permit and operating permit programs. Some of the statutory parameters for these programs are set forth in Sections 25-7-114 through 25-7-114.7 of the Act and these Sections, in turn, provide statutory authority for the current revisions. Additional authority for these revisions is set forth in Sections 25-7-106, 25-7-119 and 25-7-132, C.R.S.

The Commission's adoption of this rule is taken pursuant to procedures and requirements set forth in Sections 25-7-105, 25-7-110 and 25-7-110.5, C.R.S.

Purpose

The Commission is revising Regulation Number 3 to address issues identified by the U.S. Environmental Protection Agency (EPA) during review of Colorado's state implementation plan (SIP) in 2005, to incorporate federal changes to the New Source Review program, to revise the definition of volatile organic compounds and the list of hazardous air pollutants consistent with federal actions, and to make miscellaneous technical corrections. These changes will help to ensure continued approval by EPA of Colorado's New Source Review program and will provide consistent treatment by EPA and the Division of hazardous air pollutants and volatile organic compounds. These changes will also correct regulatory cross-references within Regulation Number 3, which will make the regulation easier to understand. Further, these revisions include any typographical errors within the regulation.

**I.LL. Adopted December 15, 2006**

**Revisions to Regulation Number 3, Part A, Section VI.D.1.**

This Statement of Basis, Specific Statutory Authority and Purpose complies with the requirements of the Colorado Administrative Procedure Act Sections 24-4-103(4), C.R.S. for new and revised regulations.

Basis

The Air Quality Control Commission has adopted revisions to Part A, Section VI.D.1. in order to increase the annual emission fees charged to air pollution sources in Colorado commencing in 2007. The revised fees are within the statutory limit set by Section 25-7-114.7, C.R.S. The increase is necessary to address decreasing fee revenues used to fund existing programs, as well as to provide additional funding for requested additional permitting and inspection personnel. The proposed increase was addressed at length during a subcommittee process involving the Commission, the Division, stakeholders and other interested parties. The revision is a collaborative effort of the Division and interested stakeholders.

Specific Statutory Authority

The specific statutory authority for these revisions is set forth in Sections 25-7-114.7 of the Colorado Air Pollution Prevention and Control Act ("Act"), which allows the Commission to set annual emission fees for regulated and hazardous air pollutants.

Purpose

The revisions to Part A, Section VI.D.1. were adopted to cover anticipated revenue shortfalls and fund requested additional FTE that will be used to address the Division's permitting backlog and the increased workload arising from the rapid growth of oil and gas sources in Colorado.

**I.MM. Adopted October 18, 2007**

**Revisions to Regulation Number 3, Part A, Section VI.D.1.**

This Statement of Basis, Specific Statutory Authority and Purpose complies with the requirements of the Colorado Administrative Procedure Act Sections 24-4-103(4), C.R.S. for new and revised regulations.

Basis

The Air Quality Control Commission has adopted revisions to Part A, Section VI.D.1. in order to increase the annual emission fees charged to air pollution sources in Colorado commencing in 2007. The revised fees are at the statutory limit set by Section 25-7-114.7, C.R.S. The increase is necessary to address decreasing fee revenues used to fund existing programs. These revisions are concurrent with other recent fee adjustments to ensure appropriate funding for the program.

Specific Statutory Authority

The specific statutory authority for these revisions is set forth in Sections 25-7-114.7 of the Colorado Air Pollution Prevention and Control Act ("Act"), which allows the Commission to set annual emission fees for regulated and hazardous air pollutants.

Purpose

The revisions to Part A, Section VI.D.1. were adopted to cover anticipated revenue shortfalls and fund requested additional FTE that will be used to address the Division's permitting backlog and the increased workload arising from the rapid growth of oil and gas sources in Colorado.

**I.NN. Adopted December 21, 2007**

**Revisions to Regulation Number 3, Part E, Best Available Retrofit Technology**

This Statement of Basis, Specific Statutory Authority and Purpose complies with the requirements of the Colorado Administrative Procedures Act, § 24-4-103, C.R.S., and the Colorado Air Pollution Prevention and Control Act, § § 25-7-110 and 25-7-110.5, C.R.S ("the Act").

Specific Statutory Authority

The Commission promulgates this regulation pursuant to the authority granted in Sections 25-7-105(1)(c), C.R.S. (authority to adopt a prevention of significant deterioration program); 25-7-109(1)(a) (authority to require the use of air pollution controls); 25-7-109(2)(a) (authority to adopt emission control regulations pertaining to visible pollutants); 25-7-114.4(1) (authority to adopt rules for the administration of permits); and 25-7-1002 (authority to maintain a program that complies with the requirements of the federal act for prevention and remediation of significant deterioration of visibility in class I federal areas).

Basis and Purpose

This regulatory change places the Division's BART determinations and associated requirements in a new section of Regulation Number 3, Part E - Section VI.

EPA has raised concerns regarding the practical enforceability of the Colorado's BART determinations. The emission limits and averaging times for each of Colorado's BART sources will be included in each Title V permit, and included in the proposed SIP. The Title V permits and the SIP are each federally enforceable when approved by EPA. Nonetheless, EPA believes that more is needed to ensure the practical enforceability of these BART limits.

To address EPA's concerns the BART emission limits and related provisions concerning the installation, operation and maintenance of BART controls have also been added to Regulation Number3, and new Section VI will become part of Colorado's SIP.

The foregoing approach is largely similar to the approach taken on the state's PM-10 SIP in 2001, where the state agreed to include certain emission limits in Regulation Number 1.

**I.OO. Adopted February 21, 2008**

**Revisions to Regulation Number 3**

This Statement of Basis, Specific Statutory Authority and Purpose complies with the requirements of the Colorado Administrative Procedure Act Sections 24-4-103(4), C.R.S. for new and revised regulations.

Basis and Purpose

The Colorado Air Quality Control Commission ("Commission") intends to revise the provisions of Regulation Number 3, Part A and B to include PM2.5 as a Colorado regulated pollutant, to address inadvertent removals of rule revisions previously adopted by the Commission, and finally to correct typographical, grammatical and formatting errors found throughout Regulation Number 3.

Regarding PM2.5 emissions, the EPA promulgated a revised national ambient air quality standard ("NAAQS") for PM2.5 emissions on October 17, 2006. The effective date for the new standard was December 18, 2006. The Commission intends to apply the Regulation Number 3 requirements to PM2.5 emissions.

Additionally, the Commission intends to reinstate several previously adopted revisions and to correct several typographical errors in Regulation Number 3.

Note that the Commission intends to defer any decision to exclude ethanol production facilities from the major stationary source definition of "chemical process plant" as proposed in the Federal Register on May 1, 2007 [see *72FR24060*] until all relevant pending matters at the federal level are resolved.

**PM2.5 Emissions**

The Commission intends to apply the Regulation Number 3, Part A and B requirements to PM2.5 emissions by 1) including PM2.5 emissions under the "air pollutant" and "criteria pollutant" definitions found in Part A, Sections I.B.6 and I.B.16, and 2) setting permitting thresholds as the same level as PM10 emissions (revise Part B, Sections II.D.2 and II.D.3). Note that the EPA has not yet promulgated the PM2.5 New Source Review ("NSR") Implementation Rule, which will specify how PM2.5 emissions should be treated for Prevention of Significant Deterioration ("PSD") and major source NSR sources. Upon promulgation, the Commission intends to incorporate those changes into Regulation Number 3, Part D as well.

**Inadvertent Removals of Rule Revisions**

Several previously adopted rule revisions were discovered as having been inadvertently removed from Regulation Number 3. The Commission intends to reinstate these previously adopted revisions.

Specifically, the Commission intends to:

Re-identify volatile organic compounds ("VOCs") as being subject to the Reasonably Available Control Technology ("RACT") requirements. During the December 16, 2004 Regulation Number 3 rulemaking, VOCs were inadvertently removed from the RACT requirements. Since the minor source RACT requirement for VOC emissions were part of the State Implementation Plan, EPA considers removal of VOCs from minor source RACT requirements as backsliding. Therefore this revision should be reinserted into Regulation Number 3, Part B, Section III.D.2.

Re-insert the inadvertent removal of the following text previously adopted by the Commission on December 16, 2004:

Reference to "attainment/maintenance" areas in Part B, Sections II.D.1.c.(iii)(B), III.B.5.d., and III.C.1.a., and

Remove exemption reference to Denver Metropolitan PM10 attainment/maintenance area and change reference to "Denver Metropolitan PM10 and ozone attainment/maintenance area" to "Denver 1-hour ozone attainment/maintenance area" in Part B, Section II.D.1.f.

**Typographical, Grammatical and Formatting Errors**

The Commission intends to correct several specific typographical errors in Regulation Number 3.

Specifically, the Commission intends to:

Revise "citric acid plants" to "nitric acid plants" in Part A, Section I.B.23.b.(ix), and

Revise incorrect citation in Part B, Section I.A.

In addition, the Commission intends to correct grammatical and formatting errors in Regulation Number 3.

Specific Statutory Authority

The Colorado Air Pollution Prevention and Control Act, Section 25-7-105, C.R.S., gives the Commission authority to promulgate regulations necessary for the proper implementation of the Act, including rules to assure attainment and maintenance of the NAAQS and a PSD program. Section 25-7-105(12), C.R.S. provides specific authority to establish emission notice, construction permit and operating permit programs. Key statutory parameters for these programs are set forth in Sections 25-7-114 through 25-7-114.7 of the Act and provide statutory authority for the current revisions. Additional authority for these revisions is set forth in Sections 25-7-106, 25-7-119 and 25-7-132, C.R.S.

The Commission's adoption of this rule is taken pursuant to procedures and requirements set forth in Sections 25-7-105, 25-7-110 and 25-7-110.5, C.R.S.

**I.PP. Adopted May 14, 2008**

**Revisions to Regulation Number 3, Part F**

This Statement of Basis, Specific Statutory Authority and Purpose complies with the requirements of the Colorado Administrative Procedures Act, § 24-4-103, C.R.S., and the Colorado Air Pollution Prevention and Control Act, § § 25-7-110 and 25-7-110.5, C.R.S ("the Act").

Specific Statutory Authority

The Commission promulgates this regulation pursuant to the authority granted in Sections 25-7-105(1)(c), C.R.S. (authority to adopt a prevention of significant deterioration program); 25-7-109(1)(a) (authority to require the use of air pollution controls); 25-7-109(2)(a) (authority to adopt emission control regulations pertaining to visible pollutants); 25-7-114.4(1) (authority to adopt rules for the administration of permits); and 25-7-1002 (authority to maintain a program that complies with the requirements of the federal act for prevention and remediation of significant deterioration of visibility in Class I federal areas).

Basis and Purpose

The original language in Section IV.B established that the Division could not require post combustion NOx controls for any BART source. The Division has reviewed the data available on post combustion NOx controls in the EPA BART regulation and requested that the Commission narrowly modify the exclusion of post combustion NOx control. The EPA BART regulation investigated post combustion NOx control for Electric Utility Generators (EGUs) and generally determined that post combustion NOx control was only necessary in limited cases. The Commission believes that this analysis should be extended to boilers, as they are similar types of equipment. The Commission does not believe that the analysis done by EPA in the BART rule can be extended to cement production because of the dissimilar nature of the overall process of operation between boilers and cement kilns. The Commission narrowly modifies the provisions regarding the analysis of post combustion NOx controls as it relates to non-EGUs and non-boilers. The Commission believes this narrow amendment to Regulation Number 3 is appropriate and supported by the evidence in the hearing record.

**I.QQ. Adopted September 18, 2008**

**Revisions to Regulation Number 3, Part A**

This Statement of Basis, Specific Statutory Authority and Purpose complies with the requirements of the Colorado Administrative Procedures Act, § 24-4-103(4), C.R.S., for new and revised regulations.

Basis

The Air Quality Control Commission has adopted revisions to Part A, Section VI.D.1. in order to increase the annual emission fees charged to air pollution sources in Colorado commencing in 2008. The revised fees are at the statutory limit set by Section 25-7-114.7, C.R.S. The proposal increases the fees to the levels enacted by the General Assembly, and signed by the Governor, in SB08-055, reflected in Section 25-7-114.7, C.R.S. as amended.

Specific Statutory Authority

The specific statutory authority for these revisions is set forth in Sections 25-7-114.7 of the Colorado Air Pollution Prevention and Control Act ("Act"), which allows the Commission to set annual emission fees for regulated and hazardous air pollutants.

Purpose

The revisions to Part A, Section VI.D.1. were adopted to provide necessary revenue for existing and anticipated revenue shortfalls, and fund additional legislatively-authorized FTE and legislatively-directed air quality monitoring.

**I.RR. Adopted December 12, 2008**

**Revisions to Regulation Number 3, Part A, B and C**

This Statement of Basis, Specific Statutory Authority and Purpose complies with the requirements of the Colorado Administrative Procedure Act Sections 24-4-103(4), C.R.S. for new and revised regulations.

Basis

As of November 20, 2007, the EPA's deferral of a nonattainment designation for the 8-Hour Ozone Nonattainment Area expired, signifying that the area is now considered nonattainment, or in violation of the 1997 8-Hour Ozone NAAQS of 0.08 parts per million (ppm) for ground level ozone. This area is now known as the Denver Metro Area/North Front Range Nonattainment (DMA/NFR) Nonattainment Area. The DMA/NRF Nonattainment Area includes all of Adams, Arapahoe, Boulder, Broomfield, Denver, Douglas, and Jefferson Counties as well as portions of Larimer and Weld Counties.

Pursuant to the Federal Clean Air Act, Colorado must prepare and submit a State Implementation Plan (SIP) to the EPA no later than by June 30, 2009. This plan must propose measures designed to reduce ground level ozone precursor pollutants. The plan must provide for reductions in these precursor pollutants sufficient to ensure that ozone is reduced to below the 8-Hour Ozone NAAQS no later than 2010. If Colorado fails to submit a sufficient SIP by the aforementioned deadline, the Clean Air Act mandates that the U.S.E.P.A. prepare and implement a Federal Implementation Plan in Colorado.

Pursuant to C.R.S. § 25-7-105(1)(a)(I), the Commission must adopt such measures as are necessary to ensure compliance with the NAAQS. The Commission has adopted these rules to carry out this mandate. Specifically, the Commission has adopted revisions to Regulation Number 3, Parts A, B and C to address ozone formation in the DMA/NFR Nonattainment Area. Specifically, the Commission has adopted revisions to reduce an ozone precursor, volatile organic compound (VOC) emissions, and thus reduce ozone formation. These revisions are necessary to ensure attainment of the current 8-Hour Ozone NAAQS set at 0.08 ppm. Also, these revisions help Colorado make progress toward eventual compliance with the new ozone NAAQS set at 0.075 ppm as well as the Governor's directive to proactively and pragmatically reduce ozone levels.

Photochemical grid dispersion modeling indicates that without further emission controls, Colorado will attain the 8-hour standard by 2010. The dispersion modeling reflects that Colorado would attain the standard by a narrow margin – within 0.001 ppm on a standard of 0.08 ppm. Photochemical dispersion modeling analysis is the primary tool used to assess present and future qir qulaity trends, and is requried for EPA to approve the state attainment demonstration in the SIP. Dispersion modeling results have an inherent level of uncertainty, as recognized in EPA guidance, and it is appropriate for a state to use other tools at its disposal, including further control measures, to address and mitigate any uncertainties that can be present in dispersion modeling. It is appropriate for the state to use such tools to increase the confidence in and otherwise ensure that the predicted modeling results are accurate and borne-out in future air qulaity monitoring demonstrating attainent with the 8-Hour Ozone NAAQS.

In addition, pursuant to EPA guidance, if modeling results indicate that the highest ozone levels will fall between 0.082 and 0.087 ppm, Colorado must conduct a "weight of the evidence" analysis and other supplemental analysis in order to corroborate the modeling results. Colorado's model results are within this range, and thus the state has conducted this analysis. The analysis supports the conclusion that Colorado will attain the standard by 2010, although by a narrow margin. To encrease the certainty of the model results and the weight of evidence demonstration, the Commission concludes that these additional control measures are necessary to carry out its mandate to adopt a SIP that contains those elements that are necessary to assure attainment of the 8-Hour Ozone NAAQS.

In order to maintain consistancy between state regulations and federally enforceable regulations contained in the SIP, specifically changes to the exemptions, the Commission intends these revisions be adopted into the SIP.

Statutory Authority

The statutory authority for these revisions is set forth in the Colorado Air Pollution Prevention and Control Act ("Act"), C.R.S.§ 25-7-101, et seq., specifically, C.R.S. §25-7-105(1)(a) (authorizing a comprehensive state implementation plan which will assure attainment and maintenance of the NAAQS), 105(12) (authorizing rules necessary to implement the provisions of the emission notice and construction permit programs and the minimum elements of the operating permit program), 109(1)(a), (2) and (3) (authorizing rules requiring effective practical air pollution controls for significant sources and categories of sources, including rules pertaining to nitrogen oxides and hydrocarbons, photochemical substances, as well as rules pertaining to the storage and transfer of petroleum products and any other VOCs) and § 25-7-301 (authorizing the development of a program for the attainment and maintenance of the NAAQS).

Purpose

These revisions to Regulation Number 3 are part of an overall ozone reduction strategy to be incorporated into Colorado's SIP for ozone. The Commission intends that this overall ozone reduction strategy accomplishes five objectives: A) reduce VOC and nitrogen oxides' (NOx) emissions from oil and gas operations in the ozone nonattainment area, B) revise the control requirements for condensate tanks by transitioning from a system-wide to an emissions threshold control strategy in the ozone nonattainment area, C) expand VOC RACT requirements such that all ozone nonattainment areas are subject to Regulation 7's RACT requirements, D) clarify how the RACT requirements in Regulations 3 and 7 interact in the ozone nonattainment area, E) improve the Division's inventory of specific source category emissions state-wide; and F) make typographical, grammatical and formatting changes for greater clarity and readability.

The Commission is adopting revisions to Part A to eliminate exemptions for certain facilities from air pollution emission notice requirements. These facilities include:

- Petroleum industry flares less than 5 tons per year (tpy) emissions,
- Specified crude oil truck loading equipment,
- Oil/gas production wastewater
- Crude oil storage tanks,
- Surface water storage impoundment, and
- Condensate tanks with production 730 BBL/year or less.

The Commission is also adopting revisions to Part B to exempt the following facilities from construction permit requirements:

- Petroleum industry flares less than 5 tons per year (tpy) emissions,
- Specified crude oil truck loading equipment,
- Oil/gas production wastewater, except for commercial wastewater processing facilities, and
- Specified crude oil storage tanks.

The Commission is adopting revisions to Part C to clarify that the chemical storage tank exemption and surface water storage impoundment exemptions do not apply to specified production wastewater.

In support of objectives A and E above, the Commission adopts these revisions to Regulation Number 3, Parts A, B and C to revise APEN reporting exemptions for specific source categories (Regulation Number 3, Part A, Section II.D., Part B, Section II.D., and Part C, Section II.E.).

Improve Emissions Inventory

The Commission is changing several categorical APEN reporting and/or permitting exemptions in Regulation Number 3, Parts A, B and C in order to improve the Division's emissions inventory and for the sake of equity. These changes fall in three categories: 1) specific APEN and permitting exemptions were removed altogether; 2) specific APEN exemptions were removed and permit exemptions were kept in place; and 3) specific APEN and permit exemptions were clarified, but kept in place.

Remove APEN and Permitting Exemptions

The Commission has eliminated the APEN exemption for condensate tanks because the exemption was based on an emission level used in attainment areas. The Division will now be able to develop a complete inventory of condensate tanks and their emissions.

Condensate tanks are now subject to the same APEN requirements as other source categories in the 8-Hour Ozone Nonattainment Area. Additionally, the condensate tank exemption is based on a standardized emission factor, 13.7 pounds of VOC emissions per barrel of production, which may not be representative of each natural gas field. Even though the exemption was removed sources may still make use of the generic APEN exemption, upon determining that actual annual uncontrolled emissions fall below the applicable de minimis levels identified in Regulation Number 3, Part A. If based on this generic exemption, a source is determined to be APEN exempt, the source is also permit exempt.

Remove APEN Exemptions, Keep Permit Exemptions

The Commission has removed specific source category APEN exemptions for petroleum industry flares, crude oil truck loading, oil production wastewater and crude oil storage tanks to improve the inventory of actual uncontrolled emissions. Sources may still use the generic APEN exemption, upon determining that actual annual uncontrolled emissions fall below the applicable de minimis levels. The Commission is maintaining current permitting exemptions until such time that the APEN data justify the need for permitting activities.

Revise APEN and/or Permitting Exemptions

Similarly, based on the Division's experience, actual emissions from several source categories specific to oil and gas-related operations may be higher than previously believed. Thus the APEN and permitting exemptions for surface water impoundments (Regulation Number 3, Part A, Section II.D.1.uuu. and Part C, Section II.E.3.yyy.) were revised to exclude from the exemption, oil and gas production wastewater (similar to Regulation Number 3, Part A, Section II.D.1.uu.). Also, the APEN and permitting exemptions for chemical storage tanks (Regulation Number 3, Part C, Section II.E.3.n.) were revised to exclude oil and gas production wastewater or commercial facilities' operations (similar to Regulation Number 3, Part A, Section II.D.1.uuu. and Part C, Section II.E.3.yyy.).

Finally, the APEN and permitting exemptions for fuel storage dispensing (Regulation Number 3, Part A, Section II.D.1.cccc. and Part C, Section II.E.3.cccc.) were revised to expand the applicability of the current exemption from specifically the 1-Hour Ozone Nonattainment or Attainment/Maintenance Area to any ozone nonattainment area for the sake of equity.

**I.SS. Adopted December 19, 2008**

**Revisions to Regulation Number 3, Part F**

This Statement of Basis, Specific Statutory Authority and Purpose complies with the requirements of the Colorado Administrative Procedure Act Sections 24-4-103, C.R.S. and the Colorado Air Pollution Prevention and Control Act Sections 25-7-110 and 25-7-110.5, C.R.S. ("the Act").

Specific Statutory Authority

The Commission promulgates this regulation pursuant to the authority granted in Sections 25-7-105(1)(c), C.R.S. (authority to adopt a prevention of significant deterioration program); 25-7-109(1)(a) (authority to require the use of air pollution controls); 25-7-109(2)(a) (authority to adopt emission control regulations pertaining to visible pollutants); 25-7-114.4(1) (authority to adopt rules for the administration of permits); and 25-7-1002(authority to maintain a program that complies with the requirements of the federal act for prevention and remediation of significant deterioration of visibility in Class I federal areas.

Basis and Purpose

This regulatory change updates the Division's BART determinations by adding determinations for Colorado Springs Utilities Drake Units 5, 6, and 7 and CEMEX Portland cement facility regarding limits and averaging times for sulfur dioxide, nitrogen oxides and particulates.

The proposed change provides state and federally enforceable limitations for the BART sources. States must ensure that "each source subject to BART maintain the control equipment required by this subpart and establish procedures to ensure such equipment is properly operated and maintained" . 40 CFR 51.308(e)(v). This is required for SIP approval.

**I.TT. Adopted October 21, 2010**

**Revisions to Parts A, B, C and D to Address Greenhouse Gases or GHGs**

This Statement of Basis, Specific Statutory Authority and Purpose complies with the requirements of the Colorado Administrative Procedure Act Sections 24-4-103(4) and (12.5), C.R.S. for new and revised regulations.

Basis

Regulation Number 3 is designed to implement substantive regulatory programs authorized under the Colorado Air Pollution Prevention and Control Act ("Act") including provisions of the State Implementation Plan addressed in C.R.S. Section 25-7-105(1)(a), emission control regulations addressed in C.R.S. Section 25-7-105(1)(b), Prevention of Significant Deterioration requirements addressed in C.R.S. Section 25-7-105(1)(c), regulations as may be necessary and proper for the orderly and effective administration of construction permits and renewable operating permits addressed in C.R.S. Section 25-7-114.4(1), as well as other authorized programs under the Act. The current revisions have been promulgated in order to facilitate this goal. The revisions were proposed by the Air Pollution Control Division based on EPA's GHG Tailoring Rule. On June 3, 2010, EPA promulgated the "Prevention of Significant Deterioration and Title V Greenhouse Gas Tailoring Rule." See 75 Fed. Reg. 31514 (June 3, 2010). EPA's Greenhouse Gas (GHG) Tailoring Rule was designed to tailor the applicability criteria that determine which stationary sources and modification projects become subject to permitting requirements for GHGs under the Prevention of Significant Deterioration (PSD) and Title V Permitting Programs of the Clean Air Act (CAA).

Specific Statutory Authority

The Act, under C.R.S. Section 25-7-105(1)(a) authorizes the Air Quality Control Commission (Commission) to adopt rules necessary to implement the Act, and to adopt and revise comprehensive State Implementation Plans (SIP) to assure attainment and maintenance of national ambient air quality standards. C.R.S. Section 25-7-109 authorizes the Commission to adopt rules that are consistent with state policy regarding air pollution and with federal recommendations and requirements. C.R.S. Section 25-7-109(2) authorizes the Commission to regulate oxides of carbon, oxides of nitrogen and other chemicals, which encompasses the pollutant GHG. Additionally, Colorado is authorized to regulate GHGs under PSD and Title V in C.R.S. Sections 25-7-103(1.5), 25-7-114(3), 25-7-114.3, and 25-7-201. Additional authority for these revisions is set forth in C.R.S. Sections 25-7-106 and 25-7-109, and 25-7-114.

In order to maintain consistency between state regulations and federally enforceable regulations contained in Colorado SIP, the Commission intends these revisions be adopted into the SIP.

Purpose

The Commission has adopted revisions throughout Regulation Number 3 to address GHG regulation in Colorado. These revisions were made to incorporate EPA's GHG Tailoring Rule into Colorado's Title V and PSD Permitting Programs, and to extend synthetic minor permitting to Colorado's stationary sources seeking federally enforceable limits to avoid major source or major stationary source applicability thresholds specific to GHGs.

EPA's GHG Tailoring Rule establishes a phased approach for applying the CAA's PSD and Title V Permitting Programs to the sum of six GHGs.[1] The GHG Tailoring Rule has several different components including permitting thresholds and timing, commitments to the next steps, implementation options, and information requests.

1 The GHG air pollutant consists of the aggregate sum of six GHG gases: carbon dioxide ($CO_2$), nitrous oxide ($N_2O$), methane ($CH_4$), hydrofluorocarbons (HFCs), perfluorocarbons (PFCs), and sulfur hexafluoride ($SF_6$). These species of each GHG class are treated in aggregate, based on the total carbon dioxide equivalent ($CO_2e$).

On April 2, 2007, the U.S. Supreme Court held that GHGs are included in the definition of "air pollutant" under CAA Section 302(g). Massachusetts v. EPA, 549 U.S. 497 (2007). As part of this decision, the Court mandated EPA to determine under CAA Section 202(a) whether GHG emissions from new motor vehicles endanger public health or welfare, or if too much scientific uncertainty remains to make such a determination. [2]

2 CAA Section 202(a) requires EPA to "prescribe (and from time to time revise) … standards applicable to the emission of any air pollutant from any class or classes of new motor vehicles … which … cause, or contribute to, air pollution which may reasonably be anticipated to endanger public health or welfare."

On December 7, 2009, EPA issued the Endangerment Finding and the Cause or Contribute Finding, both addressing GHGs under CAA Section 202(a). See 74 Fed. Reg. 66496 (Dec. 15, 2009). EPA's Endangerment Finding found that GHGs endanger the public health and welfare of current and future generations. The Cause or Contribute Finding found that the combination of the six well-mixed GHGs from new motor vehicles contributes to the GHG pollution which threatens public health and welfare. EPA's findings were a prerequisite to establishing GHG standards for light-duty vehicles, but they did not in themselves impose any requirements on GHG stationary sources.

On May 7, 2010, EPA published the Light-Duty Vehicle Rule (LDVR) jointly with the National Highway Traffic Safety Administration to reduce GHG emissions and improve fuel economy of new passenger cars, light-duty trucks, and medium-duty passenger vehicles. See 75 Fed. Reg. 25324 (May 7, 2010). The new GHG emissions standards under the LDVR first apply to model year 2012 vehicles and become increasingly more stringent through model year 2016.

EPA addressed the implications of GHGs as a newly regulated pollutant under the LDVR through the Johnson Memo ("EPA's Interpretation of Regulations that Determine Pollutants Covered by Federal Prevention of Significant Deterioration (PSD) Permit Program"). See 75 Fed. Reg. 17004 (March 29, 2010). EPA concluded that a previously unregulated pollutant is subject to regulation once it is subject to actual control of emissions under the CAA or EPA regulation, and that control requirement takes effect. Accordingly, EPA concluded that once the LDVR takes effect on January 2, 2011 (the earliest date that a model year 2012 vehicle could be put on the market), GHGs will become regulated pollutants under the PSD and Title V permitting programs. Absent the Tailoring Rule, GHGs would then be subject to regulation at the existing PSD and Title V thresholds of 100 / 250 tons per year (tpy).

The foregoing federal actions now require appropriate changes to Colorado's regulations. Colorado law already provides the Commission authority and an obligation to regulate GHGs under the state's PSD and Title V permitting programs. Colorado's definition of "air pollutant" mirrors EPA's definition under the CAA. See C.R.S. Section 25-7-103(1.5) and CAA Section 302(g).[3] Following the U.S. Supreme Court's holding in Massachusetts v. EPA, GHGs are included in the definition of air pollutant under CAA Section 302(g). Colorado's PSD program applies PSD permitting requirements to new major stationary sources and major modifications. C.R.S. Section 25-7-210. Similarly, Colorado defines a Title V "major source" as "any stationary source […] that directly emits, or has the potential to emit, one hundred tons per year or more of any air pollutant." C.R.S. Section 25-7-114(3)(b). Furthermore, a Title V permit is required for any major source. C.R.S. Section 25-7-114.3(1)(b). The Division's proposed changes to Regulation Number 3 align these key definitions to Colorado's statute (which in turn map to the CAA) and add a definition of "subject to regulation," as defined in the Tailoring Rule.

3. The CAA defines "air pollutant" as "… any air pollution agent or combination of such agents, including any physical, chemical, biological, radioactive […] substance or matter which is emitted into or otherwise enters the ambient air." CAA Section 302(g). Colorado's statute defines "air pollutant" as "… means any fume, smoke, particulate matter, vapor, or gas or any combination thereof which is emitted into or otherwise enters the atmosphere, including, but not limited to, any physical, chemical, biological, radioactive […] substance or matter …" C.R.S. Section 25-7-103(1.5).

The Commission's mandate includes promulgation of regulations to reduce air pollution, including the promulgation of a comprehensive state implementation plan which "shall meet all requirements of the federal act and shall be revised whenever necessary or appropriate." C.R.S. Section 25-7-105; see also C.R.S. Section 25-7-102 (legislative declaration). Furthermore, Colorado's statutes provide that "In the formulation of each emission control regulation, the commission shall take into consideration […] the state policy regarding air pollution, as set forth in section 25-7-102 [and] Federal recommendations and requirements." C.R.S. Section 25-7-109(1)(b).

In addition to Colorado's statutory authority, federal PSD and Title V provisions under the CAA also place requirements on states to maintain PSD and Title V Permitting Programs in compliance with federal requirements. The chain of events described above renders GHGs to be considered a regulated pollutant subject to the federal PSD and Title V permitting requirements. Under PSD, EPA mandates that "each applicable implementation plan shall contain emission limitations and such other measures as may be necessary, as determined under regulations promulgated under this part, to prevent significant deterioration of air quality …" CAA Section 161. Under Title V, the CAA provides that "Whenever the Administrator makes a determination that a permitting authority is not adequately administering and enforcing a program, or portion thereof, in accordance with the requirements of this title, the Administrator shall provide notice to the State and may, prior to the expiration of the 18-month period referred to in paragraph (2), in the Administrator's discretion, apply any of the sanctions specified in section 179(b)." CAA Section 502(i)(1).

In order to avoid both the possibility of sanctions for failure to comply with EPA's permitting programs, as well as the unsustainable workload of regulating GHGs at the existing permitting thresholds of 100 / 250 tpy, the Division proposes regulatory revisions to comport with EPA's GHG Tailoring Rule.

Permitting Thresholds and Timing

Regarding permitting thresholds and timing, EPA's GHG Tailoring Rule identifies three steps – Steps 1, 2 and 3 – to phase in GHG permitting requirements over time. This rulemaking addresses **only** Steps 1 and 2, as discussed in EPA's GHG Tailoring Rule. While EPA's GHG Tailoring Rule generally discusses a Step 3,[4] it provides few details on any associated timing and thresholds; instead EPA's GHG Tailoring Rule establishes an enforceable commitment to complete another rulemaking no later than by July 1, 2012 for Step 3 and beyond. The Commission intends to expressly address these future actions expeditiously as they arise.

4 EPA proposes to promulgate a separate rule specific to Step 3 by July 1, 2012. It is anticipated that this Step 3 will span from July 1, 2013 through April 30, 2016. EPA offers limited regulatory details, but states that no stationary sources having potential to emit GHG emissions of less than 50,000 tons per year CO2e would trigger PSD or Title V Permitting Programs under the Tailoring Rule due to GHG emissions alone. No other details are provided.

This rulemaking establishes key definitions and the authority to regulate GHGs as well as addresses Steps 1 and 2 as identified in EPA's GHG Tailoring Rule. Step 1 spans from January 2, 2011 through June 30, 2011, and applies PSD and Title V permitting requirements to GHG emissions at "anyway sources," or stationary sources that are already subject to these permitting requirements for non-GHG pollutants. During Step 1, no source shall be required to obtain a Title V operating permit or PSD permit solely due to GHG emissions. Step 2 spans from July 1, 2011 through June 30, 2013. In Step 2, in addition to the requirements of Step 1, PSD and Title V permitting requirements apply to stationary sources which may be major[5] for GHG emissions and no other regulated pollutant.

5 Major source or major stationary source.

EPA's GHG Tailoring Rule sets a 100,000 tpy carbon dioxide equivalent (CO2e) applicability threshold for stationary sources that are major for GHG and no other non-GHG NSR regulated pollutant for PSD, and re-affirms that a significant emissions increase and a significant net emissions increase must occur in order to trigger PSD review. PSD and Title V permitting applicability thresholds and significance levels have traditionally been determined on a mass-basis. However, the Tailoring Rule sets a PSD significance level for GHG at 75,000 tpy on a CO2e basis. There are distinct units of measure used in identifying GHG applicability thresholds and significance levels. Some are mass-based and some are CO2e-based. The distinction between the two focuses on whether or not the global warming potential (GWP) is applied to each individual GHG species before summing the total of GHG classes for comparison to the appropriate value.

The Commission recognizes that the EPA is currently developing GHG permitting guidance. At its earliest convenience prior to January 2, 2011, the Division is instructed to provide permitting guidance to sources to minimize uncertainty.

Permitting and Application Requirements

The Commission recognizes the difficulties in developing a GHG inventory in short order, and directs the Division to request permit applicants which are required to provide a GHG inventory to submit one by a reasonable deadline set by the Division.

See the citations below for further information.

*Complete Application*

In Regulation Number 3, Part C, Section III.C.3.a., the Commission requires that all information related to the "emissions of pollutants sufficient to verify which requirements are applicable to the source" (which includes GHG) must be included in a complete application. Similarly, 40 C.F.R. 70.5(c)(3)(i) requires that Title V applications must include emissions of all regulated air pollutants.

Further, in Regulation Number 3, Part C, Section IV.B.4, the Commission requires that a source update its permit application to address any requirements that become applicable after the date the source has submitted its application, prior to issuance of the draft permit for public comment.

*Application Shield*

In Regulation Number 3, Part C, Section II.B., the Commission grants a defense to an enforcement action to sources which submit a timely and complete application under Part C until a final determination on the permit has been made. Per Regulation Number 3, Part C, Section IV.D., after an application is deemed complete, the Division may request additional information in writing and set a reasonable deadline for response. However, the application shield defense is not available if the source "fails to submit by the deadline specified in writing by the Division any additional information identified as necessary to process the application, or to otherwise supplement its application in accordance with the provisions of Regulation Number 3, Part C, Sections IV.B.3. and IV.B.4."

*Applicable Requirement*

In Regulation Number 3, Part A, Section I.B.9., the Commission defines applicable requirement consistently with that definition found in 40 C.F.R. Part 70, Section 70.2. Based on these definitions the mandatory GHG Reporting Rule requirements codified in 40 C.F.R. Part 98 do not meet the definitions of applicable requirements at this time; however, any GHG BACT requirement or other federally enforceable GHG requirements, including GHG synthetic minor permit conditions necessary to avoid major source or major stationary source thresholds are considered applicable requirements.

Regulation Number 3, Part C, Section V.B.4. requires that any operating permit address "all applicable requirements," however existing Title V sources that do not undergo PSD review should not trigger any GHG applicable requirements.

"Subject to Regulation or Requirement"

Prior to this rulemaking the Title V operating permit requirements of Regulation Number 3, Part C, Sections II.A.1.g., II.E.1. and II.E.2. already contained the language "subject to regulation or requirement", followed by a specific reference to the Federal Act or another part of Regulation Number 3. The phrase "subject to regulation" was addressed in the Johnson Memo, "EPA's Interpretation of Regulations that Determine Pollutants Covered by the Federal Prevention of Significant Deterioration (PSD) Permit Program" and later codified in the GHG Tailoring Rule and Regulation Number 3, Part A, Section I.B.44. See 75 Fed. Reg. 17004 (March 29, 2010). For the purpose of these sections, the definition of "subject to regulation" is not applicable and the full phrase "subject to regulation or requirement" relates to the reference at the end of those statements.

Rescission Clause

The Commission recognizes the uncertainty facing GHG stationary sources, given the potential for future federal legislation and the extensive pending legal challenges to GHG regulation under the CAA. The Commission intends GHG regulation in Colorado be consistent with the Federal Act, and has inserted a rescission clause making the effectiveness of the term Subject To Regulation dependent upon federal enforceability. Should either federal legislation or Court rulings from the District of Columbia Circuit Court of Appeals or the U.S. Supreme Court limit or render ineffective the regulation of GHG emissions under the PSD or Title V provisions of the Federal Act, then GHGs shall only be subject to regulation under this Regulation Number 3 for the affected permitting program(s) to the same extent. Example 1: if the regulation of GHGs under both PSD and Title V is vacated in whole, then all GHG emissions limitations or requirements included in any construction or operating permit issued under this Regulation Number 3 shall no longer be enforceable. Example 2: if the Court remands the regulation of GHG emissions to EPA such that GHG regulation under the Federal Act is temporarily ineffective, either in whole or in part, any GHG emissions limitation or requirement included in any permit issued under this Regulation Number 3 shall be limited or rendered ineffective to the same extent. Sources may actively seek to maintain those permit conditions if they so choose pursuant to Regulation Number 3, Part A, Section I.A. These examples are not intended to address all potential outcomes, but rather to provide some degree of implementation guidance. The Commission intends that this rescission will be automatically and immediately effective final of applicable court action or legislation. When triggered, this clause prevents regulation of GHG under Regulation Number 3 to the same extent of the federal action or court ruling and may require a new rulemaking action by the Commission to regulate GHGs for the affected permitting program, including any new details of such future regulation.

Synthetic Minor Permits for GHGs

No minor source air pollution construction permits are required at this time for GHGs, except where stationary sources voluntarily seek federally enforceable limits for GHGs to avoid major source PSD and Title V permitting requirements. (Regulation Number 3, Part B, Section II.A.7.) An application for a voluntary synthetic minor construction permit must include GHG emissions reported on Division-approved forms. Construction permits shall be issued based on production/process rates requested in the application, and the emission limit requested shall be a permit condition. (Regulation Number 3, Part B, Section II.A.4.)

If the above-mentioned rescission clause is triggered, any federally enforceable GHG emission limits contained in synthetic minor permits are no longer enforceable. The stationary source is requested to submit a cancellation request to the Division to cancel GHG emissions points and permits.

**Regulation Number 3 Revisions:**

The revisions to Regulation Number 3 as approved by the Commission are summarized below.

**Part A**

- Add Regulation Outline
- Add new definitions of Greenhouse Gas and Carbon Dioxide Equivalent. The CO2e definition incorporates by reference EPA's GWP codified via the GHG Mandatory Reporting Rule (Sections I.B.10., I.B.23.)
- Revise Major Source definition so that it applied to regulated NSR pollutant (which includes GHG) as well as to air pollutants (which does not included GHG) so that GHG is addressed and the definition may be used to establish the mass based GHG threshold (Section I.B.25.b.)

- Add new definition of Subject to Regulation consistent with EPA's GHG Tailoring Rule and include the rescission clause as discussed above (Section I.B.44.)

- Revise annual emission fees to exclude GHGs (Section VI.D.)

**Part B**

- Revise general permitting requirements to authorize the Division to issue synthetic minor permits for GHGs where stationary sources voluntarily choose to seek federally enforceable limits for GHG if they would otherwise be subject to PSD or Title V Permitting Programs (Sections II.A.4., II.A.7.)

**Part C**

- Clarify that complete Title V Operating Permit applications include the reporting of GHG emissions as they are pollutants which may be subject to requirements applicable to the source, but not air pollutants, under Regulation 3 definitions (Section III.C.3.a.).

**Part D**

- Revise the Definitions (Section II.A.):

- Revise BACT, Major Modification and Major Stationary Source Definition to use the term Regulated NSR Pollutant for consistency and remove italics consistent with EPA's GHG Tailoring Rule so that these definitions become effective by January 2, 2011 (Sections II.A.8., II.A.22., II.A.24.a., II.A.24.a.(ii) and II.A.24.b.)

- Revise Regulated NSR Pollutant definition and remove italics consistent with EPA's GHG Tailoring Rule so that it becomes effective by January 2, 2011 (Section II.A.38.)

Additionally, the Commission approves typographical, grammatical and formatting changes, as necessary.

**I.UU. Adopted January 7, 2011**

Regulation Number 3, Part D (Concerning Major Stationary Source New Source Review and Prevention of Significant Deterioration) and Part F (Best Available Retrofit Technology (BART) and Reasonable Progress for Regional Haze)

This Statement of Basis, Specific Statutory Authority and Purpose complies with the requirements of the Colorado Administrative Procedures Act, Section 24-4-103, C.R.S, and the Colorado Air Pollution Prevention and Control Act, Sections 25-7-110 and 25-7-110.5, C.R.S (the Act).

**Specific Statutory Authority**

The Colorado Air Quality Control Commission (Commission) promulgates this regulation pursuant to the authority granted under Colorado Revised Statutes, Sections 25-7-105(1)(c), (authority to adopt a prevention of significant deterioration program); 25-7-109(1)(a) (authority to require the use of air pollution controls); 25-7-109(2)(a) (authority to adopt emission control regulations pertaining to visible pollutants); 25-7-114.4(1) (authority to adopt rules for the administration of permits); and 40-3.2-208 (authority to incorporate emission reduction plans for rate-regulated utilities within the state's Regional Haze State Implementation Plan).

**Basis and Purpose**

PART D

These revisions to Regulation Number 3, Part D change the review and revision period for the Regional Haze Long Term Strategy (LTS) from every three years to every five years. This change aligns the reporting periods for the Regional Haze LTS and the Regional Haze progress reports that are required every five years pursuant to 40 C.F.R. Section 51.308(g).

PART F

On July 1, 1999, the U.S. Environmental Protection Agency (EPA) promulgated the final Regional Haze Rule (Rule), which went into effect, on August 30, 1999, and which requires each state to submit a State Implementation Plan (SIP) to address regional haze. The Rule is intended to achieve the national visibility goals as expressed in Section 169(a) of the Clean Air Act, 42 U.S.C. Section 7491. Colorado must develop a SIP revision in coordination and consultation with other states, tribes, federal land managers, EPA and Regional Planning Organizations (RPOs) designated by EPA. In the west, the RPO is the Western Regional Air Partnership (WRAP).

Regional Haze is a visibility impairment that is caused by multiple sources over a broad geographic region. EPA's Regional Haze Rule requires every state to submit a SIP designed to improve visibility in its mandatory Class I federal areas (Class I areas). Class I areas are areas of great scenic importance, such as national parks and wilderness areas. There are 12 Class I areas in Colorado, and 156 nationwide.

A key element of EPA's regional haze program is Best Available Retrofit Technology (BART) for certain emission sources. Section 169A(b)(2)(A) of the Clean Air Act requires BART for certain existing major facilities, placed into operation between August 7, 1962 and August 7, 1977, that have the potential to emit more than 250 tons of visibility-reducing pollution a year. EPA's Regional Haze Rule requires SIPs to include BART emission limits for each subject-to-BART source that may reasonably be anticipated to impair visibility in any Class I area, unless the state demonstrates that an emissions trading program or other alternative measures will achieve greater reasonable progress toward natural visibility conditions. See 40 CFR Part 51 Section 308(e). EPA promulgated a BART Rule separate from its Regional Haze Rule. EPA's BART Rule includes guidelines (Appendix Y) regarding how states should make BART determinations. See 70 Fed. Reg. 39104 (July 6, 2005). EPA also promulgated a "BART Alternative" Rule. See 71 Fed. Reg. 60612 (October 13, 2006). The BART Alternative Rule allows an alternative program to source-by-source BART, if the program results in greater reasonable progress than would occur pursuant to individual BART.

States were required to submit their regional haze SIPs to EPA by December 17, 2007. The Regional Haze Rule establishes the year 2064 as the date by which a goal of visibility at natural background levels is desired in all Class I areas. The Rule divides the 2007-2064 time periods into numerous planning periods. States were required to submit their initial RH SIP by December 31, 2007, then a revised Regional Haze SIP to EPA by July 31, 2018, and every ten years thereafter. See 40 CFR Section 51.308(f).

Colorado submitted much of its regional haze SIP (including most of its BART determinations) to EPA in early 2008 for review. Following additional revisions, the Commission approved the remainder of Colorado's BART determinations in December 2008, and submitted Colorado's Regional Haze SIP to EPA's Region 8 for review in 2009.

Upon review, EPA Region 8 informed Colorado that its regional haze SIP submittal was not approvable and needed to be revised before EPA could reconsider it for inclusion in the State Implementation Plan. EPA has identified deficiencies with Colorado's Regional Haze Element of the SIP, including the basis for and enforceability of BART determinations and the lack of reasonable progress goals (RPGs) and RP source determinations. These alleged deficiencies must be addressed in order for EPA to approve the Regional Haze element of the SIP. This regulation is the second part of a bifurcated rulemaking process in which the Commission adopted the remaining outstanding Regional Haze SIP elements.

EPA made a finding on January 15, 2009 that 37 states, including Colorado, had failed to make all or part of the required Regional Haze SIP submissions. See 74 Fed. Reg. 2393 (January 15, 2009). This action started a clock by which states must have approved SIPs, or EPA must promulgate Federal Implementation Plans (FIPs) within two years (*i.e.*, by January 15, 2011). EPA initiated actions in Colorado to begin preparing a FIP, and this action by the Commission is taken to complete the adoption of a regional haze element of the SIP, address the deficiencies that Region 8 EPA has identified, and to prevent such a federal action in Colorado, with its attendant consequences (*e.g.*, federal determinations of BART, federal reasonable progress determinations, federal permits, and state loss of CAA grant monies so EPA can prepare a FIP).

During the 2010 legislative session, the Colorado legislature passed House Bill 10-1365, the "Clean Air - Clean Jobs Act" (CACJA). The CACJA sets forth requirements applicable to investor owned utilities in Colorado (Public Service Company of Colorado (PSCo) and Black Hills Energy) and certain of their electric generating units. The CACJA requires the investor owned utilities to submit emission reduction plans to the Colorado Public Utilities Commission (PUC), and provides that the Commission shall consider the air quality provisions of the emission reduction plans for incorporation into the regional haze element of Colorado's SIP. See Section 40-3.2-208, C.R.S. PSCo and Black Hills submitted their emission reduction plans to the PUC on August 13, 2010, and the PUC approved the plans on December 15, 2010.

The Commission adopted into Regulation Number 3 BART determinations for PSCo's Hayden and Comanche plants, two units at CENC's Golden plant, CEMEX's Lyons Portland cement plant, and Colorado Springs Utilities' Drake power plant. The Commission also adopted an Alternative to BART program for two units at Tri-State Generation and Transmission Association's Craig power plant. The Commission determined that, for nitrogen oxide (NOx) emissions, the appropriate BART control for Craig Units 1 and 2 would be emission rates associated with the assumed installation and operation of selective non-catalytic reduction (SNCR). As an alternative to BART, it was proposed and the Commission adopted, a more stringent NOx emissions control plan that consists of emission limits associated with the assumed operation of SNCR for Unit 1 and the assumed operation of SCR for Unit 2. The state has determined that the alternative program achieves greater reasonable progress than would be achieved through the installation and operation of source-by-source BART, and thus meets the requirements of the regional haze rule.

The Commission also adopted into Regulation Number 3 a BART Alternative for a number of PSCo plants and incorporated it into the Regional Haze SIP. The BART Alternative is based on reductions achieved as a result of a combination of shutdowns and retrofit emissions controls at certain PSCo facilities planned as part of HB 10-1365. The BART Alternative includes ten units at four PSCo facilities. The facilities included in the BART Alternative include Arapahoe Units 3 and 4, Cherokee Units 1-4, Valmont and Pawnee. The BART Alternative includes both BART and non-BART sources. The non-BART sources are older than the BART timeframe, and in effect will all be controlled by 2017 and reduce their NOx and SO2 emissions as a result of enforceable facility retirement dates and, for one unit, fuel switching to natural gas as a peaking unit. For the BART sources, Cherokee 4, Pawnee and Valmont, Valmont will be retired by 2018, Pawnee will be fully controlled by mid-2015, and Cherokee will operate on natural gas by 2018. The state has determined that the BART Alternative achieves greater reasonable progress than would be achieved through the installation and operation of source-by-source BART and RP determinations at the covered sources, and thus meets the requirements of the Regional Haze rule. PSCo has designed and proposed the BART Alternative to meet the state CACJA. The Commission determined that to the extent there is any inconsistency between the CACJA and older, more generic legal requirements, the more recent and specific CACJA controls. The state has used simplifying assumptions to compare the emission reductions and visibility impacts associated with the PSCo BART Alternative, and believes that the BART Alternative is clearly superior to, and will result in greater reasonable progress than, source-by-source BART. For example, the state has determined and demonstrated that PSCo's BART Alternative emissions reductions are greater than, and would provide greater reasonable progress than, the presumptive or source-by-source BART limits. The Commission also adopted retirement dates of "no later than" July 1, 2012 and December 31, 2016 for Cherokee Units 1 and 3, respectively. In doing so, the Commission is no way rejecting any portion of PSCo's emission reduction plan as approved by the PUC on December 15, 2010 (Decision No. C10-1328). Rather, the Commission's action is intended to provide flexibility and consistency in light of PSCo's pending application for rehearing, reargument or reconsideration (RRR) before the PUC, in which PSCo states that the revised dates are important for providing sequencing of activities that will ensure electrical system reliability in the Denver Metropolitan area. These dates are also wholly consistent with the PUC's decision because PSCo can comply with the dates established by both the PUC and the Commission, regardless of how the PUC rules on PSCo's RRR application. The Commission also notes that Hayden, another PSCo BART source, is not part of the BART Alternative program. The PUC approved controls for Hayden as part of PSCo's emission reduction plan under HB 10-1365, consistent with the state's BART determination for that source.

The Commission also established non-binding goals for each Class I area in Colorado (expressed in deciviews) that provide for Reasonable Progress (RP) towards achieving natural visibility conditions in 2018 and to 2064. See 40 C.F.R. Section 51.308(d)(1). The reasonable progress goals (RPGs) provide for improvement in visibility for the most-impaired (20% worst) days over the period of the SIP and ensure no degradation in visibility for the least-impaired (20% best) days over the same period. The Commission adopted into Regulation Number 3 emission limits for "reasonable progress" sources that have a significant impact on visibility impairment in Class I areas, in order to help the state make reasonable progress towards improving visibility in this first planning period. These sources include Black Hills Energy Clark Station (a HB10-1365 facility), the Holcim Cement Plant, Tri-State Generation and Transmission Association's Craig Station Unit 3 and Nucla Station, Platte River Power Authority's Rawhide Station, Colorado Springs Utilities' Nixon Power Plant, PSCo's Cameo plant, and CENC's Unit 3.

For all BART and BART Alternative determinations made by the Commission in the November 2010 – January 2011 proceedings, a source that has installed BART or implemented a state-approved BART Alternative is exempted from the imposition of further regional haze controls during this first regional haze planning period (i.e., through December 31, 2017). This exemption applies only to regional haze, and does not apply to controls or emission reductions that may be required or otherwise imposed pursuant to other air pollution programs (including, but not limited to, ozone standards).

The revisions to Regulation Number 3, Part F also apply Monitoring, Recordkeeping and Recording (MRR) Provisions to BART, BART Alternative and Reasonable Progress emission limits.

In addition to the regulatory changes described above, the Commission adopted changes to Colorado's Regional Haze SIP. Many of the changes are non-substantive edits while other changes address comments from Federal Land Managers, incorporate the justification for the BART and reasonable progress determinations, and provide the justification for the reasonable progress goals. The following presents an overview of the content of Colorado's Regional Haze SIP document:

Chapter 1 – Overview

Chapter 2 – Plan Development and Consultation

Chapter 3 – Monitoring Strategy

Chapter 4 – Baseline and Natural Visibility Conditions in Colorado, and Uniform Progress for Each Class I area

Chapter 5 – Sources of Impairment in Colorado

Chapter 6 - Best Available Retrofit Technology

Chapter 7 – Visibility Modeling and Apportionment

Chapter 8 – Reasonable Progress

Chapter 9 – Long Term Strategy

Chapter 10 – Commitment to Consultation, Progress Reports, Periodic Evaluations of Plan Adequacy, and Future SIP Revisions

Chapter 11 – Resource and Reference Documents

Appendix A – Periodic Review of Colorado RAVI Long Term Strategy

Appendix B – SIP Revision for RAVI Long Term Strategy

Appendix C – Technical Support for the BART Determinations

Appendix D – Technical Support for the Reasonable Progress Determinations

The revised chapters are intended to fully replace previously adopted SIP chapters.

Additional Considerations

The Commission provides the following additional statement, consistent with Sections 25-7-110.5(5)(a) and 110.8, C.R.S.

(I) Colorado's proposed Regional Haze regulations and SIP revisions are consistent with EPA's federal requirements under the Regional Haze rule. There is no binding requirement on how a State may "consider" the federal statutory and regulatory factors in determining BART and RP and establishing RPGs. The manner and method of consideration is left to the state's discretion. States are free to determine the weight and significance to be assigned to each factor. See 70 Fed. Reg. 39104, 39170 (July 6, 2005). State discretion is a cornerstone of the regional haze rule.See id., at 39137 ("Congress evinced a special concern with insuring that States would be the decision makers."). States also have flexibility to consider any other factors that the state determines to be relevant. See U.S. EPA, "Guidance for Setting Reasonable Progress Goals Under the Regional Haze Program," p. 5-1 (June 2007). Federal law also allows states flexibility to adopt alternative programs that provide greater reasonable progress than BART. The Commission has adopted such alternatives for PSCo and Tri-State sources. The Commission finds that the revisions adopted in this hearing are wholly consistent with the discretion and expertise to be applied by state agencies under the federal act. Accordingly, the proposed revisions are no more stringent or different than federal law, and Sections 25-7-110.5 and 110.8 do not appear to apply.

Additionally, HB10-1365 provides, in part, that the Commission must vacate this rulemaking proceeding and must initiate a new proceeding for the consideration of alternative proposals for the appropriate controls for those units covered by the utility plans for inclusion in the regional haze element of the state implementation plan if, among other things, the Commission rejects any portion of the plans as approved by the PUC. Section 40-3.2-208(2)(b), C.R.S. If the Commission were to reject any portion of the utility plans, this proceeding would be vacated and a new proceeding initiated, making it impossible for Colorado to submit a timely and complete SIP revision to address Regional Haze, and resulting in a FIP. Under these circumstances, it is reasonable to conclude that the Commission rules regarding "1365" sources are being adopted to implement prescriptive state requirements, that the Commission has no significant policy-making options with respect to these sources, and that many provisions of Sections 25-7-110.5 and 110.8 do not apply. See Section 25-7-110.5(2), C.R.S.

Despite the foregoing, certain elements of this proceeding could be viewed (as certain parties have alleged) as exceeding the federal act or differing from the federal act. For example, the closure or repowering of PSCo facilities would not be required solely by EPA's Regional Haze Rule. Accordingly, the Commission is providing this additional statement, consistent with Sections 25-7-110.5(5)(a) and 110.8, C.R.S.

(II) EPA's regional haze requirements are performance based, and the regional haze rule sets forth factors that states must consider when assessing controls and emission limits for sources emitting visibility impairing pollutants. Section 169A of the federal Clean Air Act (1977) sets forth the following national visibility goal: "Congress hereby declares as a national goal the prevention of any future, and the remedying of any existing, impairment of visibility in mandatory Class I Federal areas which impairment results from man-made air pollution." 42 U.S.C. Section 7491. To help facilitate this goal, EPA finalized the regional haze rule in 1999. The Rule requires States to adopt SIPs to address visibility impairment in the Class I areas. Critical components of such SIPs (particularly the SIP for the first planning period) are BART and RP. EPA provides flexibility to states regarding how to apply the relevant factors to BART and RP analyses.

(III) Applicable federal requirements specifically address the issues regarding visibility impairment in Class I areas that are of concern to Colorado. Applicable federal requirements do not specifically address all of the issues that are of concern to Colorado. House Bill 10-1365 is intended to address Colorado's compliance with a number of federal Clean Air Act requirements in a comprehensive and more efficient fashion than in a step-by-step (or regulation by regulation) approach. The legislation specifically declares that it is intended to create "a coordinated plan of emissions reductions…to meet the requirements of the federal act…at a lower cost than a piecemeal approach." Section 40-3.2-202(1), C.R.S. While regional haze is an important consideration in the context of HB10-1365, it is not the only one. HB10-1365 aims to address other air pollution issues as well, including national standards for ozone. See, e.g., Sections 40-3.2-204(1), 204(2)(b)(II)(B) and 205(1)(c), C.R.S. Data regarding visibility impairing emissions and control technologies was considered in the federal process leading up to the promulgation of the Regional Haze Rule. See, e.g., EPA's "Technical Support Document for BART SO2 Limits for Electric Generating Units," April 1, 2005, and "Technical Support Document for BART NOx Limits for Electric Generating Units and Technical Support Document for BART NOx Limits for Electric Generating Units Excel Spreadsheet," April 15, 2005, Memoranda to Docket Number 2002-0076. These Memoranda reflect an analysis of all individual BART-eligible units in the country, including Colorado.See 70 Fed. Reg. at 39131-35. See also EPA's "Regulatory Impact Analysis for the Final Clean Air Visibility Rule or the Guidelines for Best Available Retrofit Technology (BART) Determinations Under the Regional Haze Regulations," U.S. EPA, June 2005. Additionally, the state determines that the regulatory requirements do not exceed the requirements of the federal act because the state is not imposing the BART alternative measures on an unwilling entity. Rather, the sources voluntarily proposed the packages as BART alternative measures and, in the case of PSCo, in order to comply with HB10-1365.

(IV) The adopted rule will provide certainty to sources, by providing necessary monitoring, recordkeeping and reporting mechanisms and clear timing requirements to ensure the achievability of the specified closure or performance based standards. With respect to the "1365" sources in particular, the requirements improve the utilities' ability to comply in a cost-effective manner while preventing or reducing the need for costly retrofits to meet more stringent requirements later.

(V) If the state does not take action by January 2011, EPA has indicated it will promulgate a FIP. The state and federal rules also have similar time frames for implementation. BART controls must be installed as soon as practicable but in no event later than five years after EPA approval of the regional haze SIP, and all BART, BART alternatives and RP controls must be implemented within this first planning period (i.e., before January 1, 2018).

(VI) The adopted rule will assist in establishing and maintaining a reasonable margin for accommodation of uncertainty and future growth.

(VII) The adopted rule establishes reasonable equity for sources subject to the rule by providing the same standards for similarly situated sources. BART and RP determinations are very source specific; different controls and emission limits are to be expected and reflect the State's source-specific consideration of federal statutory and legal factors, and of the state's implementation of HB10-1365.

(VIII) If the state rule were not adopted, EPA has indicated it will promulgate a FIP. This would likely result in more costly control requirements for sources which would be passed on to consumers.

(IX) The Regional Haze Rule requires associated State procedural, reporting and monitoring and recordkeeping requirements. The procedural, reporting, monitoring and recordkeeping requirements provided in Colorado's rule do not differ from, and often incorporate by reference, federal requirements.

(X) Demonstrated technology is available to control and monitor visibility impairing emissions.

(XI) The adopted rule will contribute to the prevention of pollution by reducing visibility impairing emissions.

(XII) A no action alternative would not address the required standard, and could result in EPA's promulgation of a FIP.

(XIII) All regulatory changes in this proceeding are based on reasonably available, validated, reviewed, and sound scientific methodologies. All information made available by interested parties has been reviewed and considered by the Commission.

(XIV) Evidence in the record supports the finding that the rule shall result in a demonstrable reduction of pollutants that contribute to regional haze.

(XV) Evidence in the record supports the finding that the rule shall bring about reductions in risks to human health or environment, and provide other benefits (e.g., protection of visibility) that justify the cost to government, the regulated community, and to the public to implement and comply with the rule.

(XVI) The Commission has chosen the alternative that is the most cost effective, provides the regulated community flexibility, and which achieves the necessary reductions in air pollution. The alternative will maximize the air quality benefits of regulation in the most cost effective manner. The Commission notes that no parties provided alternate proposals to the PSCo BART Alternative during this proceeding. The Commission also notes that in approving PSCo's emission reduction plan, the Colorado Public Utilities Commission thoroughly considered the economic impacts and concluded that that the approved plan comes at a lower cost to ratepayers than an all-controls option. Even if for some reason PSCo's BART Alternative were not determined to be the most cost effective option, the Commission finds that approval of the BART Alternative and incorporation of the alternative into the Regional Haze SIP is consistent with the legislature's intent in adopting the CACJA.

**I.VV. Adopted October 20, 2011**

Regulation Number 3, Part A, B, C and D – addressing federal changes to the New Source Review (NSR) Program related to PM2.5 National Ambient Air Quality Standards (NAAQS), several recent Environmental Protection Agency (EPA) State Implementation Plan (SIP) actions in which EPA partially disapproved various SIP revisions, EPA's Deferral of Biogenic Sources of CO2 Emissions, other miscellaneous revisions, and typographical, grammatical and formatting errors.

This Statement of Basis, Specific Statutory Authority and Purpose complies with the requirements of the Colorado Administrative Procedures Act, Section 24-4-103, C.R.S, and the Colorado Air Pollution Prevention and Control Act, Sections 25-7-110 and 25-7-110.5, C.R.S (the Act).

**Specific Statutory Authority**

The Colorado Air Quality Control Commission (AQCC) promulgates this regulation pursuant to the authority granted under Colorado Revised Statutes, Sections 25-7-105(1)(c), (authority to adopt a prevention of significant deterioration program); 25-7-109(1)(a) (authority to require the use of air pollution controls); 25-7-109(2)(a) (authority to adopt emission control regulations pertaining to visible pollutants); and 25-7-114.4(1) (authority to adopt rules for the administration of permits).

**Basis and Purpose**

EPA promulgated federal changes to the New Source Review (NSR) Program, which must be incorporated into Regulation Number 3 in order to maintain consistency with the federal NSR Program related to PM2.5 National Ambient Air Quality Standards (NAAQS). Subsequently, EPA disapproved and proposed to disapprove Air Pollutant Emission Notice (APEN) exemption provisions in Regulation Number 3, associated with Colorado's September 1997, April 2003 June 2003, July 2005, August 2006, and August 2007 SIP submittals. Also, EPA proposed its Deferral of Biogenic Sources of CO2 Emissions, deferring biogenic carbon dioxide (CO2) from regulation under the federal Prevention of Significant Deterioration (PSD) and Title V Permitting Programs for three years. In addressing the above actions, several additional Regulation Number 3 provisions were identified in need of revision.

Sources affected by this proposal include PM2.5 and CO2 emission sources, as well as open burning sources, mobile sources, stationary internal combustion engines, emergency generators, oil and gas surface water impoundments, deaerator/vacuum pump exhaust, and air curtain destructors.

PM2.5 Related Rules

On February 21, 2008, the AQCC adopted revisions to Regulation Number 3, Parts A and B to identify PM2.5 as a criteria pollutant, triggering reporting and minor source permitting requirements. However, the AQCC did not make corresponding revisions to major stationary source permitting requirements under the New Source Review (NSR) Program as the EPA had not yet promulgated the associated PM2.5 implementation rules. Since that time, EPA promulgated a series of rules regarding the regulation of PM2.5 under the NSR program. See "Implementation of the New Source Review (NSR) Program for Particulate Matter Less than 2.5 Micrometers (PM2.5)" (*73 FR 28321,* May 16, 2008), "Prevention of Significant Deterioration (PSD) for Particulate Matter Less Than 2.5 Micrometers (PM2.5) – Increments, Significant Impact Levels (SILs) and Significant Monitoring Concentration (SMC)" (*75 FR 64864,* October 20, 2010), "Requirements for Preparation, Adoption, and Submittal of Implementation Plans" (76 FR 18870, April 6, 2011), and "Implementation of the New Source Review (NSR) Program for Particulate Matter Less Than 2.5 Micrometers (PM2.5); Final Rule to Repeal Grandfather Provision" (*76 FR 28646,* May 18, 2011). The 2008 and 2010 rules, combined with the December 21, 2010 promulgation of the methodology to test for PM2.5, provide a complete framework establishing how to apply PM2.5 to the NSR Program. Prior to the promulgation of the December 2010 rules, application of PM2.5 to the NSR Program made little sense. See *75 FR 80118.* Consequently, the AQCC chose to wait to adopt the suite of PM2.5 implementation rules until after the last of the PM2.5 implementation rules and the 2010 PM2.5 testing methodology were finalized.

The May 16, 2008 rule provided flexibility in designating PM2.5 precursor pollutants. While sulfur oxides (SO2) must be treated as a PM2.5 precursor in all areas of the state, more flexibility is afforded to nitrogen oxides (NOx), volatile organic compounds (VOCs) and ammonia (NH3). This rule requires that NOx be presumed a PM2.5 precursor state-wide unless a state demonstrates that NOx is not a "significant contributor" to PM2.5 concentrations within any area. See*73 FR 28328.*However, VOCs and NH3 are not required to be treated as PM2.5 precursors, except that high molecular weight VOCs (equal to or greater than 25 carbon atoms and low vapor pressure) will be addressed as a condensable particulate. See *73 FR* 28329-283330.

At this time, the AQCC has identified SO2 and NOx as PM2.5 precursors, state-wide. Based on the limited PM2.5 modeling and monitoring data available for Colorado, the AQCC determined that there is insufficient evidence to claim either way that NOx emissions do or do not contribute significantly to the concentration of PM2.5 in any area in Colorado. Without evidence to narrow the identification of NOx as a precursor to specific areas, Colorado must identify NOx as a PM2.5 precursor state-wide. Less is known about VOCs and NH3 and their contribution to PM2.5 in Colorado, and so Colorado has chosen to not identify them as PM2.5 precursors at this time.

EPA Partial Disapproval Actions

On October 3, 2011, EPA's action granting partial disapproval and partial approval of revised Air Pollution Emission Notice (APEN) and permitting exemptions that the Commission submitted to EPA as SIP revisions in September 1997, June 2003, July 2005, August 2006, and August 2007, was published in the Federal Register. See *76 FR 61054.* EPA partially disapproved APEN exemptions for open burning, mobile sources, stationary internal combustion engines, emergency generators, oil and gas surface water impoundments, deaerator/vacuum pump exhaust, and air curtain destructors. The basis for EPA's disapproval of the subject provisions and the revisions intended to address each provision are as follows:

Open burning APEN exemption was corrected to reference federally enforceable Regulation Number 1 (Part A, Section II.D.1.q.). EPA commented that the change in reference from Regulation Number 1, which is part of Colorado's SIP, to Regulation Number 9, which is not part of Colorado's SIP, was not approvable.

Mobile sources APEN exemption was clarified (Part A, Section II.D.1.ppp.) and associated revisions were made to the insignificant activities list (Part C, Section II.E.3.uuu.). EPA commented that these exemptions only apply to stationary sources, not non-road engines and not sources being used for transportation purposes.

Stationary internal combustion engine APEN exemption was repealed (Part A, Section II.D.1.sss.) and related revisions were made to the associated permitting exemption (Part B, Sections II.D.2.c., and II.D.2.c.(i)-(iii)) and insignificant activities list (Part C, Section II.E.3.nnn.). EPA commented that the APEN exemption should require recordkeeping and reporting. The AQCC repealed the APEN exemption and revised the permit exemption to be consistent with current SIP approved language instead of requiring additional recordkeeping and reporting. Note that while the categorical exemption is being repealed, sources may still utilize the general one and two ton APEN exemptions found in Part A, Section II.D.1.a.

Emergency generator APEN exemption was repealed (Part A, Section II.D.1.ttt.), and related revisions were made to the associated permitting exemption (Part B, Sections II.D.2.c., and II.D.2.c.(i)-(iii)) and insignificant activities list (Part C, Section II.E.3.nnn.). EPA commented that the APEN exemption should require recordkeeping and reporting. The AQCC repealed the APEN exemption, and revised the permit exemption to be consistent with current SIP approved language instead of requiring additional recordkeeping and reporting. Note that while the categorical exemption is being repealed, sources may still utilize the general one and two ton APEN exemptions found in Part A, Section II.D.1.a.

Surface water impoundment APEN exemption was clarified (Part A, Section II.D.1.uuu.) and related revisions were made to the associated permitting exemption (Part B, Section II.D.1.m.) and insignificant activities list (Part C, Section II.E.3.yyy.). EPA commented that the APEN exemption should be clarified to confirm that the exemption applied to oil and gas produced water. In addition to making this revision, the AQCC also clarified exceptions to these exemptions and insignificant activity.

Deaerator/vacuum pump exhaust APEN exemption was repealed (Part A, Section II.D.1.xxx.) and associated revisions were made to the insignificant activities list (Part C, Section II.E.3.uuu.). EPA commented that it was unclear what these activities were. The AQCC is unaware of any source making use of this exemption, and thus has removed this exemption and associated insignificant activity.

Air curtain destructor APEN exemption removal (Part A, Section II.D.1.ffff.). EPA commented that because air curtain destructors meet the SIP approved definition of an incinerator and as such are required to submit APENs and obtain permits, that this exemption should be removed.

On February 4, 2011, EPA's action granting partial approval and partial disapproval of SIP revisions submitted to EPA in April 2003 and June 2003, was published in the Federal Register. See *76 FR 6331.* Those 2003 SIP revisions to Regulation Number 3 revised APEN exemptions and permitting exemptions in Regulation Number 3, Parts A and B, respectively. To address EPA's concerns, the following provisions that EPA disapproved or on which EPA otherwise provided comment, were revised or removed as follows:

Stationary internal combustion engines 10 ton per year permitting exemption in attainment areas (Part B, Sections II.D.1.c., and II.D.1.c.(iii)). EPA commented that Colorado did not make the anti-backsliding demonstration necessary to increase the permitting exemption threshold from 5 tons per year to 10 tons per year. The AQCC opted to revert back to the 5 tons per year threshold that EPA previously approved instead of making the necessary demonstration at this time. Note that this revision does not prevent any source from making use of the facility-wide permit exemptions found in Part B, Sections II.D.2. or II.D.3.

Non-road engine state-only requirements (Part A, Sections I.B.31.c. and I.B.31.d.). EPA commented that it could not approve provisions which are identified as state-only provisions. The AQCC agrees and has further placed "(State-only Requirement)" at the beginning of these sections to clearly identify that they are state-only provisions.

Biogenics Deferral Revisions:

On June 3, 2010, EPA's "Prevention of Significant Deterioration and Title V Greenhouse Gas (GHG) Tailoring Rule," commonly called the GHG Tailoring Rule, was published in the Federal Register. See *75 FR 31514.* EPA's GHG Tailoring Rule was designed to tailor the applicability criteria that determine which stationary sources and modification projects become subject to permitting requirements for GHGs under the Prevention of Significant Deterioration (PSD) and Title V Permitting Programs of the Clean Air Act (CAA).

On July 20, 2011, EPA's "Deferral for CO2 Emissions from Bioenergy and Other Biogenic Sources Under the Prevention of Significant Deterioration (PSD) and Title V Programs," commonly called the Biogenic Deferral, was published in the Federal Register. See *76 FR 43490.* Beginning July 1, 2011, EPA's Biogenic Deferral temporarily excludes biogenic CO2 emissions from the definition of "subject to regulation" to allow biogenic sources of carbon dioxide (CO2) emissions a three year deferral from the PSD and Title V permitting requirements; the three year deferral applies even if the source's GHG emissions exceed the threshold established in the Tailoring Rule. To maintain consistency with implementation of federal requirements associated with the Tailoring Rule and the associated Biogenic Deferral, the AQCC incorporated EPA's Biogenic Deferral into Colorado's PSD and Title V Permitting Programs, as follows:

Revise the existing definition of Subject to Regulation consistent with EPA's proposed Biogenic Deferral (Part A, Section I.B.44.b.).

Other Revisions:

In addressing the above actions, the AQCC made several additional Regulation Number 3 revisions that relate to: revising the time frame for reporting the Notice of Startup to the Division from thirty days prior to fifteen days after commencing operation, which is consistent with Colorado's House Bill 10-1042, as codified in 25-7-114.5(12)(a), C.R.S.; including NOx as a precursor to ozone in ozone significant monitoring concentration (SMC) and removing the total suspended solid SMC, both consistent with federal requirements; and making typographical, grammatical and formatting corrections.

Additional Considerations

These adopted rules are mandated by federal law and necessary to maintain EPA approval of Colorado's SIP. The revisions associated with the PM2.5 Implementation Rules and Biogenics Deferral mirror the federal requirements. While the PM2.5 Implementation Rules do allow States the opportunity to deviate from the specified PM2.5 precursor pollutants, Colorado does not have sufficient modeling and monitoring data available to support a decision to identify VOC and NH3 as PM2.5 precursors or narrow the area in which NOx is identified as a PM2.5 precursor in Colorado. The related revisions adhere to federal requirements [as required by Sections 25-7-105(1), 25-7-201(a) and 25-7-203, and 25-7-302, C.R.S.], and therefore the provisions of Sections 25-7-110.5(5) and 110.8, C.R.S. do not apply to these revisions.

With respect to EPA's SIP disapproval actions, while the AQCC must address EPA's comments, Colorado has some flexibility in addressing those comments. Here, the provisions of Sections 25-7-110.5(5) and 110.8, C.R.S. apply to this rulemaking. Thus, the AQCC makes the following determinations only as they pertain to the SIP disapproval actions, and only where the AQCC has flexibility in addressing EPA's comments.

Pursuant to 25-7-110.5(5). C.R.S., the AQCC makes the determination that:

(I) EPA's SIP disapproval actions are federal requirements that may apply to this rulemaking.

(II) The applicable federal requirements imposing emission reporting and permitting are performance based. While the AQCC must address EPA's comments, there is some flexibility in how best to address those comments.

(III) Regarding EPA's comments on the APEN exemptions, accurate actual emissions data for open burning sources, mobile sources, stationary internal combustion engines, emergency generators, oil and gas surface water impoundments, deaerator/vacuum pump exhaust, and air curtain destructors is limited, although more is known about the engines, generators and air curtain destructors. The AQCC concluded that the adopted rule will clarify and generally improve Colorado's inventory of emissions from these sources in Colorado, and thus the reporting components are essential to this effort.

(IV) With respect to APEN associated permitting exemption revisions, these revisions strike an appropriate balance between exempting small emission sources, ensuring that Colorado has a reasonably accurate inventory, as well as ensuring that reporting and permitting requirements are reasonably uniform and equitable.

(V) The AQCC is not aware of any timing issue that could justify changing the timeframe in which these rules are implemented. There are deadlines by which states are expected to implement federally mandated changes, with potential sanctions for failing to meet these deadlines.

(VI) The APEN and associated permitting exemption and insignificant activity requirements in question are not specifically designed with a margin for accommodation, but instead will rely on the opportunity for future revisions, as necessary, to adjust for uncertainty and future growth.

(VII) The adopted revisions establish reasonable equity for sources subject to the revisions by providing the same requirements for similarly situated sources.

(VIII) If revisions to the APEN and permitting exemptions and insignificant activities are not adopted, while there would be no change in cost to industry, Colorado's emissions inventory accuracy will not improve. Emissions inventories are essential tools in protecting public health and the environment. A less accurate emissions inventory may translate into a public health and welfare and environmental cost, by delaying the time necessary to improve the inventory when developing plans to address future NAAQS.

(IX) The proposed revisions include no requirements that differ from applicable federal requirements.

(X) Demonstrated technology is available to comply with the particulate matter permitting requirements. Sources are already using the control devices intended to be used to comply with this rule.

(XI) The adopted rules will contribute to prevention of pollution, by having sources more accurately assess emissions to determine if APEN reporting or permitting requirements apply. Understanding emissions is essential in preventing pollution.

(XII) Because these rules are federally mandated, no alternative rules would address the requirements in question.

Further, pursuant to 25-7-110.8(1), C.R.S., the AQCC makes the determination that:

(I) The rule is based upon reasonably available, validated, reviewed, and sound scientific methodologies, and the AQCC has considered all information submitted by interested parties.

(II) These amendments are largely administrative in nature as they relate to APEN reporting, permitting exemptions and insignificant activities.

(III) Evidence in this record supports the finding that the rule shall bring about reductions in risks to human health and the environment that justify the costs to implement and comply with the rule.

(IV) The rule is the most cost effective, provides the regulated community flexibility, and achieves any necessary reduction in air pollution.

(V) The selected regulatory alternative will maximize the air quality benefits of regulation in the most cost-effective manner.

**I.WW. Adopted December 20, 2012**

Regulation Number 3, Parts A, B, C, D, and Appendix B of Part A – revising language for conformity with the New Source Review (NSR) Program and approved State Implementation Plan ("SIP"); streamlining the permit issuance process; and correcting other typographical, grammatical, and formatting errors.

This Statement of Basis, Specific Statutory Authority, and Purpose complies with the requirements of the Colorado Administrative Procedures Act, Section 24-4-103, C.R.S., and the Colorado Air Pollution Prevention and Control Act, Sections 25-7-110 and 25-7-110.5, C.R.S.

**Specific Statutory Authority**

The Colorado Air Pollution Prevention and Control Act, Sections 25-7-105(1)(a), 25-7-201 though 25-7-206, 25-7-210, 25-7-301, and 25-7-302, C.R.S. authorize the Air Quality Control Commission ("Commission") to promulgate a comprehensive State Implementation Plan ("SIP") which will assure attainment and maintenance of national ambient air quality standards ("NAAQS") and prevent significant deterioration ("PSD") of air quality in conformance with the Federal and Colorado Acts. Section 25-7-105(1)(c) further states that definitions used in the PSD program shall not differ from definitions pertaining to the federal PSD program in the Clean Air Act Section 169. Section 25-7-105(12) authorizes the Commission to promulgate regulations necessary to implement the provisions of the emission notice, construction permit, and Title V programs. Section 25-7-106(7)(a) authorizes the Commission to develop a program to apply and enforce relevant provisions of the SIP including the imposition of any fees necessary to administer the program. Section 25-7-114.7 requires owners or operators of air pollution sources to pay permit application processing fees. Section 25-7-114.4 authorizes the Commission to promulgate regulations necessary and proper for the orderly and effective administration of construction permits and renewable operating permits. And, Section 25-7-114.5 authorizes the Commission to designate which projects or activities requiring a construction permit application warrant public comment.

**Basis and Purpose**

The Commission revised the Permit Processing Fees, Section VI.B.5., to streamline construction permit issuance by allowing the Division to issue a construction permit prior to receiving full payment for the assessed permit processing fees. Currently, the Division cannot issue an approved construction permit until the Division receives the applicant's complete processing fees payment, which delays the applicant's ability to commence construction due to the invoicing and payment process. This revision eliminates this delay as, under the revised issuance process, applicants will receive the approved construction permit and be able to commence construction during the invoicing and payment process. Also under the revised issuance process, failure to pay the assessed permit processing fees may result in late fees according to Section 25.7.114.7(2)(a)(I)(A.5), C.R.S. and/or revocation of the permit utilizing the current Division revocation procedures. Applicants will be notified of the potential consequences of nonpayment as well as corrective actions in the written request for processing fees and the written request for late processing fees, if applicable. This revision will not negatively impact permit applicants who pay their permit processing fees on time.

The Commission amended Appendix B to Part A to identify non-criteria reportable pollutants first alphabetically by Chemical Bin ("BIN") and then by chemical abstract service ("CAS") number to increase the clarity and usability of the Appendix.

The Commission amended the Part B, Section III.C.1.a., Public Comment and Hearing Requirements to include attainment/maintenance areas.

The Commission removed the italic font and deleted the underlined text throughout the regulation, primarily in Part D, in response to EPA's approval of the corresponding language into Colorado's SIP on January 9, 2012 (*77 Fed. Reg. 1027*), and April 10, 2012 (*77 Fed. Reg. 21453*). The provisions under review by EPA were italicized to indicate the text was not yet effective while other text was underlined to indicate it would only be effective until EPA approved the italicized text into the SIP. Based on EPA's final actions in January and April, the italicized rule language, minus the underlined text, became effective on May 10, 2012. Paragraph (b) of the definition of Representative Actual Annual Emissions, II.A.40.5, was also deleted to conform with the NSR Program and SIP because, though not underlined in Regulation Number 3, the NSR Program removed the entire definition from 40 C.F.R. Part 51.

The Commission corrected the PM2.5 Major Source Baseline Date, Part D, Section II.A.23.c., which was inadvertently adopted as October 20, 2011, to reference the major source baseline date of October 20, 2010, set by EPA on October 20, 2010 (*75 Fed. Reg. 64864*).

The Commission corrected a regulatory reference in Requirements Applicable to Nonattainment Areas, Part D, Section V.A.6., to reference Section XIII.A. Section V.A.6. currently refers Federal Land Manager involvement to Section XII.A., Innovative Control Technology, instead of XIII.A., Federal Class I Areas.

**I.XX. Adopted February 20, 2014**

Regulation Number 3, Parts A, B, C, D, and Appendices A and B of Part A – removing requirements for a source subject to a NSPS or NESHAP/MACT incorporated into Regulation Number 6, Part A or Number 8, Parts A, C, D, and E to file an APEN and obtain a minor source permit regardless of whether the source's emissions exceed the reporting of permitting thresholds ("catch-all provisions"); simplifying the Part A, Appendix A de minimis determination for non-criteria reportable pollutants; removing the crude oil storage tank exemptions; and correcting other typographical, grammatical, and formatting errors.

This Statement of Basis, Specific Statutory Authority, and Purpose complies with the requirements of the Colorado Administrative Procedures Act, C.R.S. § 24-4-103, the Colorado Air Pollution Prevention and Control Act, C.R.S. §§ 25-7-110 and 25-7-110.5, and the Air Quality Control Commission's ("Commission") Procedural Rules.

Specific Statutory Authority

The Colorado Air Pollution Prevention and Control Act § 25-7-105(1) directs the Commission to promulgate such rules and regulations as are consistent with the legislative declaration set forth in Section 25-7-102 and are necessary for the proper implementation and administration of Article 7. C.R.S. § 25-7-105(1)(a)(I) authorizes the Commission to revise Colorado's State Implementation Plan whenever necessary and appropriate. C.R.S. § 25-7-105(1) authorizes the Commission to promulgate regulations necessary to implement the provisions of the Colorado emission notice, minor source permit, and Title V programs. C.R.S. § 109(3) authorizes the Commission to promulgate emissions control regulations pertaining to the storage and transfer of petroleum products and other VOCs. C.R.S. § 25-7-109.3(3)(c) directs the Commission to exempt classes of minor or insignificant sources of emissions of hazardous air pollutants from the Colorado hazardous air pollutant control and reduction program requirements. Section 25-7-109.3(5)(c) directs the Commission to establish de minimis emission levels for each hazardous air pollutant beneath which emissions are considered to be of minor significance.

Basis and Purpose

As part of a larger rule revision package, the Commission incorporated the federal Standards of Performance for Crude Oil and Natural Gas Production, Transmission, and Distribution found in 40 C.F.R. Part 60, Subpart OOOO ("NSPS OOOO") in full, as amended, into Regulation Number 6, Part A and made the corresponding revisions to Regulation Number 3 described below. The Commission also revised Regulation Number 7 for consistency with and to complement NSPS OOOO and to include additional emission control measures for oil and gas production operations and equipment. Finally, the Commission revised Regulation Number 7 storage tank control requirements with the intent that industry could utilize such controls when determining whether a storage tank was subject to NSPS OOOO.

These Regulation Number 3 revisions were important to the comprehensive proposal because they reduced reporting and permitting burdens that would otherwise occur when NSPS OOOO was adopted in full. These Regulation Number 3 revisions apply broadly to all emission sources and are not solely applicable to oil and gas operations.

*Catch-all Provisions*

The Commission removed the catch-all provisions in Part A, Sections II.D.1. and Part B, Sections II.A.5. and II.D. so that sources subject to a New Source Performance Standard ("NSPS"), National Emission Standard for Hazardous Air Pollutants ("NESHAP"), or Maximum Achievable Control Technology ("MACT") incorporated into Regulation Numbers 6 or 8 are not automatically required to file an APEN and obtain a minor source permit, regardless of whether the source's uncontrolled actual emissions exceeded reporting or permitting thresholds.

These rule changes reduced the administrative reporting and permitting burden for the Division and the regulated community, both for sources subject to NSPS OOOO and other future NSPS and NESHAP/MACT. For example, NSPS OOOO affected facilities with uncontrolled actual emissions less than the reporting and permitting thresholds no longer automatically have to file APENs and obtain minor source permits. This reduced permitting burden will allow the Division to reallocate permitting resources to more complicated sources with the greater impact to Colorado's air quality, as well as to develop and maintain other guidance and compliance assistance tools. The environmental impacts of this revision were minimal and no emissions increases were anticipated because the revisions did not exempt any source from complying with the requirements of an applicable NSPS, NESHAP, or MACT.

*Part A, Appendix A*

The Commission revised the Part A, Appendix A method for determining non-criteria reportable pollutant de minimis levels in order to standardize the de minimis reporting threshold and set a 250 pounds per year threshold for all non-criteria reportable pollutants. This revised threshold applies statewide. This revision simplified non-criteria reportable pollutant reporting by eliminating the determination of reporting level based on release point, property boundary, and pollutant bin. Prior to revision, these reporting determinations were complicated and confusing, and sources often utilized the most stringent reporting threshold with the applicable Bin category, rather than attempt to follow the methodology. This revision increased regulatory clarity and reduced the administrative reporting burdens for both the Division and the regulated community by simplifying the process. No emissions increases were anticipated as a result of this revision because this revision was administrative in nature and did not change the applicability of controls or regulations to sources.

*Crude Oil Storage Tanks*

The Commission removed the crude oil storage tank permitting exemptions in Part B, Section II.D.1.n. and Part C, Section II.E.3.ddd. The emissions from crude oil storage tanks can be significant and permitting exemptions are meant to be limited to emission points with negligible impacts on air quality.

*Crude Oil and Condensate Truck Loading Equipment*

The Commission corrected an error in Part B, Section II.D.1.l. by removing the last sentence of the crude oil truck loading equipment minor source permitting exemption. In 2006, the Regulation Number 3 APEN exemption inadvertently merged the original exemption language with the 2002 exemption revision so that in 2008, when the Commission removed the APEN exemption to build the emissions inventory and moved the exemption in Part B to maintain the associated permitting exemption, the erroneous language persisted. This revision corrected that error.

**I.YY. Adopted November 20, 2014**

This Statement of Basis, Specific Statutory Authority, and Purpose complies with the requirements of the Colorado Administrative Procedures Act, C.R.S. § 24-4-103, the Colorado Air Pollution Prevention and Control Act, C.R.S. §§ 25-7-110 and 25-7-110.5, and the Air Quality Control Commission's ("Commission") Procedural Rules.

Basis

Regulation Number 3, Part F – revising the NOx emission limit, compliance date and BART determination for Tri-State Generation and Transmission Association ("Tri-State"), Craig Station Unit 1.

Specific Statutory Authority

The Colorado Air Pollution Prevention and Control Act, C.R.S. § 25-7-105(1) directs the Commission to promulgate such rules and regulations as are consistent with the legislative declaration set forth in Section 25-7-102 and are necessary for the proper implementation and administration of Article 7, including a comprehensive state implementation plan which will prevent significant deterioration of air quality. Section 25-7-109(1)(a) authorizes the Commission to require the use of air pollution controls. Section 109(2) authorizes the Commission to adopt emission control regulations pertaining to visible pollutants and nitrogen oxides.

Purpose

The Colorado Air Quality Control Commission ("Commission") revises Regulation Number 3, Part F, Section VI., containing the Regional Haze Best Available Retrofit Technology ("BART") determinations that the Commission adopted and the EPA approved as part of Colorado's Regional Haze State Implementation Plan ("SIP").

After EPA approved Colorado's Regional Haze SIP, WildEarth Guardians and the National Parks Conservation Association challenged portions of this approval by filing suit against EPA in the Tenth Circuit. As part of this lawsuit, the plaintiffs contested the nitrogen oxides ("NOx") provisions for Craig Station Unit 1. In furtherance of settlement of this litigation, the Commission has revised Regulation Number 3, Part F, Section VI. to strengthen the NOx emission limit and set the compliance deadline for Craig Station Unit 1. The Commission revised Craig Station Unit 1's BART determination for NOx by revising the NOx emission limit from 0.28 lb/MMBtu to 0.07 lb/MMBtu, and revising the associated compliance deadline from January 30, 2018, to August 31, 2021. The Commission also clarified that compliance with the specified emission limits and compliance dates for both Units 1 and 2 constitute BART for this facility.

In addition to the regulatory changes described above, the Division proposes to make corresponding changes to Colorado's Regional Haze SIP: Chapter 6 - Best Available Retrofit Technology; Chapter 9 – Long Term Strategy; and Appendix C – Technical Support for the BART Determinations. The revisions to the Regional Haze SIP do not impact the emission limits or compliance deadline for Craig Station Unit 2. The revised chapters fully replace previously adopted SIP chapters.

Findings of Fact

Colorado's Regional Haze SIP revisions are consistent with EPA's federal requirements under the Regional Haze rule. Accordingly, the revisions do not exceed the requirements of the federal act or differ from the federal act or rules. However, to the extent that these revisions could be viewed as exceeding or differing from the federal act, the Commission determines in accordance with C.R.S. § 25-7-110.5(5)(b):

(I) Colorado's Regional Haze SIP was drafted in accordance with EPA's Regional Haze Rule. The Regional Haze Rule provides states flexibility in how states may consider the federal statutory and regulatory factors when determining BART and reasonable progress goals.

(II) EPA's regional haze requirements are performance based. The Regional Haze Rule sets forth factors the states must consider when determining BART for sources reasonably anticipated to cause or contribute to the impairment of visibility in federal Class I areas. States have the discretion to select the appropriate controls for such sources.

(III) EPA's Regional Haze Rule guides how states must determine BART for their BART-eligible sources. However, state discretion is a cornerstone of the Regional Haze Rule (*70 FR 39137*). Colorado considered Colorado's issues of concern when developing these revisions.

(IV) The adopted revisions will improve Tri-State's ability to comply with the goals of the Regional Haze Rule while preventing or reducing the need for costly retrofits potentially required in Colorado's next reasonable progress planning period.

(V) The Regional Haze Rule requires source to comply with the BART determinations as expeditiously as possible but no later than five years after EPA approves the SIP. Concerning this revision, the Division must submit a proposed SIP revision to EPA no later than July 31, 2015, and EPA must take final action on the proposed SIP revision by December 31, 2016. The revised compliance deadline for Craig Station Unit 1 of August 31, 2021, is slightly less than five years after EPA's approval, which is within the time frame for implementation set by the Regional Haze Rule.

(VI) The adopted rule will assist in establishing and maintaining a reasonable margin for accommodation of uncertainty and future growth.

(VII) The adopted rule establishes reasonable equity for sources because the Regional Haze Rule applies the same standards for determining BART to all BART-eligible sources. BART determinations are source specific and different controls and emission limits are to be expected.

(VIII) If the revisions were not adopted, litigation would continue concerning the regional haze requirements for Craig Station that would entail associated costs and uncertainties as to the outcome.

(IX) These revisions do not modify the currently approved procedural, reporting, or monitoring requirements in Colorado's Regional Haze SIP.

(X) Demonstrated technology is available to comply with the revised NOx emission rate for Craig Station Unit 1.

(XI) The revisions will contribute to further reductions of NOx emissions and therefore contribute to the prevention of pollution.

(XII) Neither an alternative rule nor a no action alternative would address or achieve the emission reductions to be achieved through these revisions. Further, failure to adopt the revisions could result in further expensive and time consuming litigation concerning Colorado's regional haze provisions for Craig Station Unit 1.

As part of adopting the revisions to Regulation Number 3, Part F, Section VI., the Commission has taken into consideration each of the factors set forth in C.R.S. § 25-7-109(1)(b).

To the extent that C.R.S. § 25-7-110.8 requirements apply to this rulemaking, and after considering all the information in the record, the Commission hereby makes the determination that:

(I) These rules are based upon reasonably available, validated, reviewed, and sound scientific methodologies, and the Commission has considered all information submitted by interested parties.

(II) Evidence in the record supports the finding that the rules shall result in a demonstrable reduction of NOx emissions.

(III) Evidence in the record supports the finding that the rules shall bring about reductions in risks to human health and the environment that justify the costs to implement and comply with the rules.

(IV) The rules are the most cost-effective to achieve the necessary reduction in air pollution and provide the regulated entity flexibility.

(V) The selected regulatory alternative will maximize the air quality benefits of regulation in the most cost-effective manner.

The revisions also correct typographical, grammatical, and formatting errors.

**I.ZZ. Adopted January 21, 2016**

Regulation Number 3, Part A, Section I.B.44. – revising GHG permitting thresholds.

This Statement of Basis, Specific Statutory Authority and Purpose complies with the requirements of the Colorado Administrative Procedure Act Sections 24-4-103, C.R.S., the Colorado Air Pollution Prevention and Control Act Sections 25-7-110 and 25-7-110.5, C.R.S. ("the Act"), and the Air Quality Control Commission's ("Commission") Procedural Rules.

Basis

The Commission revised the definition of "subject to regulation" to correspond to revisions to the federal definition of subject to regulation.

Specific Statutory Authority

The Colorado Air Pollution Prevention and Control Act, Sections 25-7-105(1)(a), 25-7-201 though 25-7-206, 25-7-210, 25-7-301, and 25-7-302, C.R.S. authorize the Commission to promulgate a comprehensive State Implementation Plan ("SIP") which will assure attainment and maintenance of national ambient air quality standards ("NAAQS") and prevent significant deterioration ("PSD") of air quality in conformance with the Federal and Colorado Acts. Section 25-7-105(1)(c) further requires the Commission to promulgate a PSD program in conformity with federal requirements, including definitions that do not differ from the federal definitions.

Purpose

In 2014, the United States Supreme Court held that EPA could not treat GHG as a pollutant for purposes of defining a "major emitting facility" (or a "modification" thereof) for Prevention of Significant Deterioration ("PSD") or a "major source" for Title V, essentially invalidating the Step 2 GHG permitting thresholds in EPA's Tailoring Rule. (see Util. Air Regulatory Grp. v. EPA, 134 S. Ct. 2427 (2014)) In 2015, the Court of Appeals vacated EPA regulations to the extent that they required a stationary source obtain a PSD or Title V permit solely because the source emitted GHG in excess of applicable GHG-major source thresholds. (see Coalition for Responsible Regulation v. EPA, Nos. 09-1322, 10-073, 10-1092, 10-1167 (2015)) On August 19, 2015 (80 Fed. Reg. 50199), EPA issued a final rule that removed the Step 2 GHG permitting thresholds from the definitions of subject to regulation at 40 CFR Sections 51.166 and 52.21.

In response to the court decisions and EPA's corresponding revisions, the Commission revised Section I.B.44.e. to correspond to the federal definition of subject to regulation.

Further, the Commission corrected any typographical, grammatical and formatting errors found within the regulation.

**I.AAA. Adopted October 12, 2016**

Regulation Number 3, Part D, Sections II.A.22.b., II.A.25.b., and II.A.44.a.

This Statement of Basis, Specific Statutory Authority and Purpose complies with the requirements of the Colorado Administrative Procedure Act Sections 24-4-103, C.R.S. and the Colorado Air Pollution Prevention and Control Act Sections 25-7-110 and 25-7-110.5, C.R.S. ("the Act").

Basis

The Commission revised the definition of "major stationary source" contained in Regulation Number 3, Part D, Section II. to include the ozone nonattainment area major source thresholds, consistent with federal requirements. The Commission also revised the definitions of "major emission unit" and "significant" in Regulation Number 3, Part D, Section II.

Statutory Authority

The Colorado Air Pollution Prevention and Control Act, Sections 25-7-105(1)(a), 25-7-301, and 25-7-302, C.R.S. authorize the Commission to promulgate a comprehensive State Implementation Plan ("SIP") which will assure attainment and maintenance of national ambient air quality standards ("NAAQS") in conformance with the Federal and Colorado Acts. Section 25-7-105(12) authorizes the Commission to promulgate regulations necessary to implement the provisions of the emission notice, construction permit, and Title V programs. Pursuant to Section 25-7-106, C.R.S., the Commission has the maximum flexibility in establishing an air quality control program and may promulgate regulations as necessary or desirable to carry out that program.

Purpose

**Major Stationary Source Definition**

Regulation Number 3, Part D, concerning Major Stationary Source New Source Review ("NSR") and Prevention of Significant Deterioration ("PSD"), applies statewide to any new or existing major stationary source (Section I.) and it has been fully incorporated into Colorado's SIP. If a source is a "major stationary source" as defined in Section II.A.25.b., then it will need to comply with Sections V. (Requirements Applicable to Nonattainment Areas) and VI. (Requirements applicable to attainment and unclassifiable areas and pollutants implemented under Section 110 of the Federal Act (PSD Program)) of Part D, as applicable.

A major stationary source is defined as, "Any stationary source of air pollutants that emits, or has the potential to emit 100 tons per year or more of any regulated NSR pollutant for which the area is nonattainment." Unlike the federal definition, Colorado's definition of "major stationary source" does not step-down the thresholds for determining what is a major source based on ozone nonattainment area classification. *See* 40 C.F.R. § 51.165(a)(1)(iv)(A)(1) and 40 C.F.R. Part 51, Appendix S. Thus, if an ozone nonattainment area were ever classified or reclassified as serious or severe, in order to maintain permitting authority, Colorado would need to adopt the same lower major stationary source thresholds that would apply on a federal basis before permitting new or modified sources. Therefore, in order to ensure consistency with federal definitions and to provide regulatory certainty by avoiding any disruption to the permitting process should Colorado's ozone nonattainment area ever be reclassified to a more stringent classification beyond a moderate nonattainment area, the Commission has revised the definition of "major stationary source" contained in Part D, Section II.A.25.b. to include the ozone nonattainment area major source thresholds.

**Major Emissions Unit Definition**

Currently, Section II.A.22.b. defines a major emissions unit as, "Any emissions unit that emits or has the potential to emit an amount that is equal to or greater than the major stationary source threshold (as defined in Section II.A.25. of this part) for the [plant-wide applicability limitation (PAL)] pollutant for nonattainment areas." The definition of major emissions unit in Section II.A.22.b. then goes on to provide an example of when an emissions unit would be a major emissions unit for volatile organic compounds. This example is not required to maintain consistency with federal definitions and it does not provide additional clarity to the regulation. Therefore, the Commission is removing this example.

**Significant Definition**

Currently, the definition of significant contained in Section II.A.44.a. (in reference to a net emissions increase or the potential of a source to emit air pollutants) contains emission rates in tons per year, but it does not contain emission rates pertaining to serious, severe or extreme ozone nonattainment areas. In order to ensure consistency with federal definitions and provide certainty by avoiding any disruption in the permitting process, the Commission is adding emission rates for serious, severe and extreme ozone nonattainment areas.

Further, the Commission corrected any typographical, grammatical and formatting errors found within the regulation.

**I.BBB. Adopted December 15, 2016**

Regulation Number 3, Part F – Revising the BART and Reasonable Progress determinations for Craig Station Unit 1 ("Craig Unit 1") and Nucla ("Nucla").

This Statement of Basis, Specific Statutory Authority, and Purpose complies with the requirements of the Colorado Administrative Procedures Act, C.R.S. § 24-4-103, the Colorado Air Pollution Prevention and Control Act, C.R.S. §§ 25-7-110 and 25-7-110.5, and the Air Quality Control Commission's ("Commission") Procedural Rules.

Basis

Regulation Number 3, Part F – Revising the BART and Reasonable Progress determinations for Craig Unit 1 and Nucla, respectively.

Specific Statutory Authority

The Colorado Air Pollution Prevention and Control Act, C.R.S. § 25-7-105(1) directs the Commission to promulgate such rules and regulations as are consistent with the legislative declaration set forth in Section 25-7-102 and are necessary for the proper implementation and administration of Article 7, including a comprehensive state implementation plan which will prevent significant deterioration of air quality. Section 25-7-109 authorizes the Commission to adopt emission control regulations pertaining to air pollutants.

Purpose

The Colorado Air Quality Control Commission ("Commission") makes targeted revisions to portions of Regulation Number 3, Part F, Section VI., containing the Regional Haze Best Available Retrofit Technology ("BART") and Reasonable Progress determinations that the Commission previously adopted as part of Colorado's Regional Haze State Implementation Plan ("SIP").

After the U.S. Environmental Protection Agency ("EPA") approved Colorado's Regional Haze SIP, WildEarth Guardians and the National Parks Conservation Association ("NPCA") challenged portions of the approval by filing suit in the Tenth Circuit (Guardians v. EPA, No. 13-9520 and NPCA v. EPA, No. 13-9525). As part of that lawsuit, the plaintiffs contested the nitrogen oxides ("NOX") provisions for Craig Unit 1, which is owned, in part, and operated by Tri-State Generation and Transmission Association, Inc. ("Tri-State"). In furtherance of settlement of that litigation, in 2014, the Commission approved revisions to Regulation Number 3, Part F, Section VI. to change the Craig Unit 1 NOX emission limit from 0.28 lb/MMBtu to 0.07 lb/MMBtu, and set the associated compliance deadline for Craig Station Unit 1 as August 31, 2021.

Since the Commission approved the 2014 revisions to Regulation Number 3, Part F and Colorado's Regional Haze SIP, an agreement has been reached involving Craig Unit 1 and Nucla Station ("Nucla"). The agreement includes the following commitments:

(I) Craig Unit 1 will either close on or before December 31, 2025 or cease burning coal no later than August 31, 2021 with the option to convert the unit to natural-gas firing by August 31, 2023;

(II) In the case of a conversion to natural-gas firing, a 30-day rolling average NOX emission limit of 0.07 lb/MMBtu will be effective after August 31, 2021;

(III) For both scenarios, Craig Unit 1 will be subject to a NOX emission limit of 0.28 lb/MMBtu, on a 30 day rolling average, effective January 1, 2017 (first compliance date January 31, 2017), until converting to natural gas or permanently shutting down;

(IV) Craig Unit 1 will be subject to an annual NOX emission limit of 4,065 tons per year effective on December 31, 2019 on a calendar year basis beginning in 2020;

(V) Nucla will close on or before December 31, 2022; and

(VI) Nucla will be subject to an annual NOX emission limit of 952 tons per year effective January 1, 2020 on a calendar year basis beginning in 2020.

The Air Pollution Control Division ("Division") conducted a BART reassessment for Craig Unit 1 and Reasonable Progress review for Nucla, respectively, taking into account the agreement. The agreement reflects a changing industry, economic, and regulatory landscape that does not necessarily favor the installation of costly post-combustion retrofit controls on aging coal-fired electric generating units. The agreement and these revisions will also result in greater emissions reductions than would result from the previously approved SIP. The Commission's adoption of these revisions will result in further reductions of visibility impairing pollutants, in addition to providing other environmental co-benefits.

In accordance with the BART reassessment and Reasonable Progress review, the Commission revises 3, Part F, Section VI to reflect the applicable elements of the agreement described herein.

In addition to the regulatory changes to Regulation Number 3, Part F, the Commission revises corresponding portions of Colorado's Regional Haze SIP: Chapter 6 – Best Available Retrofit Technology; Chapter 8 – Reasonable Progress; Appendix C – Technical Support for the BART Determinations; and Appendix D – Technical Support for the Reasonable Progress Determinations. The revised chapters fully replace previously adopted SIP chapters. The revisions to Colorado's Regional Haze SIP, Chapter 6 – Best Available Retrofit Technology and Appendix C – Technical Support Document - for the BART Determinations, include, among other things, revised cost comparisons as part of the NOx BART reassessment for Craig Unit 1. The Commission is aware of the fact that there are differing views among parties to the recent agreement as to what the appropriate amortization periods should be for use in calculating the cost effectiveness of SNCR and SCR in Scenario 1 (closure on or before December 31, 2025). The Commission finds that regardless of the amortization period used, under Scenario 1, both SNCR and SCR are not cost effective when the remaining useful life is shortened.

The revisions also correct any typographical, grammatical, and formatting errors.

Findings of Fact

Colorado's Regional Haze SIP revisions are consistent with EPA's federal requirements under the Regional Haze rule. Accordingly, the revisions do not exceed the requirements of the federal act or differ from the federal act or rules. However, to the extent that these revisions could be viewed as exceeding or differing from the federal act, the Commission determines in accordance with C.R.S. § 25-7-110.5(5)(b):

(I) Colorado's Regional Haze SIP was drafted in accordance with EPA's Regional Haze Rule. The Regional Haze Rule provides states flexibility in how states may consider the federal statutory and regulatory factors when determining BART and reasonable progress goals.

(II) EPA's regional haze requirements are performance based. The Regional Haze Rule sets forth factors the states must consider when determining BART for sources reasonably anticipated to cause or contribute to the impairment of visibility in federal Class I areas. States have the discretion to select the appropriate controls for such sources.

(III) EPA's Regional Haze Rule guides how states must determine BART for their BART-eligible sources. However, state discretion is a cornerstone of the Regional Haze Rule (70 FR 39137). Colorado considered Colorado's issues of concern when developing these revisions.

(IV) The adopted revisions will improve industry's ability to comply with the goals of the Regional Haze Rule in a more cost-effective way, by increasing certainty and preventing or reducing the need for costly retrofits.

(V) The timing of the adopted revisions has been considered. The timeframe of the adopted revisions allows for the avoidance of costly retrofits.

(VI) The adopted rule will assist in establishing and maintaining a reasonable margin for accommodation of uncertainty and future growth.

(VII) The adopted rule establishes reasonable equity for sources because the Regional Haze Rule applies the same standards for determining BART to all BART-eligible sources. BART determinations are source specific and different controls and emission limits are to be expected.

(VIII) Adoption of a more stringent rule would not reduce costs upon other entities.

(IX) These revisions do not modify the currently approved procedural, reporting, or monitoring requirements in Colorado's Regional Haze SIP.

(X) Technology is available to comply with the adopted revisions. The technology to convert to natural gas is a demonstrated and already utilized technology.

(XI) The revisions will lead to further reductions of air pollutant emissions, contribute to the prevention of pollution, and represent a more cost-effective environmental gain.

(XII) Neither an alternative rule nor a no action alternative would address or achieve the emission reductions to be achieved through these revisions. Further, failure to adopt the revisions could result in expensive and time consuming retrofits or litigation.

As part of adopting the revisions to Regulation Number 3, Part F, Section VI., the Commission has taken into consideration each of the factors set forth in C.R.S. § 25-7-109(1)(b).

To the extent that C.R.S. § 25-7-110.8 requirements apply to this rulemaking, and after considering all the information in the record, the Commission hereby makes the determination that:

(I) These rules are based upon reasonably available, validated, reviewed, and sound scientific methodologies, and the Commission has considered all information submitted by interested parties.

(II) Evidence in the record supports the finding that the rules shall result in a demonstrable reduction of air pollutant emissions.

(III) Evidence in the record supports the finding that the rules shall bring about reductions in risks to human health and the environment that justify the costs to implement and comply with the rules.

(IV) The rules are the most cost-effective to achieve the necessary reduction in air pollution and provide the regulated community flexibility.

(V) The selected regulatory alternative will maximize the air quality benefits of regulation in the most cost-effective manner.

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**Editor's Notes**

**History**

Part A Section VI.D, Part F Section I.MM eff. 11/30/2007.

Part E (Best Available Retrofit Technology (BART) eff. 03/01/2008.

Entire rule eff. 04/30/2008.

Part F Section IV.B; Part G Section I.PP eff. 06/30/2008.

Part A Section VI.D, Part G Section I.QQ eff. 10/30/2008.

Part A Section II.D, Part B Section II D, Part C Section II E, Part F Section VI.B, Part G Sections I.RR, I.SS eff. 01/30/2009.

Entire rule eff. 12/15/2010.

Part D Section XIV.F; Part F, Part G Section I.UU eff. 02/14/2011.

Part A Sections I.B, II.C, II.D; Part B Sections II.D, III.G; Part C Sections I.A, II.E, X.A, XII.A; Part D Sections II.A, III.B, V.A, VI.A, VI.B, VI.D, X.A, XIII.B, XIII.D; Part F Sections I, III.A, IV.A, VI.B, VI.C, Part G Sections I.C, I.VV eff. 12/15/2011.

Part A Sections I.A, I.B.7, I.B.14 – I.B.16, I.B.28, I.B.31.d, I.B.38, I.B.43, II.D.1.dddd, V.I, VI.A – VI.B, Appendix B, Part B Section III.C.1.a, Part C Sections I.A.7, XIV, Part D Sections I – II, V.A.1 – V.A.7, VI.A, VI.B, XV, Part F, Part G Section I.WW eff. 02/15/2013.

Part A Sections II.B.3.b, II.D.1, II.D.1.b, Appendix A, Part B Sections II.A.5, II.D, II.D.1, II.D.1.l, II.D.1.n, Part C Section II.E.3.ddd, Part D Section XV.F.5, Part F Sections VII.A.3, VII.B.1.a, VII.B.1.b, VII.B.1.b.(ii), Part G Section I.XX eff. 04/14/2014.

Part A Sections I.B, II.C, V.C, V.I, VI.C, Appendix A, Appendix B, Part B Section III.C, Part C Section VI.A – VI.B, XII.B, Part D Sections I – II, V – VI, XV, Part G Section I.YY eff. 10/15/2014.

Part F Section VI.A, Part G Section I.YY eff. 01/14/2015.

Part A Section I.B.44.e., Part G Section I.ZZ eff. 03/16/2016.

Part D, Sections II.A.22.b, II.A.25.b, II.A.44.a, Part G, Section I.AAA eff. 11/30/2016.

Part F Section VI, Part G Section I.BBB eff. 02/14/2017.

**Annotations**

**Air Pollution Control Division did not err by obtaining and reviewing the original visibility data from the National Park Service** because the Division reviewed and analyzed that information in ultimately arriving at its own conclusion. *Citizens for Clean Air & Water v. Colo. Dep't of Pub. Health & Env't, 181 P.3d 393 (2008).*

BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

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| Federal Power Act Section 202(c) | ) |
| Emergency Order: Tri-State | ) |
| Generation and Transmission | ) |
| Association, Platte River Power | ) |
| Authority, Salt River Project, | ) |
| PacifiCorp, and Xcel Energy | ) |

Exhibit to
Motion to Intervene and Request for Rehearing and Stay of
Public Interest Organizations

Exhibit 2-67:
EPA $NO_2$ Information

# Basic Information about NO2

www.epa.gov/no2-pollution/basic-information-about-no2

July 6, 2016




On This Page:


- What is $NO_2$ and how does it get in the air?
- What are the harmful effects of $NO_2$?
- What is being done to reduce $NO_2$ pollution?


## What is $NO_2$ and how does it get in the air?

Nitrogen Dioxide ($NO_2$) is one of a group of highly reactive gases known as oxides of nitrogen or nitrogen oxides ($NO_x$). Other nitrogen oxides include nitrous acid and nitric acid. $NO_2$ is used as the indicator for the larger group of nitrogen oxides.

$NO_2$ primarily gets in the air from the burning of fuel. $NO_2$ forms from emissions from cars, trucks and buses, power plants, and off-road equipment.

## Effects of $NO_2$

### Health effects

Breathing air with a high concentration of $NO_2$ can irritate airways in the human respiratory system. Such exposures over short periods can aggravate respiratory diseases, particularly asthma, leading to respiratory symptoms (such as coughing, wheezing or difficulty breathing), hospital admissions and visits to emergency rooms. Longer exposures to elevated concentrations of $NO_2$ may contribute to the development of asthma and potentially increase susceptibility to respiratory infections. People with asthma, as well as children and the elderly are generally at greater risk for the health effects of $NO_2$.

$NO_2$ along with other $NO_x$ reacts with other chemicals in the air to form both particulate matter and ozone. Both of these are also harmful when inhaled due to effects on the respiratory system.

> Learn more about Particulate Matter and Ozone.

### Environmental effects

$NO_2$ and other $NO_x$ interact with water, oxygen and other chemicals in the atmosphere to form acid rain. Acid rain harms sensitive ecosystems such as lakes and forests.

> Learn more about Acid Rain.

The nitrate particles that result from $NO_x$ make the air hazy and difficult to see though. This affects the many national parks that we visit for the view.

> Learn more about Visibility and Haze.

$NO_x$ in the atmosphere contributes to nutrient pollution in coastal waters.

> Learn more about Nutrient Pollution.

## What is being done to reduce $NO_2$ pollution?

EPA's national and regional rules to reduce emissions of $NO_2$ and $NO_x$ will help state and local governments meet the National Ambient Air Quality Standard (NAAQS).

> Learn about how air quality standards help reduce $NO_2$

EPA identifies areas where the air quality does not meet the national $NO_2$ standards. For these areas, state, local, and tribal governments develop plans to reduce the amount of $NO_2$ in the air.

Learn more about $NO_2$ air quality designations and state implementation plans (SIPs).

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Exhibit 2-68:
EPA Sulfur Dioxide Information

# Sulfur Dioxide Basics

www.epa.gov/so2-pollution/sulfur-dioxide-basics

June 2, 2016





- What is $SO_2$ and how does it get in the air?
- What are the harmful effects of $SO_2$?
- What is being done to reduce $SO_2$ pollution?


## What is $SO_2$ and how does it get in the air?

### What is $SO_2$?

EPA's national ambient air quality standards for $SO_2$ are designed to protect against exposure to the entire group of sulfur oxides ($SO_x$). $SO_2$ is the component of greatest concern and is used as the indicator for the larger group of gaseous sulfur oxides ($SO_x$). Other gaseous SOx (such as $SO_3$) are found in the atmosphere at concentrations much lower than $SO_2$.

Control measures that reduce $SO_2$ can generally be expected to reduce people's exposures to all gaseous $SO_x$. This may have the important co-benefit of reducing the formation of particulate sulfur pollutants, such as fine sulfate particles.

Emissions that lead to high concentrations of $SO_2$ generally also lead to the formation of other $SO_x$. The largest sources of $SO_2$ emissions are from fossil fuel combustion at power plants andother industrial facilities.

### How does $SO_2$ get in the air?

The largest source of $SO_2$ in the atmosphere is the burning of fossil fuels by power plants and other industrial facilities. Smaller sources of $SO_2$ emissions include: industrial processes such as extracting metal from ore; natural sources such as volcanoes; and locomotives, ships and other vehicles and heavy equipment that burn fuel with a high sulfur content.

## What are the harmful effects of $SO_2$?

$SO_2$ can affect both health and the environment.

### What are the health effects of $SO_2$?

Short-term exposures to $SO_2$ can harm the human respiratory system and make breathing difficult. People with asthma, particularly children, are sensitive to these effects of $SO_2$.

$SO_2$ emissions that lead to high concentrations of $SO_2$ in the air generally also lead to the formation of other sulfur oxides ($SO_x$). $SO_x$ can react with other compounds in the atmosphere to form small particles. These particles contribute to particulate matter (PM) pollution. Small particles may penetrate deeply into the lungs and in sufficient quantity can contribute to health problems.

Learn more about particulate matter

### What are the environmental effects of $SO_2$ and other sulfur oxides?

At high concentrations, gaseous SOx can harm trees and plants by damaging foliage and decreasing growth.

$SO_2$ and other sulfur oxides can contribute to acid rain which can harm sensitive ecosystems.

Learn more about acid rain

### Visibility

$SO_2$ and other sulfur oxides can react with other compounds in the atmosphere to form fine particles that reduce visibility (haze) in parts of the United States, including many of our treasured national parks and wilderness areas.

Learn more about visibility and regional haze

Deposition of particles can also stain and damage stone and other materials, including culturally important objects such as statues and monuments.

## What is being done to reduce $SO_2$ pollution?

EPA's national and regional rules to reduce emissions of $SO_2$ and pollutants that form sulfur oxides ($SO_x$) will help state and local governments meet the Agency's national air quality standards.

> Learn about how air quality standards help reduce $SO_2$

EPA identifies areas where the air quality does not meet EPA $SO_2$ standards. For these areas, state, local, and tribal governments develop plans to reduce the amount of $SO_2$ in the air.

> Learn more about $SO_2$ air quality designations and state implementation plans (SIPs)

BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

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Exhibit to
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Exhibit 2-69:
EPA PM Information

# Health and Environmental Effects of Particulate Matter (PM)

www.epa.gov/pm-pollution/health-and-environmental-effects-particulate-matter-pm

April 26, 2016




## Health Effects

The size of particles is directly linked to their potential for causing health problems. Small particles less than 10 micrometers in diameter pose the greatest problems, because they can get deep into your lungs, and some may even get into your bloodstream.

Exposure to such particles can affect both your lungs and your heart. Numerous scientific studies have linked particle pollution exposure to a variety of problems, including:

- premature death in people with heart or lung disease
- nonfatal heart attacks
- irregular heartbeat
- aggravated asthma
- decreased lung function
- increased respiratory symptoms, such as irritation of the airways, coughing or difficulty breathing.

People with heart or lung diseases, children, older adults, minority populations, and low socioeconomic status populations are the most likely to be affected by particle pollution exposure, either because they are more sensitive or may have higher exposures.

AirNow can help you monitor air quality near you, and protect yourself and your family from elevated PM levels.

## Environmental Effects

### Visibility impairment

Fine particles ($PM_{2.5}$) are the main cause of reduced visibility (haze) in parts of the United States, including many of our treasured national parks and wilderness areas. Learn more about visibility and haze

### Environmental damage

Particles can be carried over long distances by wind and then settle on ground or water. Depending on their chemical composition, the effects of this settling may include:

- making lakes and streams acidic
- changing the nutrient balance in coastal waters and large river basins
- depleting the nutrients in soil
- damaging sensitive forests and farm crops
- affecting the diversity of ecosystems
- contributing to acid rain effects.

### Materials damage

PM can stain and damage stone and other materials, including culturally important objects such as statues and monuments. Some of these effects are related to acid rain effects on materials.

## Further Reading

Particle Pollution and Your Health (txt) (2 pp, 320 KB): Learn who is at risk from exposure to particle pollution, what health effects you may experience as a result of particle exposure, and simple measures you can take to reduce your risk.

How Smoke From Fires Can Affect Your Health: It is important to limit your exposure to smoke -- especially if you may be susceptible.

EPA research on airborne particulate matter: EPA supports research that provides the critical science on PM and other air pollutants to develop and implement Clean Air Act regulations that protect the quality of the air we breathe.