

BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c))
Emergency Order: Transalta)
Centralia Generation LLC)
_____)

Order No. 202-25-11

Motion to Intervene, Motion for Clarification, and Requests for Rehearing and Stay
of Sierra Club, NW Energy Coalition, Washington Conservation Action, Climate
Solutions, Public Citizen, and Environmental Defense Fund
(collectively, “Public Interest Organizations” or “PIOs”)

Exhibit 1-91:
NERC Winter Assessments 2022-24 (Compiled)



NORTH AMERICAN ELECTRIC
RELIABILITY CORPORATION

2022–2023 Winter Reliability Assessment

November 2022



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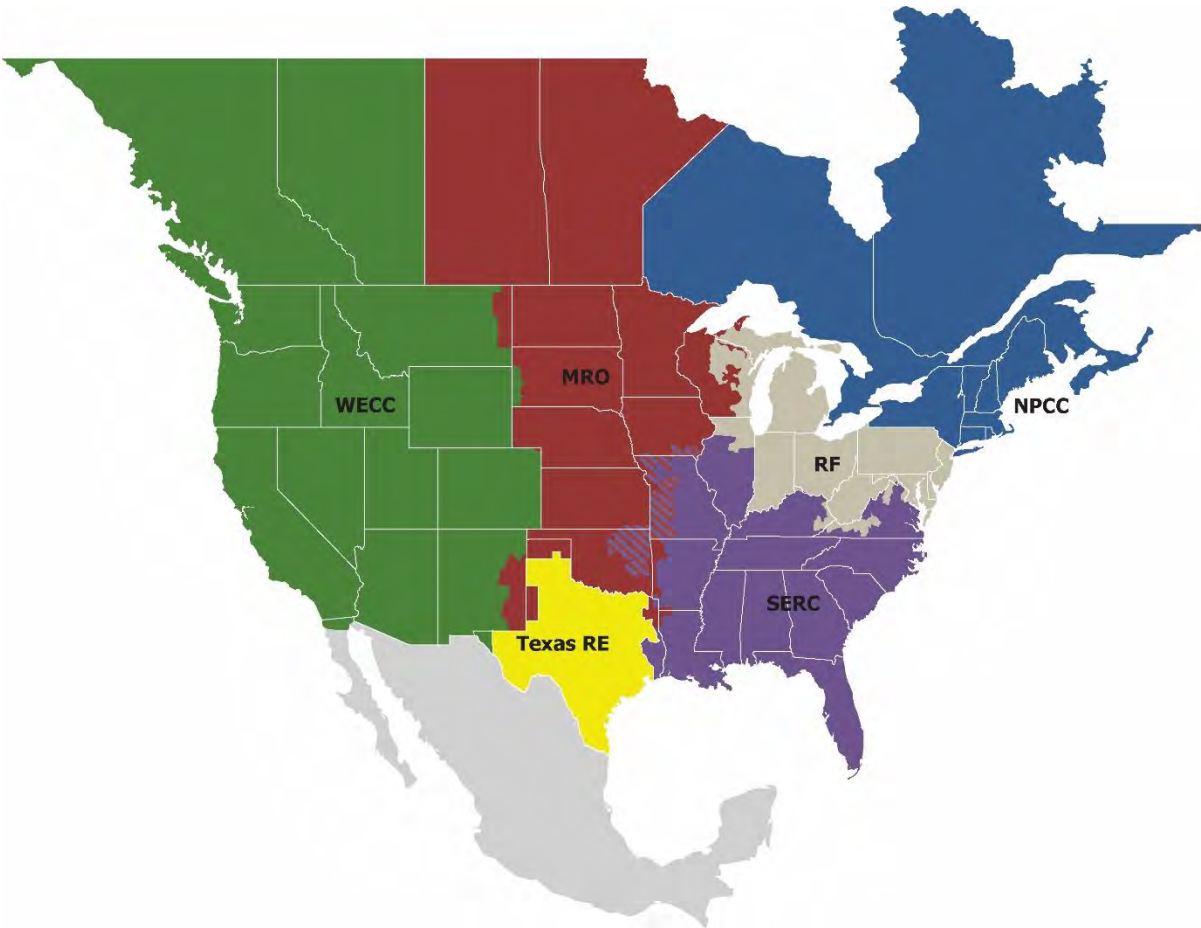
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Preface

The vision for the Electric Reliability Organization Enterprise, which is comprised of the North American Electric Reliability Corporation (NERC) and the six Regional Entities, 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

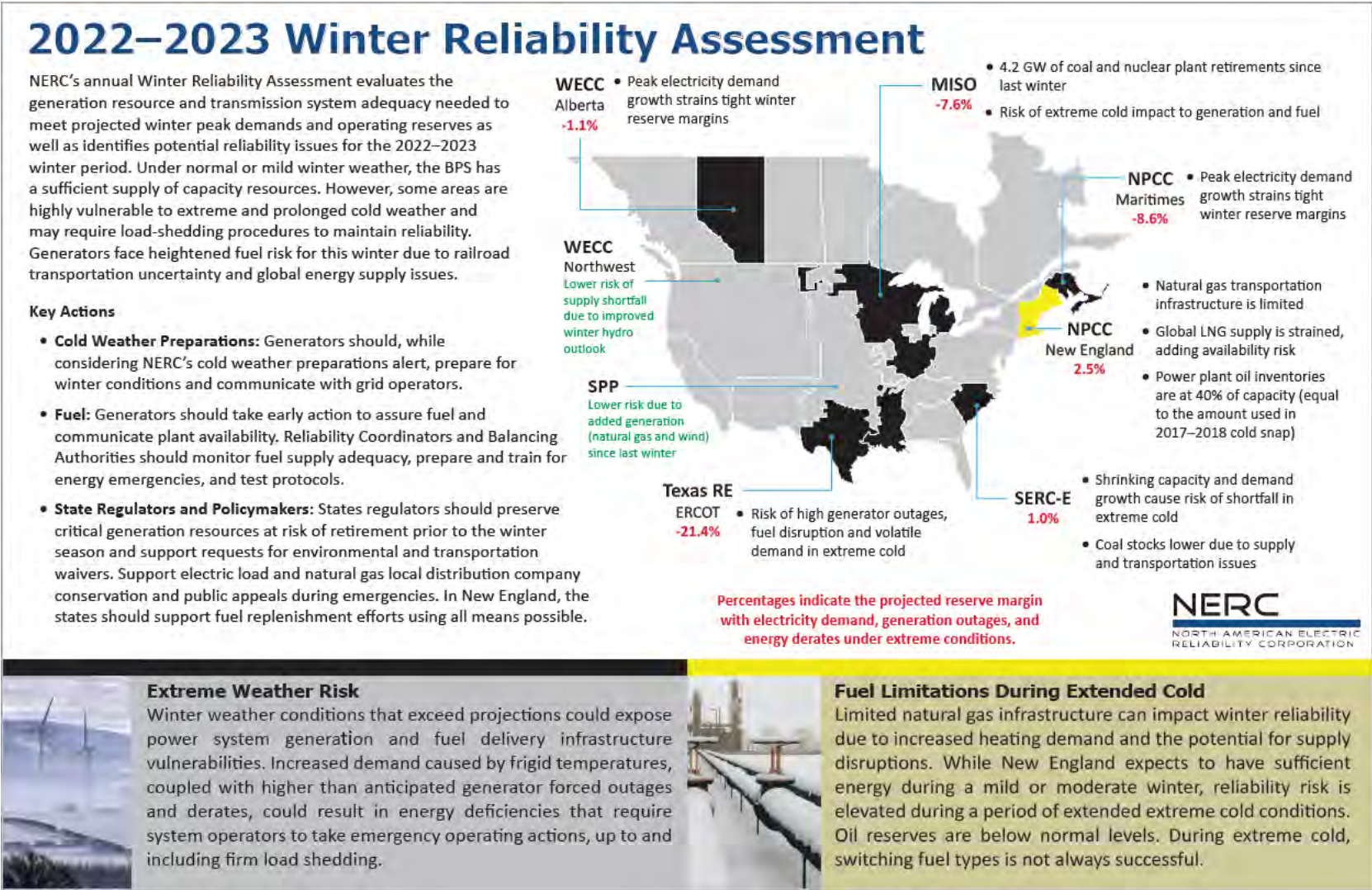
The North American BPS is made up of six Regional Entity boundaries as shown in the map below. The multicolored area denotes overlap as some load-serving entities participate in one Regional Entity while associated Transmission Owners/Operators participate in another. Refer to the [Data Concepts and Assumptions](#) section for more information. A map and list of the assessment areas can be found in the [Regional Assessments Dashboards](#) section.



MRO	Midwest Reliability Organization
NPCC	Northeast Power Coordinating Council
RF	ReliabilityFirst
SERC	SERC Reliability Corporation
Texas RE	Texas Reliability Entity
WECC	WECC

About this Assessment

NERC’s 2022–2023 Winter Reliability Assessment (WRA) identifies, assesses, and reports on areas of concern regarding the reliability of the North American BPS for the upcoming winter season. In addition, the WRA presents peak electricity demand and supply changes and highlights any unique regional challenges or expected conditions that might impact the BPS. The reliability assessment process is a coordinated reliability evaluation between the Reliability Assessment Subcommittee (RAS), the Regional Entities, and NERC staff with demand and resource projections obtained from the assessment areas. This report reflects NERC’s independent assessment and is intended to inform industry leaders, planners, operators, policy makers, and regulatory bodies so that they are better prepared to take necessary actions to ensure BPS reliability. This report also provides an opportunity for the industry to discuss plans and preparations to ensure reliability for the upcoming winter period. Below is a summary of this WRA.



Key Findings

This *WRA* covers the upcoming three-month (December–February) winter period. This assessment provides an evaluation of generation resource and transmission system adequacy necessary to meet projected winter peak demands and operating reserves. This assessment identifies potential reliability issues of interest and regional topics of concern. The following findings are NERC and the Regional Entities’ (the ERO Enterprise’s) independent evaluation of electricity generation and transmission capacity and potential operational concerns that may need to be addressed for the upcoming winter:

A large portion of the North American BPS is at risk of insufficient electricity supplies during peak winter conditions (Figure 1). Higher peak-demand projections, inadequate generator weatherization, fuel supply risks, and natural gas infrastructure are contributing to risks seen in the following areas:

- **Texas RE-ERCOT:** The risk of a significant number of generator forced outages in extreme and prolonged cold temperatures continues to threaten reliability where generators and fuel supply infrastructure are not designed or retrofitted for such conditions. Furthermore, a U.S. Environmental Protection Agency (EPA) decision regarding compliance with hazardous coal ash disposal regulations is expected before the end of 2022 that could impact the availability of two coal-fired generation units (combined total of 1,477 MW) in the last weeks of winter. These units could be important resources during extreme conditions, and an EPA decision can provide flexibility in scheduling outages for plant improvements. Demand volatility in Texas from extreme cold temperatures also contributes to energy shortfall risks.
- **Midcontinent ISO (MISO):** Since the 2021/2022 winter, reserve margins in MISO have fallen by over 5%. Nuclear and coal-fired generation retirements total over 4.2 GW since the prior winter. Declining reserves are the result of few resource additions. An extreme cold-weather event that extends deep into MISO’s area could lead to high generator outages from inadequate weatherization in southern units and unavailability of fuel for natural-gas-fired generators.
- **SERC-East:** Like Texas RE-ERCOT and the southern parts of MISO, extreme cold could result in high generator outages and demand volatility. A rare cold weather event in the South could result in an energy emergency in this area.
- **WECC-Alberta and NPCC-Maritimes:** Peak electricity demand is projected to grow in both of these winter-peaking systems. In Maritimes, this could strain capacity for normal winter peak conditions. Alberta has sufficient capacity for normal winter peak demand; however, extreme conditions that cause high generator forced outages are likely to cause energy emergencies.

- **NPCC-New England:** The capacity of the natural gas transportation infrastructure could be constrained when cold temperatures cause peak demand for both electricity generation and consumer space-heating needs. Potential constraints on the fuel delivery systems and limited inventory of liquid fuels may exacerbate the risks for fuel-based generator outages and output reductions that result in energy emergencies during extreme weather.

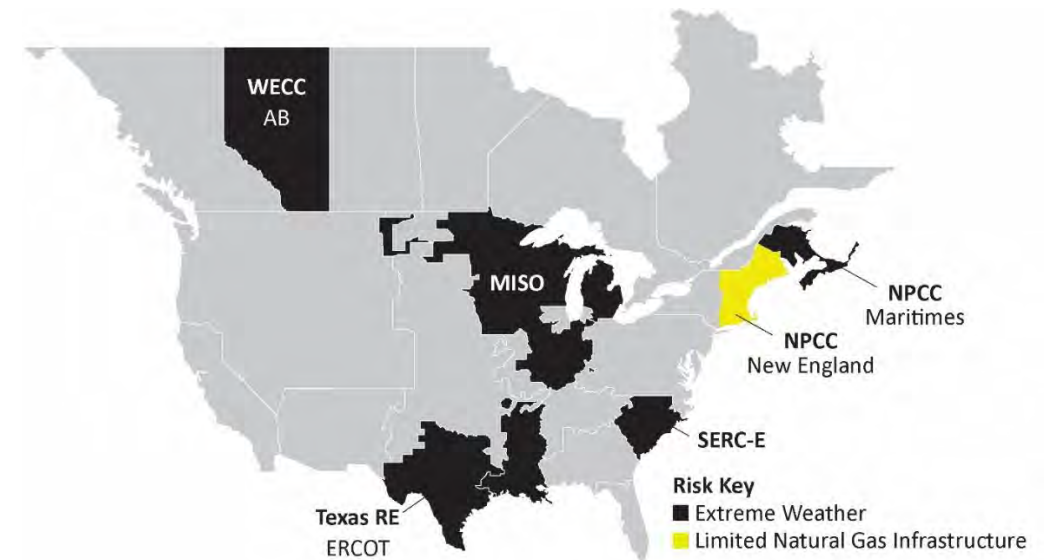


Figure 1: Winter Reliability Risk Area Summary

- **Generator Owners (GO) face additional fuel and supply risk.** Reliable operation of the thermal generating fleet is critical to winter reliability, and assured fuel supplies is an ongoing winter reliability concern. Current domestic and global affairs warrant even greater attention to generator fuel supplies, including natural gas, fuel oil, and coal for the upcoming winter. Inventories of coal and fuel oil in most areas are lower than usual due to a summer of high electricity demand and high natural gas prices that made other fuels more economically advantageous for electricity generation. Low fuel storage levels coupled with a range of potential fuel resupply challenges are creating additional risks for winter regional BPS reliability. Careful attention should be paid to periodic fuel surveys that provide early indication of fuel supply risks.

- **Steps have been taken since 2021’s Winter Storm Uri to improve generator performance during extreme cold weather events.** The three areas hardest hit by the 2021 Winter Storm Uri¹—Texas RE-ERCOT, SPP, and MISO—have implemented several improvements based on their operating experience. Texas weatherization standards for both generators and natural gas facilities designated as critical infrastructure aim to improve generator availability during extreme weather this winter. In SPP and MISO, where Winter Storm Uri impacts were less severe, a focus on operational coordination and situational awareness is intended to help operators ensure that sufficient resources are available for extreme conditions. While the risk of energy emergencies for the upcoming winter has not been eliminated, improvements—due to lessons learned from Winter Storm Uri—are expected to reduce the likelihood and lessen the severity of a future Winter Storm Uri scale event.
- **NERC’s 2022 Level 2 Alert, *Cold Weather Preparations for Extreme Weather Events*.** In September 2022, the ERO issued a Level 2 NERC alert to Reliability Coordinators (RC), Balancing Authorities (BA), Transmission Operators (TOP), and GOs.² The alert includes recommendations as well as a series of questions to help evaluate the Bulk Electric System’s winter readiness. The responses indicate the importance of grid operators being prepared to implement their operating plans to manage potential supply shortfalls in extreme weather.
- **Inadequate supply of distribution transformers could slow restoration efforts following winter storms.** The electricity industry is facing a shortage of distribution transformers as a result of production not keeping pace with demand. A survey by the American Public Power Association revealed that many utilities have low levels of emergency stocks that are used for responding to natural disasters and catastrophic events.³ Severe winter storms often include high winds, icing, and precipitation that damage distribution power lines and transformers. Asset sharing programs used by utilities provide visibility and voluntary equipment sharing to maximize resources; however, electricity customers may experience delayed restoration of power following storms as crews must work to obtain new equipment.

Recommendations

To reduce the risks of energy shortfalls on the BPS this winter, NERC recommends the following:

- BAs and RCs should work with GOs to ensure fuel supplies are adequate for normal and extreme conditions prior to winter. Fill storage capacity, prepare fuel delivery systems, and coordinate with fuel providers to secure needed fuel as applicable. While short-term solutions are limited, firm supply arrangements should be pursued when feasible. Long-term solutions are needed to secure energy and maintain fuel assurance to support reliability and resilience. In addition, GOs should routinely and periodically keep BAs and RCs informed on fuel levels and readiness.
- RCs and BAs should implement fuel surveys early to monitor the adequacy of fuel supplies. They should prepare their operating plans to manage potential supply shortfalls and take proactive steps for generator readiness, fuel availability, load curtailment, and sustained operations in extreme conditions.
- State and province policy makers have the authority and jurisdiction to implement actions that preserve critical generation resources. State and provincial regulators should consider energy risks for the upcoming winter season and take steps to delay imminent generation retirements if essential to reliability. Additionally, state regulators can assist grid operators in advance of and during extreme cold weather by supporting requested environmental and transportation waivers as well as public appeals for electric load and natural gas conservation.
- Grid operators, GOs, and Generator Operators (GOP) should implement the mitigations identified in the NERC Level 2 alert, *Cold Weather Preparations for Extreme Weather Events—II*, and they should take recommended weatherization steps prior to winter.

¹ [The February 2021 Cold Weather Outages in Texas and the South Central United States | FERC, NERC and Regional Entity Staff Report | Federal Energy Regulatory Commission](#)

² <https://www.nerc.com/pa/rrm/bpsa/Alerts%20DL/NERC%20Alert%20R-2022-09-12-01%20Cold%20Weather%20Events%20II.pdf>

³ <https://www.publicpower.org/periodical/article/appa-survey-members-shows-distribution-transformer-production-not-meeting-demand>

Risk Highlights

Additional Generator Fuel and Supply Risk

Reliable operation of the thermal generating fleet is critical to winter operations, and assured fuel supplies is an ongoing winter reliability concern. The current state of domestic and global affairs warrants even greater attention on generator fuel supplies, including natural gas, fuel oil, and coal. Low fuel storage levels coupled with a range of potential fuel resupply challenges are creating additional risks for winter regional BPS reliability.

Generator Fuel Supplies

Owners of coal, fuel oil, and dual-fueled generators in North America typically replenish stored fuels following the peak summer season in preparation for winter. Energy suppliers also increase inventories of natural gas, coal, and distillate fuels in preparation for high-demand winter periods. Several fuel supply challenges have emerged in the lead-up to the 2022–2023 winter that are being monitored by grid operators and GOs, including potential rail strikes, constrained and delayed rail deliveries, reduced stored natural gas and fuel oil inventories, and uncertainty from global markets in New England potentially impacting liquefied natural gas (LNG) deliveries. The following are two areas of concern:

Coal Inventories

Grid operators in the U.S. Southeast, MISO, and PJM are monitoring coal inventories (fuel and consumables) as GOs face limited stocks and resupply uncertainty. Across the United States, resupply by rail has been hampered throughout 2022 as staffing shortages and other issues have affected the rail industry. Some GOs in the Midwest and Southeast are experiencing delivery issues for coal and certain emissions-control chemicals. A small number of units currently have low coal inventory. Inventories in some areas are lower than typical following a summer of high electricity demand and high natural gas prices that made coal more economically advantageous. A milder fall in the Central and Eastern parts of North America has helped some coal stocks rebound. Monitoring performed by PJM, where coal-fired generation can be expected to contribute over 25% of peak demand needs, indicates that pre-winter coal supplies in November now exceed 85% of the levels reached at their peak in the prior winter ([Figure 2](#)).

Based on coal stock data from the Energy Information Administration,⁴ fuel inventories have reached 96 days of bituminous supply and 81 days subbituminous across the coal generation fleet on average ([Figure 3](#)). Some plants reported as low as 15 days of supply during the past summer.

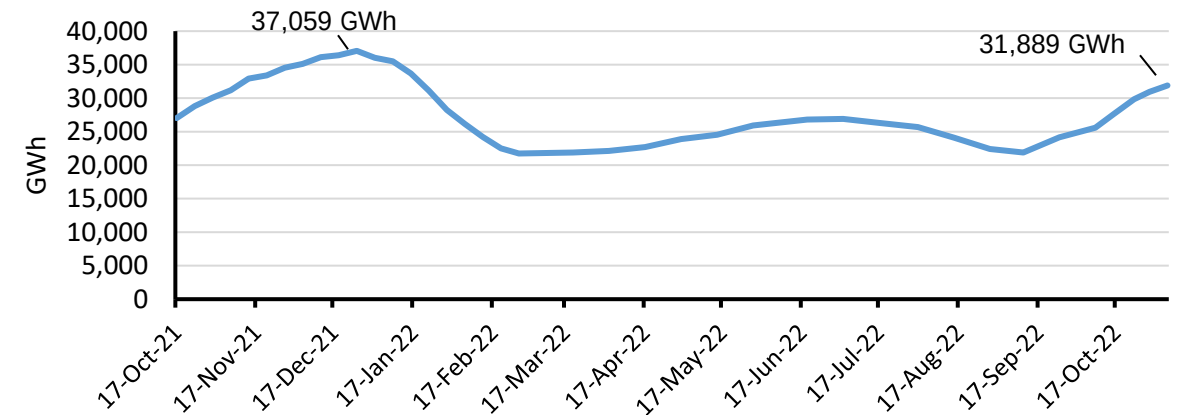


Figure 2: PJM Bi-weekly Fuel Inventory for October 10, 2022⁵

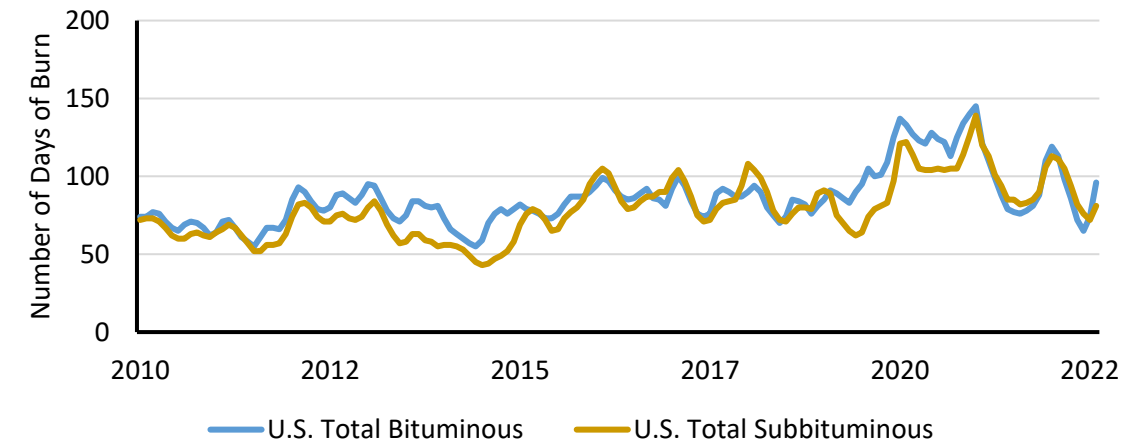


Figure 3: Days of Burn by Non-lignite Coal, January 2010–August 2022

⁴ EIA Electric Power Sector Coal Stocks: [Electricity Monthly Update - U.S. Energy Information Administration \(EIA\)](#)

⁵ Displays the fuel inventory in GWh calculated by PJM based on data provided through PJM's Fuel Inventory and Supply Data Request. Information is available on PJM's Operating Committee page: <https://www.pjm.com/committees-and-groups/committees/oc>

Shipping availability by rail this winter is uncertain, reinforcing the need to monitor generator coal stockpiles and act early to reach peak winter levels. RCs in affected areas are continuing to mitigate the coal supply issues by working with their BAs to limit run time of low-inventory plants, using economics, de-rating units, reducing loading at night, and monitoring coal supply.

LNG and Fuel Oil Availability

Low fuel availability elevates winter reliability risk. LNG is critical to meeting energy needs in New England during cold weather, and the continuing disturbance to global energy markets creates supply uncertainty. LNG terminals in New England help alleviate pipeline constraints by providing access points for LNG shipped in tankers to be vaporized and injected into pipelines that serve many natural-gas-fired generators.

As a global energy commodity, LNG is experiencing record high demand that is straining supplies and transportation as well as increasing the risk of disruption. Fuel oil stores are also an important generator fuel in New England as well as in neighboring New York and the Maritimes Provinces of Canada.

Fuel oil is used as either a primary fuel or as a backup to natural gas. Replenishment of on-site generator fuel oil stores since last winter is lagging, and levels remain below historical norms. In New England, the Independent System Operator (ISO) survey of generators in October indicates that on-site stored fuel oil used for electricity generation is just over 92 million gallons, or 40% of available storage capacity (Figure 4). Most oil-fired generating capacity (70%) in New England uses lighter distillate fuel oil (DFO). The remaining 30% of the oil-fired fleet capacity uses residual fuel oil (RFO). The current level of combined fuel oil in storage is far lower than the 54% peak level of the prior winter. It is also close to being insufficient for the kind of extreme winter events that could occur in the area. For instance, during a 13-day cold snap over the 2017–2018 winter, over 80 million gallons of fuel oil was used for electricity generation in the New England area.⁶

⁶ ISO-NE Winter 2017/2018 Recap: Historic cold snap reinforces findings in Operational Fuel-Security Analysis: <https://isonewswire.com/2018/04/25/winter-2017-2018-recap-historic-cold-snap-reinforces-findings-in-operational-fuel-security-analysis/>

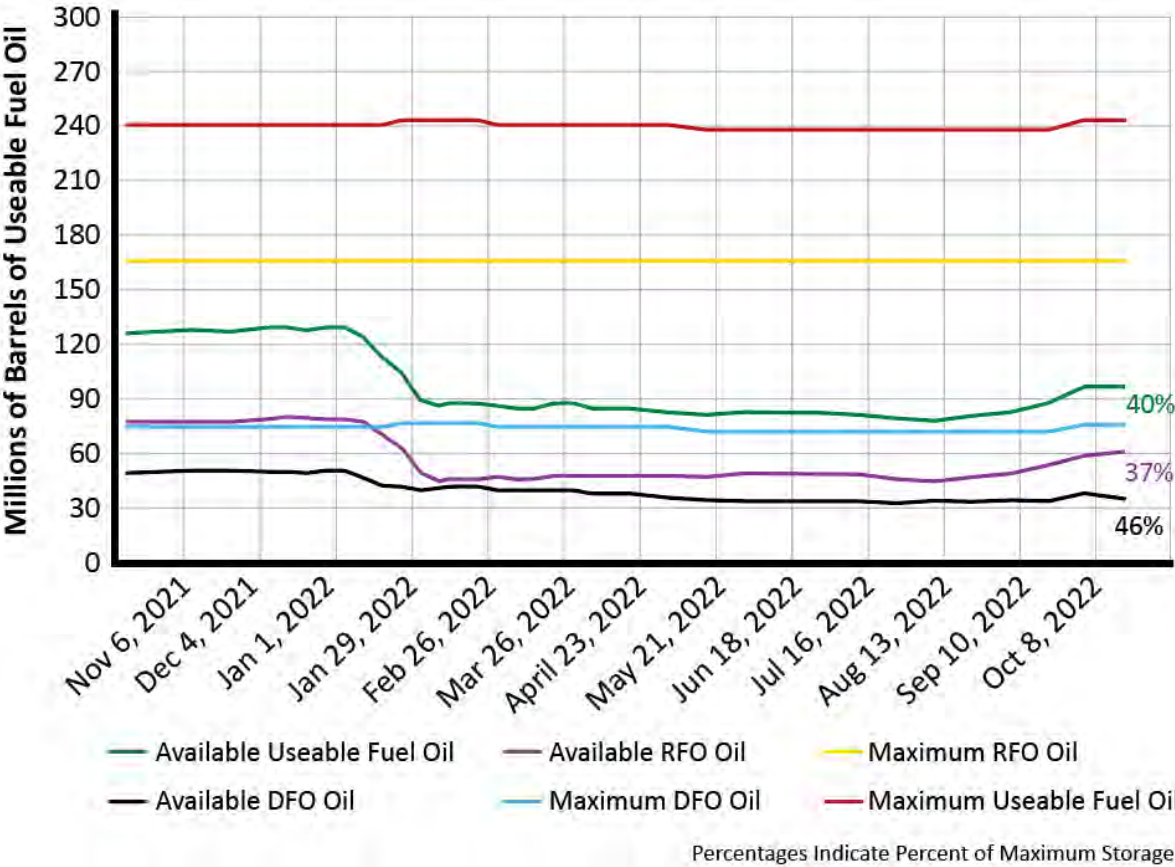


Figure 4: ISO New England 21-day Energy Assessment, Total Usable New England Fuel Oil Inventory Through October 8, 2022⁷

Assessment of Stored Fuel Risk

No specific issues have been identified that would prevent reaching the necessary fuel levels. However, weather, staffing, and general issues affecting transportation have the potential to either directly impact fuel delivery to generator storage sites or affect fuel production through disrupted chemical shipments. Careful attention to ISO’s pre-winter and periodic fuel surveys is needed to provide early indication of fuel supply risks. Tools like ISO-New England’s (ISO-NE) 21-day energy assessments can reduce these risks to operations.

⁷ <https://www.iso-ne.com/isoexpress/web/reports/operations/-/tree/21-Day-Energy-Assessment-Forecast-and-Report-Results>

Seasonal Risk Scenario Margins

Seasonal risk scenarios for each assessment area are presented in the [Regional Assessments Dashboards](#) section. The on-peak reserve margins and seasonal risk scenario chart in each dashboard provide potential winter peak demand and resource condition information. The reserve margins on the right side of the dashboard pages provide a comparison to the previous year’s assessment. The seasonal risk scenario charts present deterministic scenarios for further analysis of different demand and resource levels with adjustments for normal and extreme conditions. The assessment areas determined the adjustments to capacity and peak demand based on methods or assumptions that are summarized below the seasonal risk scenario charts; see the [Data Concepts and Assumptions](#) for more information about these chart.

The seasonal risk scenario charts can be expressed in terms of reserve margins. In [Table 1](#), each assessment area’s Anticipated Reserve Margins are shown alongside the reserve margins for a typical generation outage scenario (where applicable) and the extreme demand and resource conditions in their seasonal risk scenario. The typical outages reserve margin is comprised of anticipated resources, less the capacity that is likely to be in maintenance or forced outage at peak demand. If the typical maintenance or forced outage margin is the same as the anticipated reserve margin, it is because an assessment area has already factored typical outages into the anticipated resources. The extreme conditions margin includes all components of the scenario and represents the most severe operating conditions of an area’s scenario. Note that any reserve margin below zero indicates that the resources fall below demand in the scenario.

Table 1: Seasonal Risk Scenario Margins			
Assessment Area	Anticipated Reserve Margin	Typical Outages	Extreme Conditions
MISO	43.1%	14.0%	-7.6%
MRO-Manitoba	18.1%	16.2%	9.2%
MRO-SaskPower	28.7%	22.0%	12.6%
NPCC-Maritimes	17.5%	11.3%	-8.6%
NPCC-New England	72.0%	54.7%	2.5%
NPCC-New York	83.2%	58.9%	23.9%
NPCC-Ontario	24.3%	24.3%	9.5%
NPCC-Quebec	12.7%	12.7%	2.3%
PJM	45.9%	33.2%	16.0%
SERC-C	25.1%	18.4%	2.7%
SERC-E	23.9%	17.3%	1.0%
SERC-FP	36.7%	33.2%	0.0%
SERC-SE	31.7%	22.8%	8.4%
SPP	70.0%	44.5%	9.3%
TRE-ERCOT	36.4%	20.4%	-21.4%
WECC-AB	20.8%	18.3%	-1.1%
WECC-BC	16.2%	16.1%	6.4%
WECC-CAMX	49.7%	41.7%	18.6%
WECC-WPP	33.8%	31.3%	10.1%
WECC-SRSG	93.5%	84.7%	55.7%

Reliability Enhancements in Storm-Affected Assessment Areas

Industry, regulators, and the ERO Enterprise have taken significant actions to improve winter readiness following the devastating effects of the February 2021 Winter Storm Uri cold weather event. The first cold weather Reliability Standards, adopted by the NERC Board in June 2021, advance BPS reliability by requiring generators to implement plans for cold weather preparedness as well as to provide cold weather operating parameters to their RCs, TOPs, and BAs for use in operating plans. Though these requirements take effect in the United States in April 2023, just after the upcoming winter season, some reliability benefits of the new requirements may be realized sooner through cold weather planning and preparations that improve generator performance and operator coordination. Across industry, the recommendations of the FERC-NERC-Regional Entity staff report—*The February 2021 Cold Weather Outages in Texas and South Central United States*—are shaping direction at ISO/RTOs, in technical committees and industry forums, and among industry planners and operators.

The three hardest-hit areas by the 2021 Winter Storm Uri—Texas RE-ERCOT, SPP, and MISO—have implemented several improvements based on their operating experience. Texas weatherization standards, applicable to generators and natural gas facilities designated as critical infrastructure, aim to improve generator availability during extreme weather this winter. In SPP and MISO, where Winter Storm Uri impacts were less severe, a focus on operational coordination and situational awareness should help operators prepare to have sufficient resources for extreme conditions.

Texas RE-ERCOT, SPP, and MISO continue to be at-risk for energy emergencies during the upcoming winter based on their expected resources, normal and extreme demand, and historical generator outage information. However, the enhancements described in the following Texas RE-ERCOT, SPP, and MISO sub-sections are expected to reduce the likelihood of emergencies and lessen the severity that an extreme winter cold weather event on the scale of Winter Storm Uri could cause.

Texas RE-ERCOT

Since February 2021, Texas regulators, ERCOT, and GOs have implemented winter preparedness programs and other reforms aimed at improving generator performance in extreme winter weather. These actions are expected to reduce generator outages in extreme conditions to reduce the likelihood of energy emergencies as well as to mitigate impacts to firm load should an energy emergency occur:

- Regulations in Texas require generator and transmission owners to winterize equipment and facilities. ERCOT conducts weather preparedness inspections of generation and transmission as well as tracks exceptions to requirements until completed.
- In August 2022 the Railroad Commission of Texas (RRC), which regulates the Texas fuel oil and natural gas industry, approved its Final Rule⁸ on weather emergency preparedness standards for designated “critical [natural] gas facilities” in the state’s new Electricity Supply Chain Map.⁹ TRRC inspectors will begin inspecting facilities to determine compliance beginning December 1, 2022, based on submitted compliance attestations. Inspections will focus on infrastructure that produces, stores, processes, and/or transports large volumes of natural gas, and this TRRC effort will be prioritized by facility size.
- ERCOT procured over 2,900 MW of firm fuel supply resources for the upcoming winter. Under the new market product, the procured natural-gas-fired generators must have back-up fuel that would support operations for 48 hours in the event that natural gas supply is interrupted.
- ERCOT has reviewed load-shedding plans with area TOPs and conducts periodic training exercises. Additionally, they coordinate with TOPs to prepare enhanced manual load-shedding and rotating outage plans designed to minimize disruption to firm load.

SPP

SPP is implementing a set of actions—policy changes and assessments approved by the SPP Board of Directors—to address issues related to fuel assurance, resource planning and availability, emergency response, communications, and other critical areas. For the upcoming winter, these actions will improve generator preparedness and operator response:

- SPP held the Winter Preparedness Workshop to help inform members of forecasted conditions for the upcoming season and review SPP’s seasonal preparedness steps outlined in its operating procedures.
- RC and BA staff have implemented a high risk scenario alerting system for managing risk periods. This system will identify and alert staff on potential upcoming records, such as load, wind, and wind penetration, to allow time for extra studies to be executed and analyzed as well as to be addressed by the SPP response team.

SPP established an Improved Resource Availability Task Force, which will take primary responsibility for addressing recommendations related to fuel assurance and resource planning as well as

⁸ <https://www.rrc.texas.gov/media/c5hdc4ga/rule-3-66.pdf>

⁹ https://www.puc.texas.gov/agency/resources/reports/mapping/2021_Mapping_Agency_Report.pdf

availability that is identified in SPP's *Comprehensive Review of SPP's Response to the February 2021 Winter Storm* report.¹⁰

MISO

MISO has implemented actions to provide situational awareness and early coordination for reducing risks from extreme winter weather:

- MISO continues to survey GOs and GOPs about unit preparedness and winter fuel sufficiency.
- Processes are in place for coordination with neighboring RCs and BAs on needs for firm or non-firm transfers to address extreme system conditions. Pre-season transfer studies for normal and extreme scenarios are underway.

For future years, MISO's new resource adequacy construct (filed with FERC for approval) is expected to deliver additional winter resource capacity by using a winter reserve margin and resource capacity accreditations that account for winter peak conditions.

MISO Neighboring Area Studies

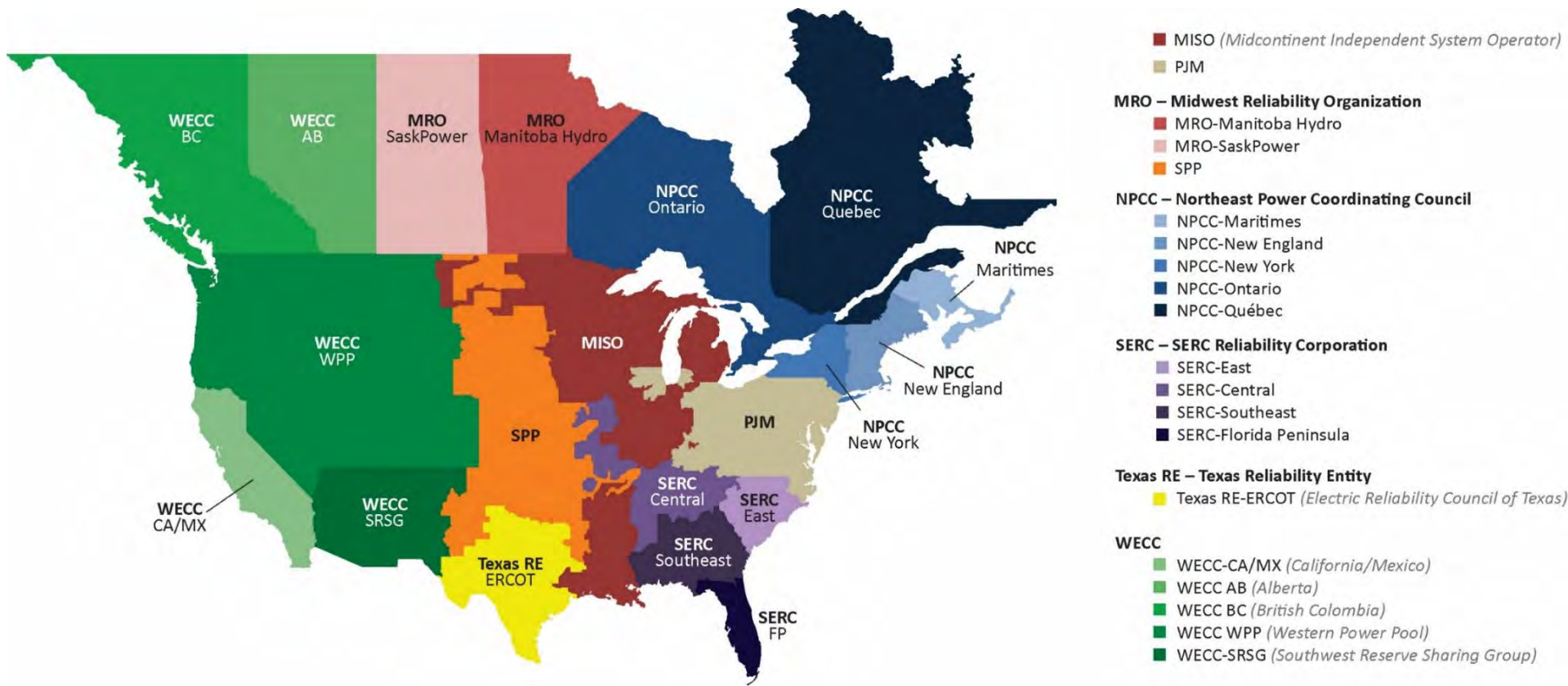
During Winter Storm URI, other areas in the Eastern Interconnection experienced localized transmission emergencies resulting from the large transfers flowing across the transmission system from generators in PJM to the affected areas in MISO and SPP. Accordingly, the *FERC-NERC-Regional Entity staff Joint Report* recommended planners and operators study large power transfers during stressed conditions. Transfer studies have been conducted in SERC to help prepare for the upcoming winter. During extreme cold temperatures, there is the potential for significant transfers through the area as excess power is shipped to meet power demands in affected areas outside of SERC.

A SERC technical working group performed a 2022–2023 winter reliability study to determine the adequacy and reliability of the SERC transmission system using a 2022–2023 winter peak power flow model, which included 12 GW power transfer from PJM to MISO. The study also simulated the impacts of higher load demands due to colder than normal temperatures in each SERC sub-area by increasing generation throughout them all while simultaneously increasing load in a particular sub-area. SERC concluded that the transmission system was adequate for normal and extreme conditions and that localized transmission constraints, when observed, could be mitigated through system reconfiguration.

¹⁰ <https://www.spp.org/markets-operations/current-grid-conditions/2021-winter-storm-review/>

Regional Assessments Dashboards

The following assessment area dashboards and summaries were developed based on data and narrative information collected by NERC from the six Regional Entities on an assessment area basis. Guidelines and definitions are in the [Data Concepts and Assumptions](#) table. On-Peak Reserve Margin bar charts show the Anticipated Reserve Margin compared to a Reference Margin Level established for the area to meet resource adequacy criteria. Prospective Reserve Margins can give an indication of additional on-peak capacity but are not used for assessing adequacy. The operational risk analysis shown in the following regional assessments dashboard pages provides a deterministic scenario for understanding how various factors that affect resources and demand can combine to impact overall resource adequacy. For each assessment area, there is a risk-period scenario graphic; the left blue column shows anticipated resources (from the [Demand and Resource Tables](#)), and the two orange columns at the right show the two demand scenarios of the normal peak net internal demand (from the [Demand and Resource Tables](#)) and the extreme winter peak demand determined by the assessment area. The middle red or green bars show adjustments that are applied cumulatively to the anticipated resources. Adjustments may include reductions for typical generation outages (maintenance and forced not already accounted for in anticipated resources) and additions that represent the quantified capacity from operational tools (if any) that are available during scarcity conditions but have not been accounted for in the WRA reserve margins. Resources throughout the scenario are compared against expected operating reserve requirements that are based on peak load and normal weather. The cumulative effects from extreme events are also factored in through additional resource derates or low-output scenarios.

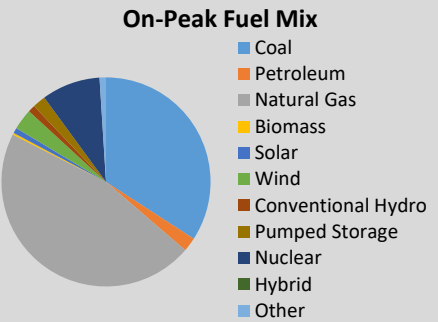




MISO

The Midcontinent Independent System Operator, Inc. (MISO) is a not-for-profit, member-based organization that administers wholesale electricity markets that provide customers with valued service; reliable, cost-effective systems and operations; dependable and transparent prices; open access to markets; and planning for long-term efficiency.

MISO manages energy, reliability, and operating reserve markets that consist of 36 local Balancing Authority and 394 market participants, serving approximately 42 million customers. Although parts of MISO fall in three Regional Entities, MRO is responsible for coordinating data and information submitted for NERC’s reliability assessments.



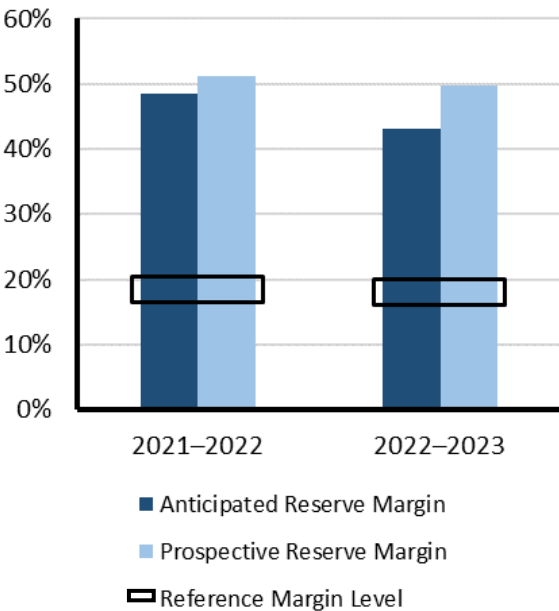
Highlights

- Since 2021–2022 winter, reserve margins in MISO have fallen by over 5%. Nuclear and coal-fired generation retirements total over 4.2 GW since the prior winter. Declining reserves are the result of few resource additions. Since last winter, more demand response (2,250 MW) and new wind generation (500 MW on-peak/3,200 MW nameplate) was added.
- MISO continues to survey and coordinate with its members on winter preparedness and fuel sufficiency. In addition, MISO is acknowledging that resource adequacy risk is not limited to the summer system peak season, MISO is filing changes to the resource adequacy construct to implement a seasonal resource adequacy construct and seasonal unit accreditation to better affirm adequate supply in all seasons.
- Though risk has been identified for this upcoming winter season in a high generation outage and high winter load scenario, MISO expects to maintain reliability through the use of measures that include load modifying resources (LMR) (MISO’s demand response), non-firm transfers into the system, energy only interconnection service resources not receiving capacity credit, and/or internal transfers that exceed the sub-area import/export constraint between the MISO North/Central and South areas. MISO continues to coordinate extensively with neighboring RCs and BAs to improve situational awareness and vet needs for firm or non-firm transfers to address extreme system conditions.

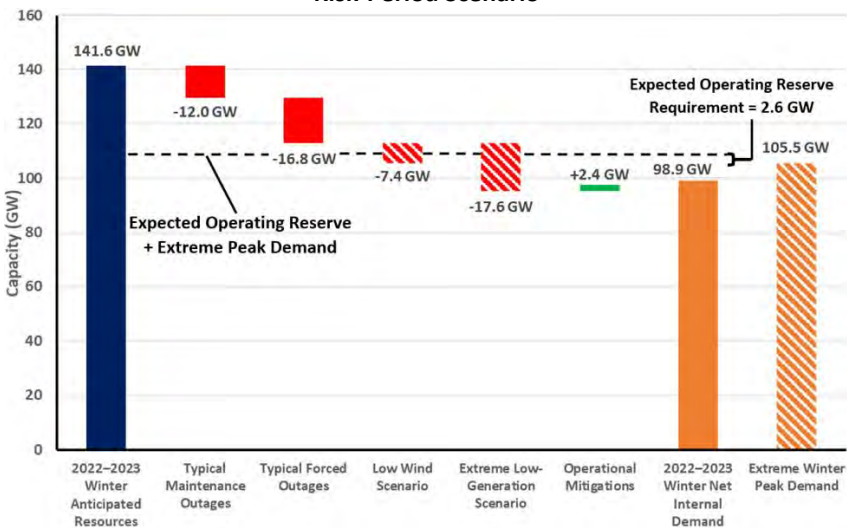
Risk Scenario Summary

Expected resources meet operating reserve requirements under normal peak-demand scenarios. Above-normal winter peak load and outage conditions could result in the need to employ operating mitigations (i.e., demand response and transfers) and energy emergency alerts (EEAs). Load shedding is unlikely but may be needed under wide-area cold weather events.

On-Peak Reserve Margins



Risk-Period Scenario



Scenario Description (See [Data Concepts and Assumptions](#))

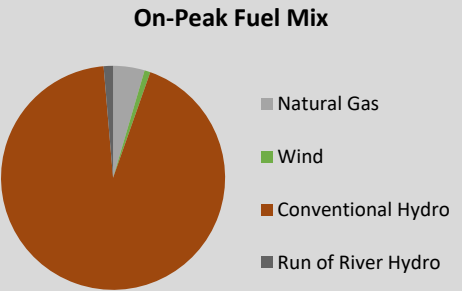
- Risk Period:** Highest risk for unserved energy at peak demand hour
- Demand Scenarios:** Net internal demand (50/50) and (90/10) demand forecast using 30 years of historical data
- Maintenance Outages:** Rolling five-year winter average of maintenance and planned outages
- Forced Outages:** Five-year average of all outages that were not planned
- Low Wind Scenario:** Below average wind contributions
- Extreme Low-Generation:** Maximum historical generation outages
- Operational Mitigations:** A total of 2.4 GW capacity resources available during extreme operating conditions



MRO-Manitoba Hydro

Manitoba Hydro is a provincial crown corporation and one of the largest integrated electricity and natural gas distribution utilities in Canada. Manitoba Hydro provides electricity to approximately 601,000 electric customers in Manitoba and provides approximately 291,000 customers with natural gas in Southern Manitoba. The service area is the province of Manitoba which is 251,000 square miles.

Manitoba Hydro is winter peaking. Manitoba Hydro is its own Planning Coordinator and Balancing Authority. Manitoba Hydro is a coordinating member of MISO. MISO is the Reliability Coordinator for Manitoba Hydro.



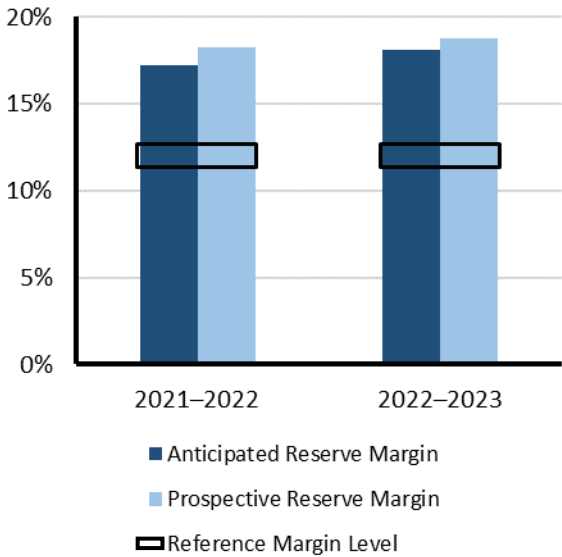
Highlights

- The Anticipated Reserve Margin for the 2022–2023 winter exceeds the 12% Reference Margin Level.
- There are no emerging reliability/resource adequacy issues anticipated for the upcoming winter season.
- All seven units at the Keeyask Hydroelectric Generating Station (630 MW net addition) are anticipated to be in commercial operation for the 2022–2023 winter.

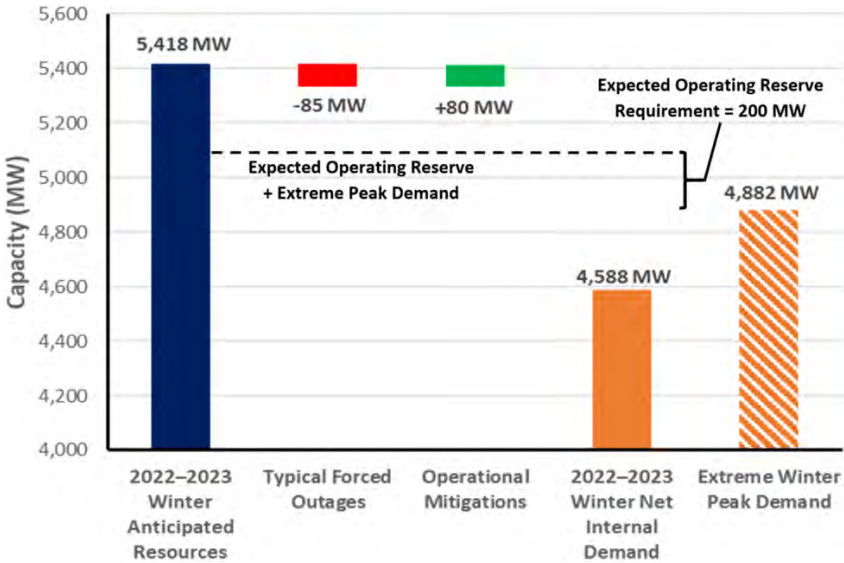
Risk Scenario Summary

Expected resources meet operating reserve requirements under the assessed scenarios.

On-Peak Reserve Margins



Risk-Period Scenario



Scenario Description (See [Data Concepts and Assumptions](#))

- Risk Period:** Highest risk for unserved energy at peak demand hour
- Demand Scenarios:** Net internal demand (50/50) and extreme demand scales additional load experienced during all-time peak actual versus forecasted load (January 2019)
- Forced Outages:** Accounts for average forced outages
- Operational Mitigations:** Recall 80 MW of additional curtailable load



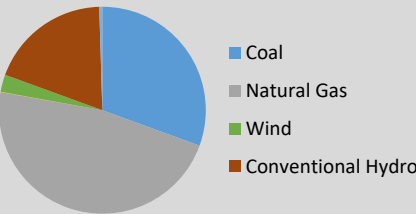
MRO-SaskPower

MRO-SaskPower is an assessment area in the Saskatchewan province of Canada. The province has a geographic area of 651,900 square kilometers (251,700 square miles) and approximately 1.1 million customers. Peak demand is experienced in the winter.

The Saskatchewan Power Corporation (SaskPower) is the Planning Coordinator and Reliability Coordinator for the province of Saskatchewan and is the principal supplier of electricity in the province.

SaskPower is a provincial crown corporation and, under provincial legislation, is responsible for the reliability oversight of the Saskatchewan Bulk Electric System and its interconnections.

On-Peak Fuel Mix



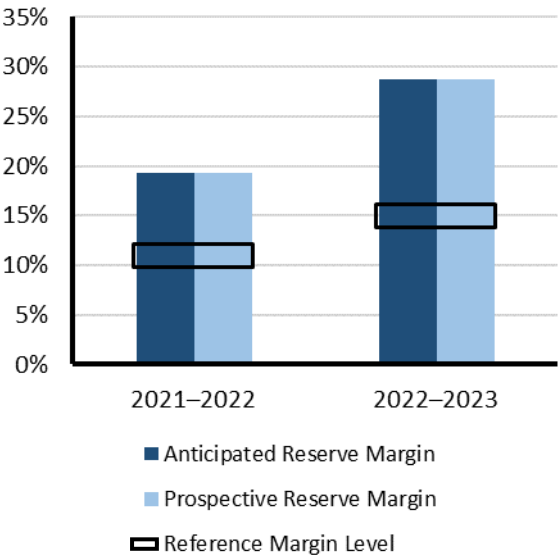
Highlights

- SaskPower experiences peak load in winter because of extreme cold weather. Reserve margins have increased since the 2021–2022 winter with the addition of new wind generators and increased firm capacity imports from Manitoba.
- SaskPower conducts an annual winter joint operating study with Manitoba Hydro with inputs from Basin Electric Power Cooperative (North Dakota) and prepares operating guidelines for any identified issues.
- The risk of operating reserve shortage or EEA during peak load times exists if large generation forced outage occurs during peak load times combined with transmission tie-line maintenance work or generation maintenance work scheduled during winter months.
- In case of extreme winter conditions combined with large generation forced outages, SaskPower would use available demand response programs, short-term power transfers from neighboring utilities, maintenance rescheduling, and/or short-term load interruptions.

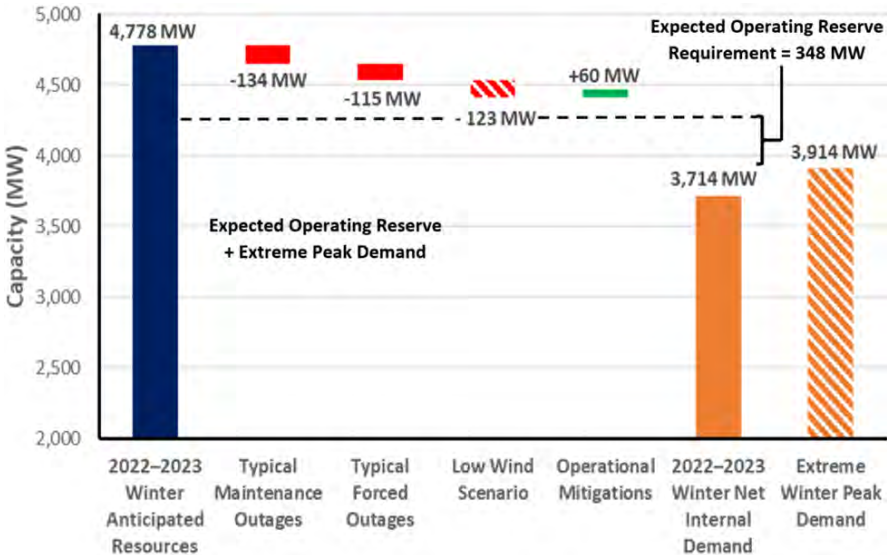
Risk Scenario Summary

Expected resources meet operating reserve requirements under the assessed scenarios.

On-Peak Reserve Margins



Risk-Period Scenario



Scenario Description (See [Data Concepts and Assumptions](#))

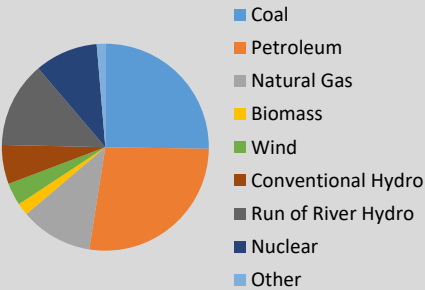
- Risk Period:** Highest risk for unserved energy at peak demand hour
- Demand Scenarios:** Net internal demand (50/50) and above-normal scenario based on peak demand with lighting and all consumer loads
- Maintenance Outages:** Average of planned maintenance outages for the winter months, December–February, over the past three years
- Forced Outages:** Estimated using SaskPower forced outage model
- Low Wind Scenario:** Estimated using SaskPower forced outage model
- Operational Mitigations:** Estimated average value based on short term transfer capability from neighboring utilities for the upcoming 2022–2023 winter



NPCC-Maritimes

The Maritimes assessment area is a winter-peaking NPCC area that contains two Balancing Authorities. It is comprised of the Canadian provinces of New Brunswick, Nova Scotia, and Prince Edward Island, and the northern portion of Maine, which is radially connected to the New Brunswick power system. The area covers 58,000 square miles with a total population of 1.9 million.

On-Peak Fuel Mix



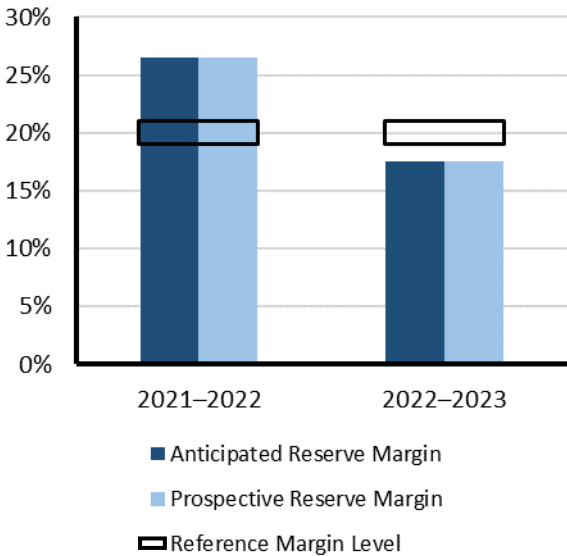
Highlights

- The Maritimes area has not identified any operational issues that are expected to impact system reliability. If an event was to occur, there are emergency operations and planning procedures in place.
- The Maritimes area is a winter-peaking system. All of the area’s declared firm capacity is expected to be operational for the winter operating period.
- As part of the planning process, dual-fueled units will have sufficient supplies of heavy fuel oil on-site to enable sustained operation in the event of natural gas supply interruptions.
- The results (preliminary) of NPCC’s probabilistic assessment indicate that established operating procedures are sufficient to maintain a balance between electricity supply and demand.¹¹ Only the low likelihood reduced resource case, highest peak load scenario, resulted in an estimated cumulative loss of load expectation (LOLE) risk of ~0.2 days/period with associated loss of load hours (LOLH) (<1 hours/period) and expected unsupplied energy (EUE) (3.4 MWh) over the winter period. The Maritimes area’s low likelihood resource case assumed that wind capacity was de-rated by half (1,100 to 550 MW) for every hour in the winter period, coupled with an assumed 50% reduction in natural-gas-fired generation and reduced transfer capabilities.

Risk Scenario Summary

Expected resources do not meet operating reserve requirements under normal peak-demand scenarios. Normal winter peak load and outage conditions could result in the need to employ operating mitigations (i.e., demand response, transfers, appeals) and EEAs. As noted above, the risk of load shedding is low.

On-Peak Reserve Margins



Risk-Period Scenario



Scenario Description (See [Data Concepts and Assumptions](#))

Risk Period: Highest risk for unserved energy at peak demand hour

Demand Scenarios: Net internal demand (50/50) and (above 90/10) extreme demand forecast.

Outages: Based on historical operating experience

Extreme Derates: A low likelihood scenario resulting in an additional 50% derate in the remaining capacity of both natural gas and wind resources under extreme conditions.

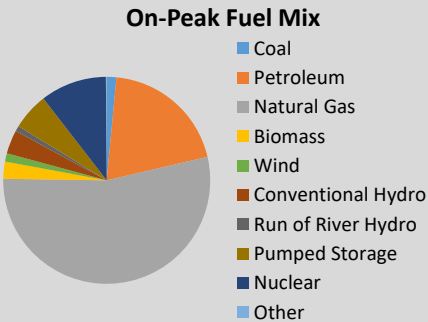
¹¹ Final NPCC Assessment Results will be published at the NPCC Seasonal Assessments page: <https://www.npcc.org/library/reports/seasonal-assessment>



NPCC-New England

NPCC-New England is an assessment area consisting of the states of Connecticut, Maine, Massachusetts, New Hampshire, Rhode Island, and Vermont served by ISO New England (ISO-NE) Inc. ISO-NE is a regional transmission organization responsible for the reliable day-to-day operation of New England’s bulk power generation and transmission system, administration of the area’s wholesale electricity markets, and management of the comprehensive planning of the regional BPS.

The New England BPS serves approximately 14.5 million customers over 68,000 square miles.



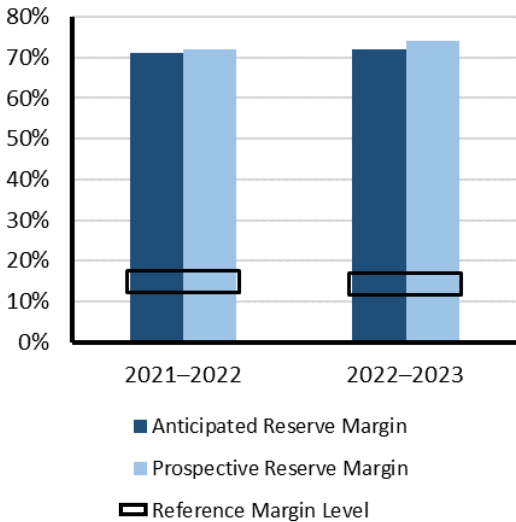
Highlights

- ISO-NE expects to meet its regional resource adequacy requirements this 2022–2023 winter operating period for a mild or moderate winter similar to 2021–2022 or 2017–2018. A standing concern is whether there will be sufficient energy available to satisfy electricity demand during an extended cold spell given the existing resource mix, fuel delivery infrastructure, and expected fuel arrangements without considerable effort to replenish stored fuels (i.e., fuel oil and LNG).
- ISO-NE expects to have sufficient capacity resources to meet the 2022–2023 90/10 winter peak demand forecast of 20,695 MW for the weeks beginning January 8, January 15, and January 22, 2023.
- ISO-NE evaluates an above 90/10 scenario that captures the area’s coldest day in the last 25 years while using both our current and future load models. The above 90/10 winter peak demand forecast is 21,238 MW for the three previously identified peak weeks. ISO-NE currently has sufficient resources to meet this demand; however, if a cold snap were to occur, the area may have to rely on its external ties and emergency procedures to operate reliably.¹²

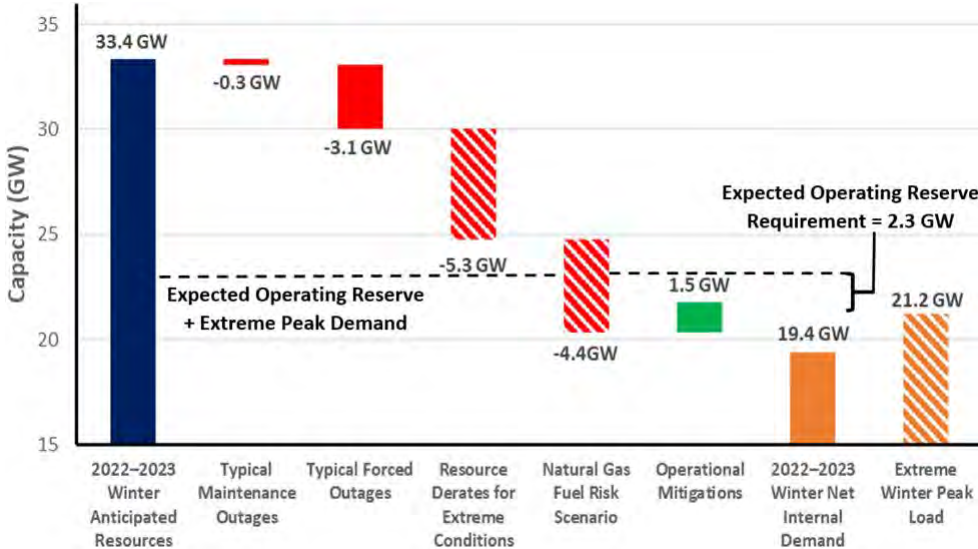
Risk Scenario Summary

Expected resources meet operating reserve requirements under normal peak-demand scenarios. Above-normal winter peak load and outage conditions could result in the need to employ operating mitigations (i.e., demand response and transfers) and EEAs. Load shedding is unlikely but may be needed under wide-area cold weather events.

On-Peak Reserve Margins



Risk-Period Scenario



Scenario Description (See [Data Concepts and Assumptions](#))

Risk Period: Highest risk for unserved energy at peak demand hour

Demand Scenarios: Net internal demand (50/50) and demand forecast for coldest day from the last 25 years

Maintenance and Forced Outages: Based on weekly averages

Extreme Derates and Natural Gas Scenario: Represent a case that is beyond the (90/10) conditions based on historical observation of force outages and additional reductions for generation at risk due to natural gas supply and cold weather related outages reported by generators

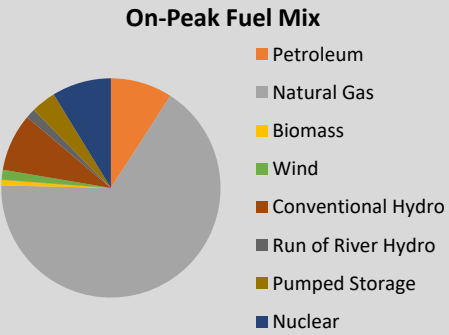
Operational Mitigations: Based on ISO-NE operating procedures

¹² Final NPCC Assessment Results will be published at the NPCC Seasonal Assessments page: <https://www.npcc.org/library/reports/seasonal-assessment>



NPCC-New York

NPCC-New York is an assessment area consisting of the New York ISO (NYISO) service territory. NYISO is responsible for operating New York’s BPS, administering wholesale electricity markets, and conducting system planning. The NYISO is the only Balancing Authority within the state of New York. The BPS encompasses over 11,000 miles of transmission lines, 760 power generation units, and serves 20.2 million customers. The established Reference Margin Level is 15%. Wind, grid-connected solar, and run-of-river totals were derated for this calculation. However, New York requires load serving entities to procure capacity for their loads equal to their peak demand plus an IRM. The IRM requirement represents a percentage of capacity above peak load forecast and is approved annually by the New York State Reliability Council (NYSRC). NYSRC approved the 2022–2023 IRM at 19.6%.

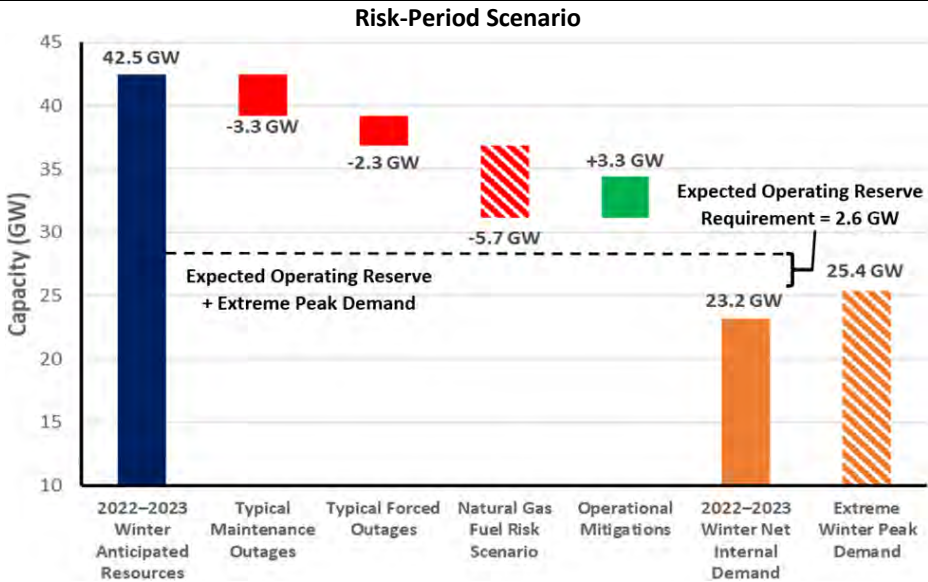
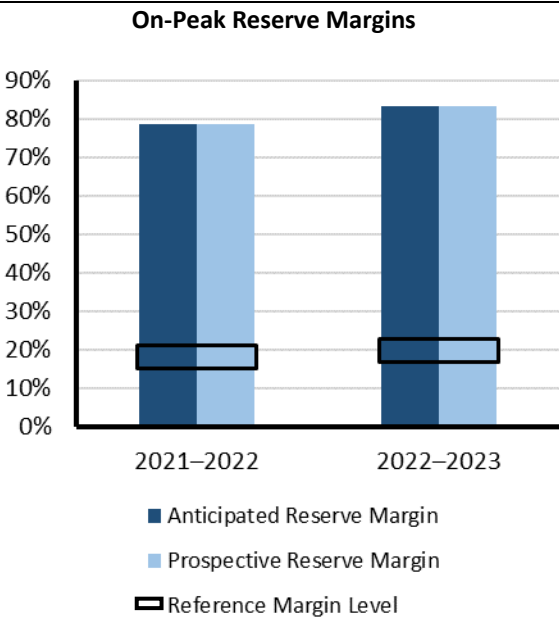


Highlights

- New York is a summer peaking area and no emerging reliability issues are anticipated during the 2022–2023 winter assessment period. Surplus capacity margins above the NYISO’s operating reserve requirements are projected.
- The results (preliminary) of NPCC’s probabilistic assessment for the area indicate that emergency operating procedures to maintain a balance between electricity supply and demand are not anticipated for the upcoming winter. No cumulative LOLE, LOLH, or EUE risks were found for the winter period for all modeled scenarios.¹³

Risk Scenario Summary

Expected resources meet operating reserve requirements under assessed scenarios.



Scenario Description (See [Data Concepts and Assumptions](#))

- Risk Period:** Highest risk for unserved energy at peak demand hour
- Demand Scenarios:** Net internal demand (50/50) and (99/1) demand forecast with demand response adjustments
- Maintenance Outages:** Based on planned scheduled maintenance
- Forced Outages:** Based on historical 5-year averages
- Natural Gas Fuel Scenario:** Potential natural gas generation at risk if non-firm supply is unavailable in a period of extended cold weather
- Operational Mitigations:** Based on NYISO operating procedures

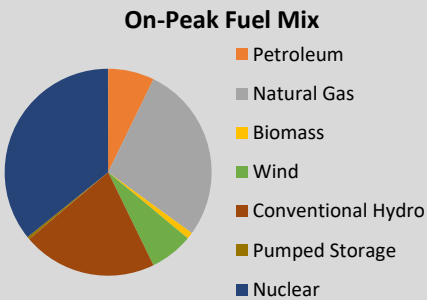
¹³ Final NPCC Assessment Results will be published at the NPCC Seasonal Assessments page: <https://www.npcc.org/library/reports/seasonal-assessment>



NPCC-Ontario

NPCC-Ontario is an assessment area in the Ontario province of Canada. The Independent Electricity System Operator (IESO) is the Balancing Authority for the province of Ontario. The province of Ontario covers more than 1 million square kilometers (415,000 square miles) and has a population of more than 14 million.

Ontario is interconnected electrically with Québec, MRO-Manitoba, states in MISO (Minnesota and Michigan), and NPCC-New York.



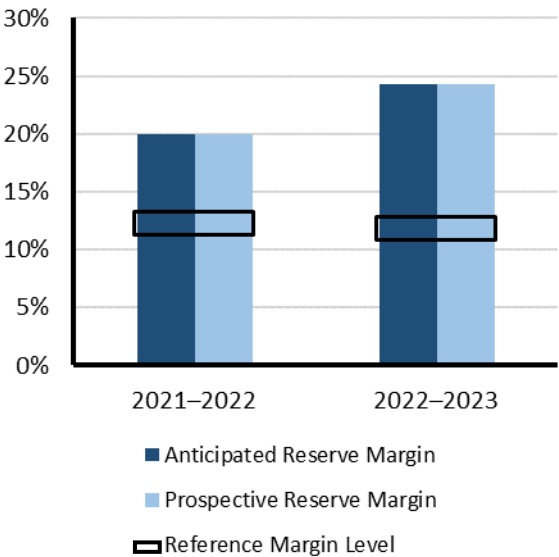
Highlights

- IESO anticipates that it will maintain reliability on its system through the 2022–2023 winter
- In spite of Ontario’s ongoing nuclear refurbishment program, the IESO expects to have comfortable reserve margins throughout the winter season
- The results (preliminary) of NPCC’s probabilistic assessment for the area indicate that emergency operating procedures to maintain a balance between electricity supply and demand are not anticipated for the upcoming winter. No cumulative LOLE, LOLH or EUE risks were found for the winter period for all modeled scenarios.¹⁴

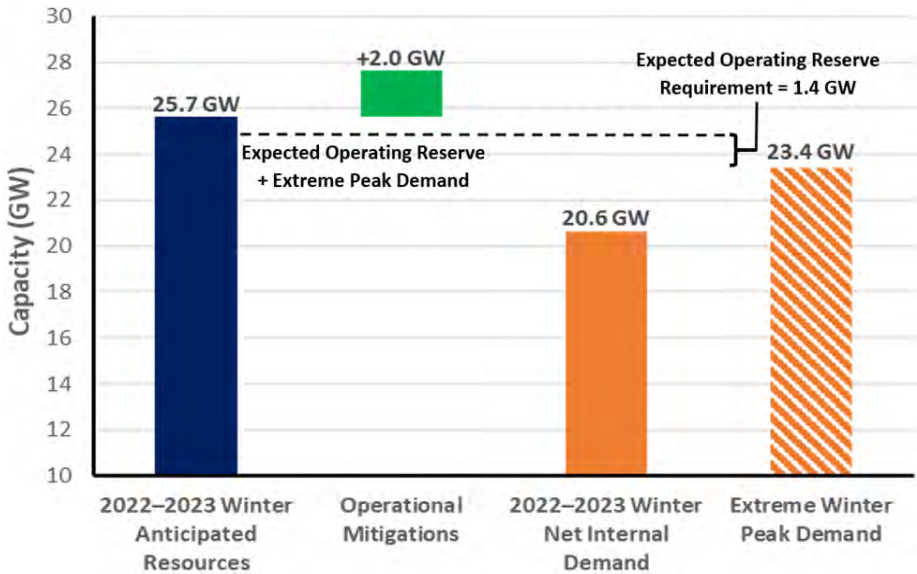
Risk Scenario Summary

Expected resources meet operating reserve requirements under the assessed scenarios.

On-Peak Reserve Margins



Risk-Period Scenario



Scenario Description (See [Data Concepts and Assumptions](#))

Risk Period: Highest risk for unserved energy at peak demand hour

Demand Scenarios: Net internal demand (50/50 Forecast) and highest weather-adjusted daily demand from 31 years of winter demand history

Operational Mitigations: Imports anticipated from neighbors during emergencies

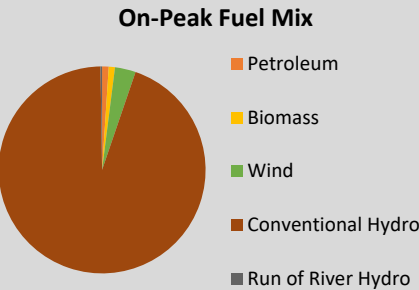
¹⁴ Final NPCC Assessment Results will be published at the NPCC Seasonal Assessments page: <https://www.npcc.org/library/reports/seasonal-assessment>



NPCC-Québec

The Québec assessment area (Province of Québec) is a winter-peaking NPCC area that covers 595,391 square miles with a population of 8 million.

Québec is one of the four Interconnections in North America; it has ties to Ontario, New York, New England, and the Maritimes; consisting of either HVDC ties, radial generation, or load to and from neighboring systems.



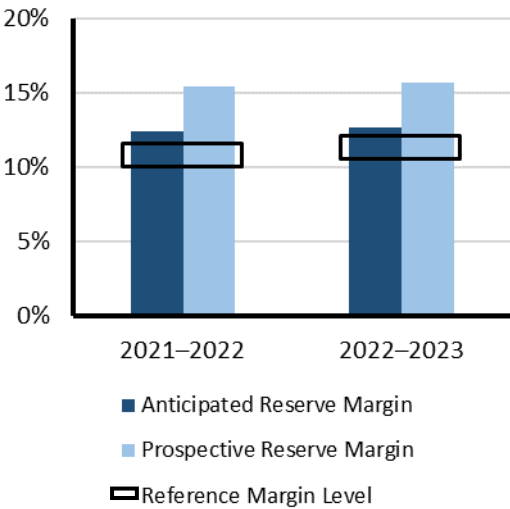
Highlights

- Québec is expecting to maintain system resource adequacy this winter.
- The Québec area is a winter-peaking system with predominately hydroelectric generation resources. Adequate capacity margins above its reference reserve requirements are projected for the 2022–2023 winter assessment period.
- No changes have been made to the assessment area’s winter preparedness programs since the previous winter season.
- The results (preliminary) of NPCC’s probabilistic assessment for the area indicate that emergency operating procedures to maintain a balance between electricity supply and demand are not anticipated for the upcoming winter. No cumulative LOLE, LOLH, or EUE risks were found for the winter period for all modeled scenarios.¹⁵

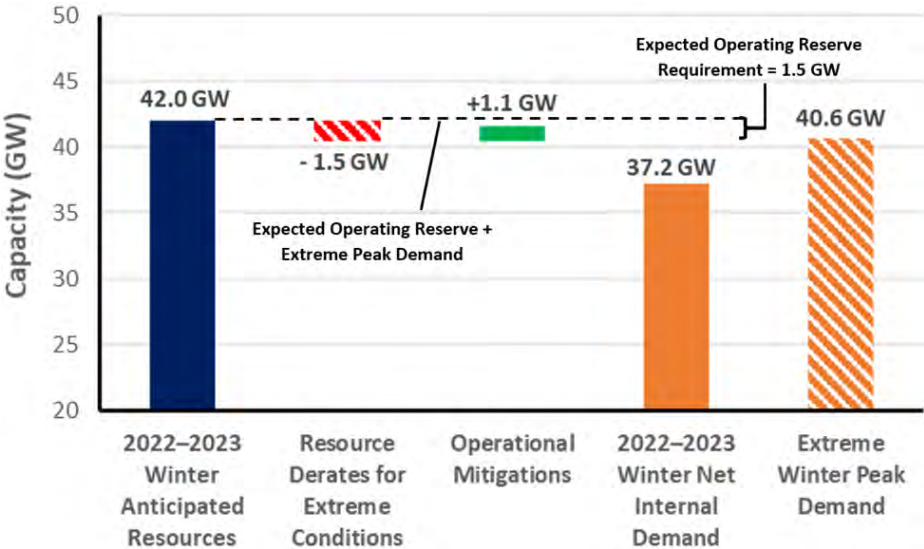
Risk Scenario Summary

Expected resources meet operating reserve requirements under normal peak-demand scenarios. Québec plans to use short-term capacity purchases in order to meet capacity requirements when needed. Above-normal winter peak load and outage conditions could result in the need to employ operating mitigations (i.e., demand response and transfers) and EEAs. As noted above, risk of load shedding is low.

On-Peak Reserve Margins



Risk-Period Scenario



Scenario Description (See [Data Concepts and Assumptions](#))

- Risk Period:** Highest risk for unserved energy at peak demand hour
- Demand Scenarios:** Net internal demand (50/50) and extreme demand represents two standard deviations higher than the mean demand forecast
- Extreme Derates:** Rare scenario of 1,500 MW in unplanned outages
- Operational Mitigations:** Imports anticipated from neighbors during emergencies

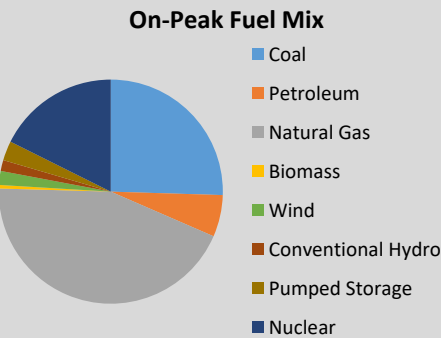
¹⁵ Final NPCC Assessment Results will be published at the NPCC Seasonal Assessments page: <https://www.npcc.org/library/reports/seasonal-assessment>



PJM

PJM Interconnection is a regional transmission organization that coordinates the movement of wholesale electricity in all or parts of Delaware, Illinois, Indiana, Kentucky, Maryland, Michigan, New Jersey, North Carolina, Ohio, Pennsylvania, Tennessee, Virginia, West Virginia, and the District of Columbia. PJM serves 65 million customers and covers 369,089 square miles.

PJM is a Balancing Authority, Planning Coordinator, Transmission Planner, Resource Planner, Interchange Authority, Transmission Operator, Transmission Service Provider, and Reliability Coordinator.



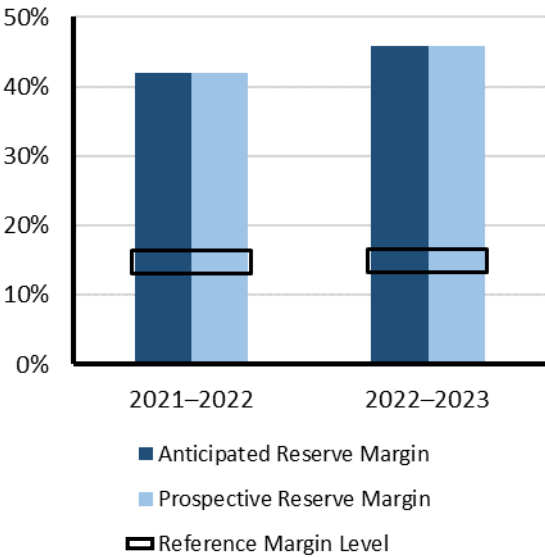
Highlights

- PJM expects no resource problems over the entire 2022–2023 winter peak season because installed capacity is almost three times the reserve requirement.
- No other reliability concerns are expected.

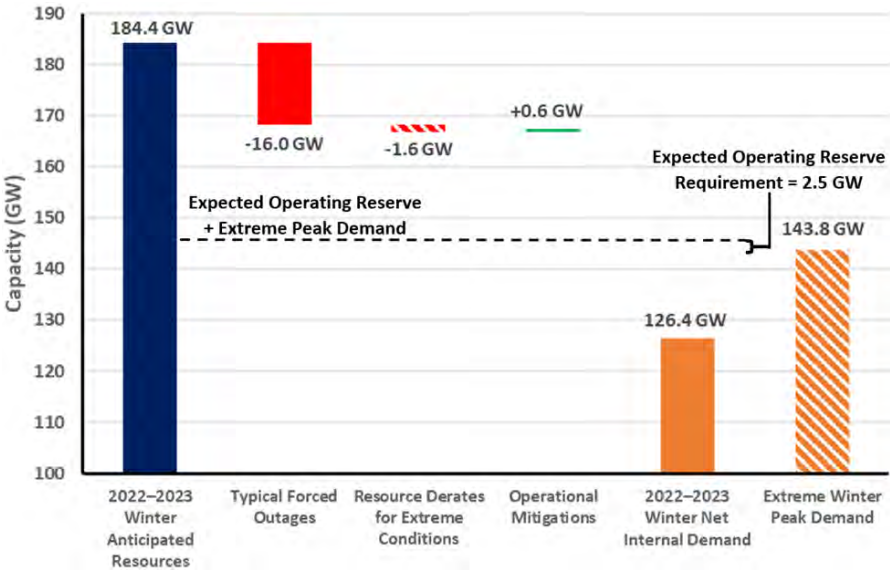
Risk Scenario Summary

Expected resources meet operating reserve requirements under assessed scenarios.

On-Peak Reserve Margins



Risk-Period Scenario



Scenario Description (See [Data Concepts and Assumptions](#))

- Risk Period:** Highest risk for unserved energy at peak demand hour
- Demand Scenarios:** Net internal demand (50/50) and (90/10) demand forecast
- Outages:** Based on historical data and trending
- Extreme Derates:** Accounts for reduced thermal capacity contributions due to performance in extreme conditions
- Operational Mitigations:** A total of 0.6 GW based on operational/emergency procedures

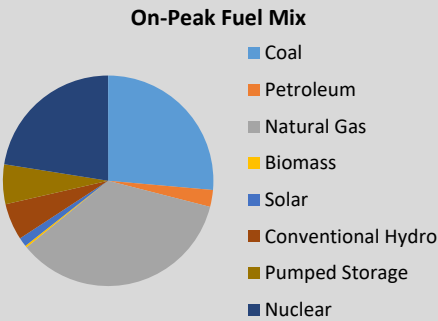


SERC-East

SERC-East is a winter-peaking assessment area within the SERC Regional Entity. SERC-East includes North Carolina and South Carolina.

SERC is one of the six companies across North America that are responsible for the work under Federal Energy Regulatory Commission approved delegation agreements with NERC. SERC is specifically responsible for the reliability and security of the electric grid across the Southeastern and Central areas of the United States. This area covers approximately 630,000 square miles and serves a population of more than 91 million.

The SERC Regional Entity includes 36 Balancing Authorities, 28 Planning Authorities, and 6 Reliability Coordinators.

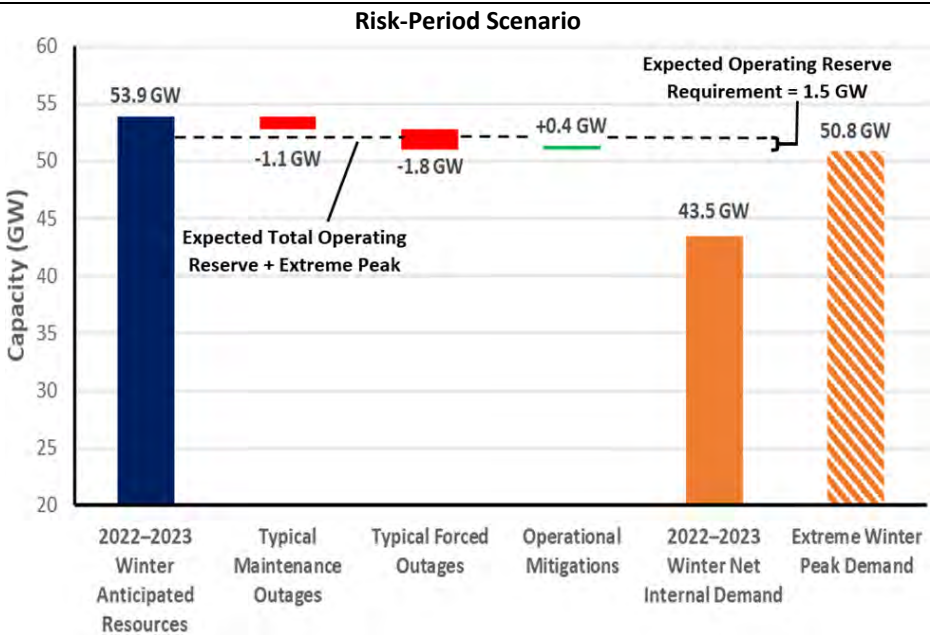
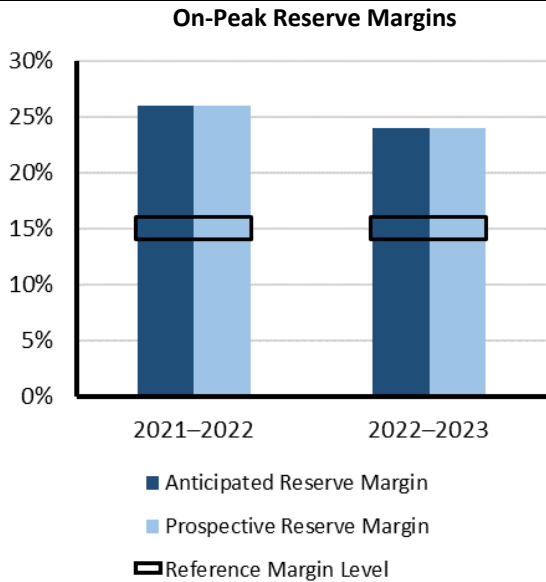


Highlights

- SERC-East has not identified any emerging or potential reliability issues for the upcoming winter season.
- Currently, there are issues with fuel supply and transportation in the SERC-East assessment area. Transportation providers and coal suppliers continue to struggle with post pandemic personnel shortages, volume increases, and inflationary cost increases. SERC-East does not anticipate any significant reliability issues because of fuel supply, inventory, or transportation.
- SERC-East has extensive weatherization processes that include procedures specific to freezing events. SERC-East is prepared to respond to unexpected day-to-day events and coordinate with neighboring entities to promote overall system reliability.

Risk Scenario Summary

Expected resources meet operating reserve requirements under normal peak-demand scenarios. Above-normal winter peak load and outage conditions could result in the need for non-firm transfers, operating mitigations and EEAs. Risk of load shedding is low.



Scenario Description (See [Data Concepts and Assumptions](#))

- Risk Period:** Highest risk for unserved energy at peak demand hour
- Demand Scenarios:** Net internal demand (50/50) and (90/10) demand forecast
- Maintenance Outages:** Data collected through a survey of members for outages during December through February
- Forced Outages:** Weighted average forced outage rates on-peak are factored into the anticipated resources calculation
- Operational Mitigations:** A total of 0.4 GW based on operational/emergency procedures



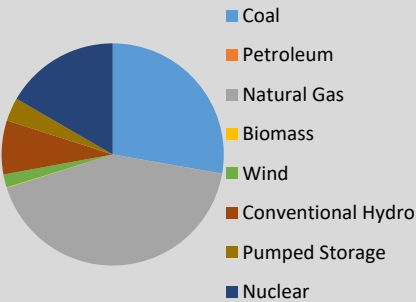
SERC-Central

SERC-Central is a winter-peaking assessment area within the SERC Regional Entity. SERC-Central includes all of Tennessee and portions of Georgia, Alabama, Mississippi, Missouri, and Kentucky.

SERC is one of the six companies across North America that are responsible for the work under Federal Energy Regulatory Commission approved delegation agreements with NERC. SERC-Central is specifically responsible for the reliability and security of the electric grid across the Southeastern and Central areas of the United States. This area covers approximately 630,000 square miles and serves a population of more than 91 million.

The SERC Regional Entity includes 36 Balancing Authorities, 28 Planning Authorities, and 6 Reliability Coordinators.

On-Peak Fuel Mix



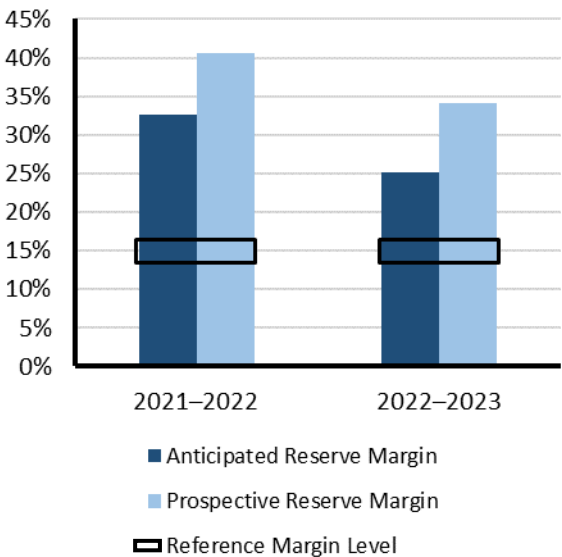
Highlights

- SERC-Central has not identified any emerging or potential reliability issues for the upcoming winter season.
- SERC-Central does not anticipate any significant reliability issues because of fuel supply, inventory, or transportation.
- SERC-Central has extensive weatherization processes that include procedures specific to freezing events and is prepared to respond to unexpected day-to day-events and coordinate with neighboring entities to promote overall system reliability.

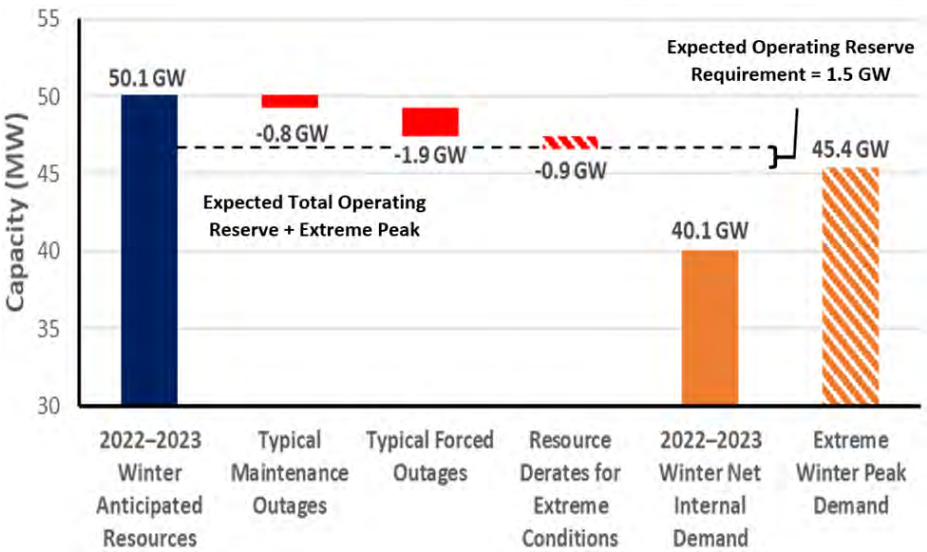
Risk Scenario Summary

Expected resources meet operating reserve requirements under assessed scenarios.

On-Peak Reserve Margins



Risk-Period Scenario



Scenario Description (See [Data Concepts and Assumptions](#))

Risk Period: Highest risk for unserved energy at peak demand hour

Demand Scenarios: Net internal demand (50/50) and (90/10) demand forecast

Maintenance Outages: Data collected through a survey of members for outages during December through February

Forced Outages: Weighted average forced outage rates on-peak are factored into the anticipated resources calculation

Extreme Derates: Accounts for reduced thermal capacity contributions due to performance in extreme conditions

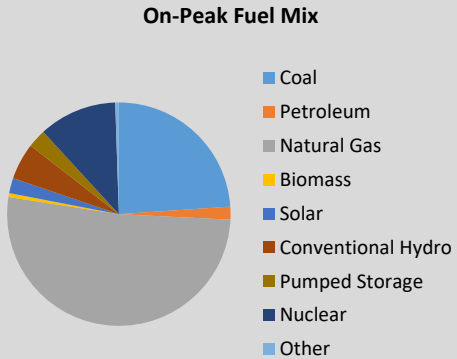


SERC-Southeast

SERC-Southeast is a winter-peaking assessment area within the SERC Regional Entity. SERC-Southeast includes all or portions of Georgia, Alabama, and Mississippi.

SERC is one of the six companies across North America that are responsible for the work under Federal Energy Regulatory Commission approved delegation agreements with NERC. SERC is specifically responsible for the reliability and security of the electric grid across the southeastern and central areas of the United States. This area covers approximately 630,000 square miles and serves a population of more than 91 million.

The SERC Regional Entity includes 36 Balancing Authorities, 28 Planning Authorities, and 6 Reliability Coordinators.



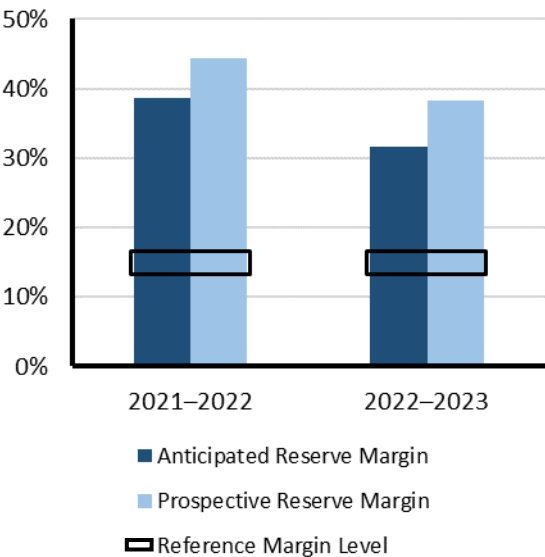
Highlights

- Aside from fuel availability concerns shared across the industry, SERC-Southeast have not identified any additional or emerging potential reliability related risks.
- SERC-Southeast has extensive weatherization processes that include procedures specific to freezing events and is prepared to respond to unexpected day-to-day events and coordinate with neighboring entities to promote overall system reliability.

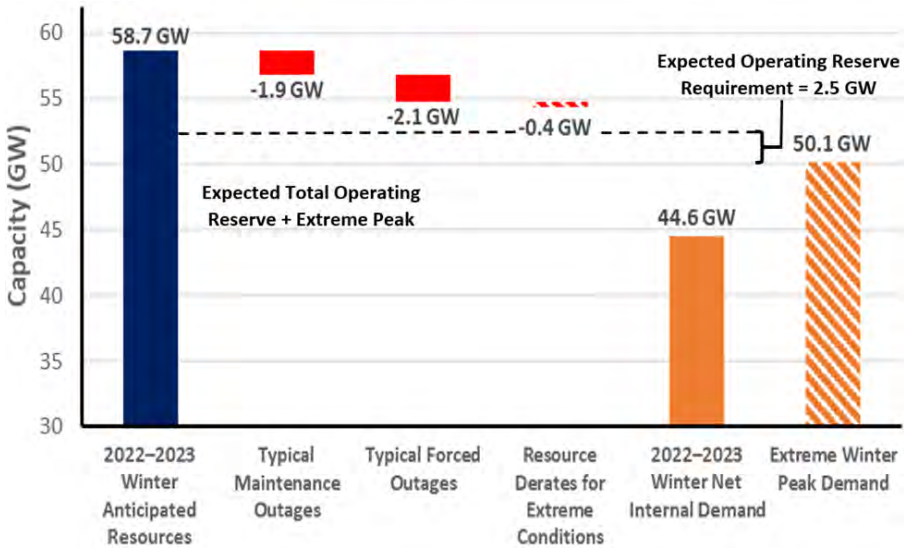
Risk Scenario Summary

Expected resources meet operating reserve requirements under assessed scenarios.

On-Peak Reserve Margins



Risk-Period Scenario



Scenario Description (See [Data Concepts and Assumptions](#))

- Risk Period:** Highest risk for unserved energy at peak demand hour
- Demand Scenarios:** Net internal demand (50/50) and (90/10) demand forecast
- Maintenance Outages:** Data collected through a survey of members for outages during December through February
- Forced Outages:** Weighted average forced outage rates on-peak are factored into the anticipated resources calculation
- Extreme Derates:** Accounts for reduced thermal capacity contributions due to performance in extreme conditions

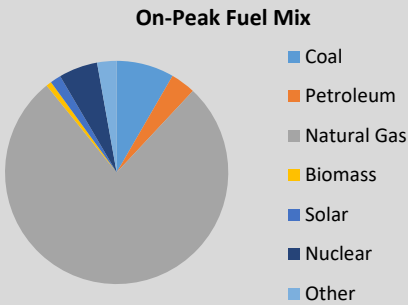


SERC-Florida Peninsula

SERC-Florida Peninsula is a summer-peaking assessment area within SERC.

SERC is one of the six companies across North America that are responsible for the work under Federal Energy Regulatory Commission approved delegation agreements with NERC. SERC is specifically responsible for the reliability and security of the electric grid across the Southeastern and Central areas of the United States. This area covers approximately 630,000 square miles and serves a population of more than 91 million.

The SERC Regional Entity includes 36 Balancing Authorities, 28 Planning Authorities, and 6 Reliability Coordinators.



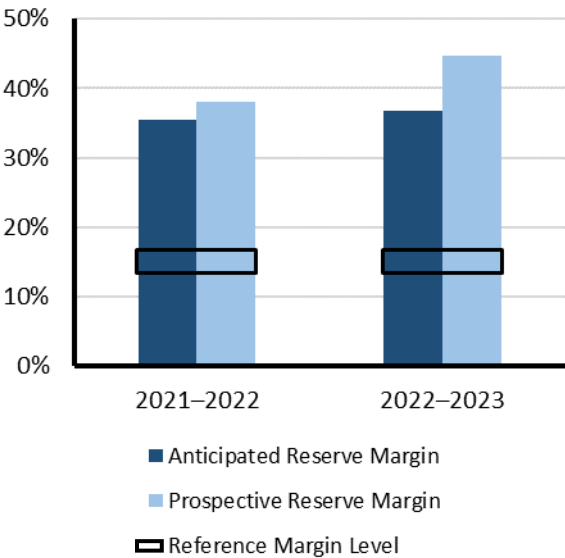
Highlights

- SERC-Florida Peninsula have not identified any emerging or potential reliability issues for the upcoming winter season.
- SERC-Florida Peninsula do not anticipate any significant reliability issues because of fuel supply, inventory, or transportation.
- SERC-Florida Peninsula have extensive weatherization processes that include developing procedures specific to freezing events.

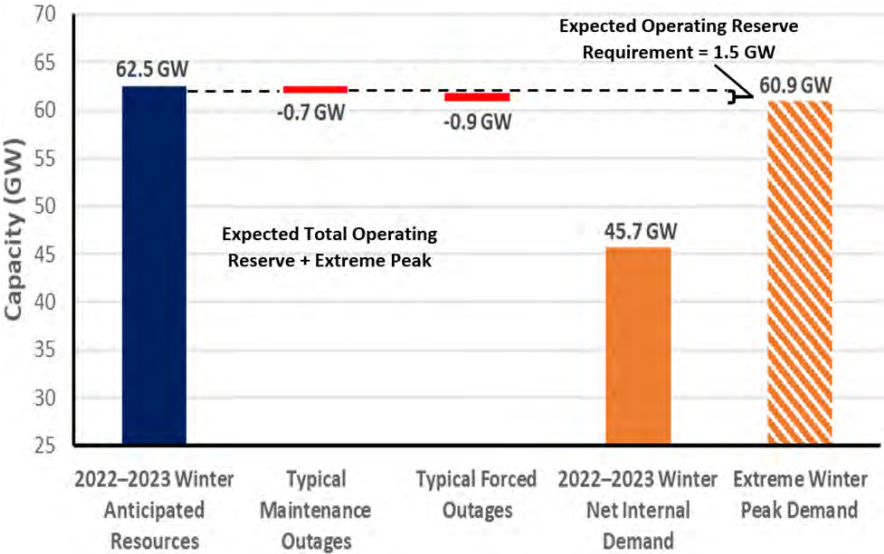
Risk Scenario Summary

Expected resources meet operating reserve requirements under normal peak-demand scenarios. Above-normal winter peak load and outage conditions could result in the need to employ operating mitigations (i.e., demand response and transfers) and EEAs.

On-Peak Reserve Margins



Risk-Period Scenario



Scenario Description (See [Data Concepts and Assumptions](#))

Risk Period: Highest risk for unserved energy at peak demand hour

Demand Scenarios: Net internal demand (50/50) and (95/5) demand forecast

Maintenance Outages: Data collected through a survey of members for outages during December through February

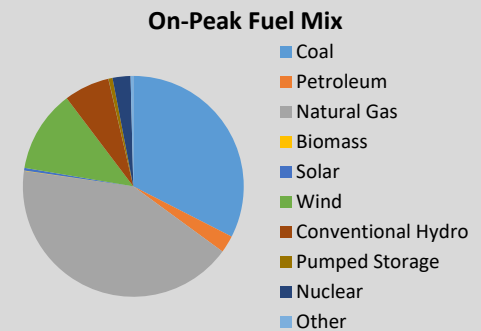
Forced Outages: Weighted average forced outage rates on-peak are factored into the anticipated resources calculation



SPP

Southwest Power Pool (SPP) Planning Coordinator footprint covers 546,000 square miles and encompasses all or parts of Arkansas, Iowa, Kansas, Louisiana, Minnesota, Missouri, Montana, Nebraska, New Mexico, North Dakota, Oklahoma, South Dakota, Texas, and Wyoming.

The SPP long-term assessment is reported based on the Planning Coordinator footprint, which touches parts of the Midwest Reliability Organization Regional Entity and the WECC Regional Entity. The SPP assessment area footprint has approximately 61,000 miles of transmission lines, 756 generating plants, and 4,811 transmission-class substations, and it serves a population of more than 18 million.



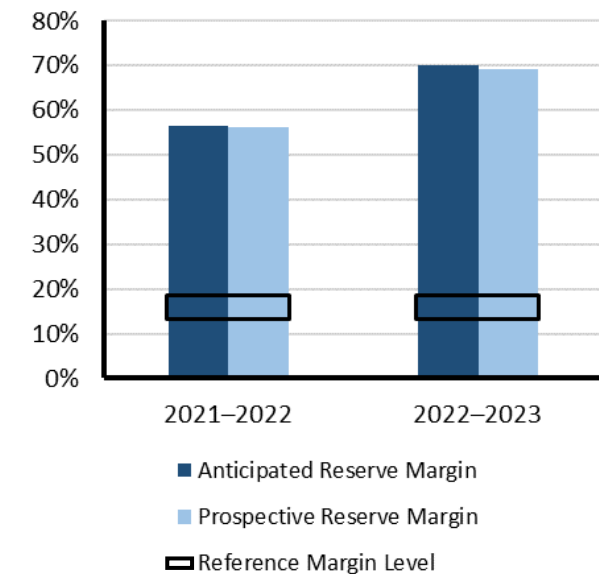
Highlights

- SPP’s planning reserves are adequate for the upcoming winter season. Since the 2021–2022 winter, SPP has added 3,700 MW of natural-gas-fired generation.
- SPP does not anticipate any emerging reliability issues impacting the area for the 2022–2023 winter season but realizes that interruptions to fuel supply could create unique operation challenges.
- SPP continues to work with neighboring areas to address potential electric deliverability issues associated with extreme weather events. Efforts focus on enhancing communications and operator preparedness.
- In an effort to minimize the need for conservative operations, EEAs, and the responses to mid-range forecast error uncertainty in wind forecasts, SPP created some new mitigation processes to deal with high impact areas of concern. SPP has developed operational mitigation teams, processes, and procedures that have been put in place to maintain real time reliability needs.
- SPP created the Improved Resource Availability Task Force , which will take primary responsibility for addressing Tier 1 recommendations related to fuel assurance and resource planning and availability identified in the [Comprehensive Review of SPP's Response to the February 2021 Winter Storm](#) report.
- SPP hosts its winter preparedness workshop in October 2022.

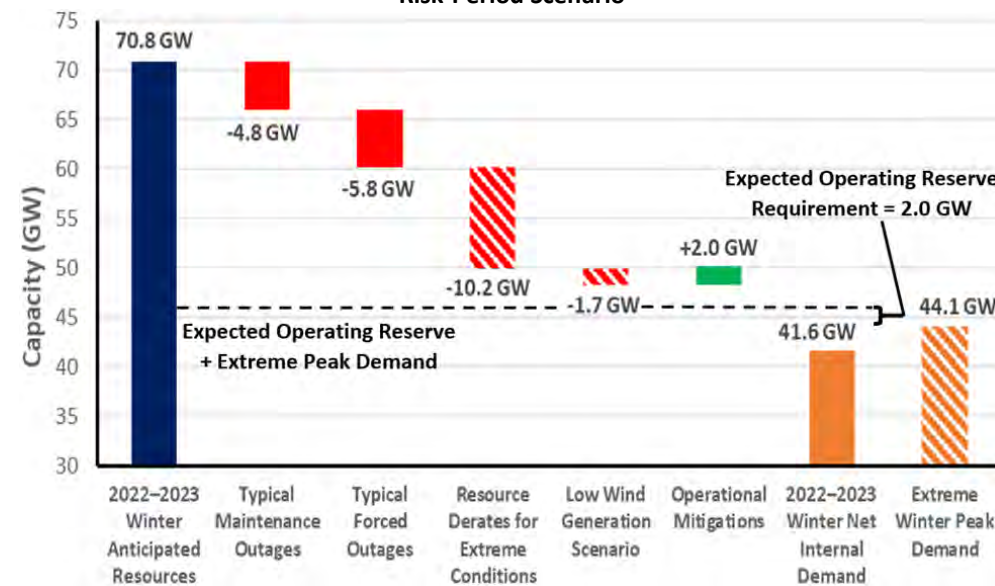
Risk Scenario Summary

Expected resources meet operating reserve requirements under assessed scenarios.

On-Peak Reserve Margins



Risk-Period Scenario



Scenario Description (See [Data Concepts and Assumptions](#))

Risk Period: Highest risk for unserved energy at peak demand hour

Demand Scenarios: Net internal demand (50/50) and (90/10) demand forecast

Maintenance and Forced Outages: A capacity derate for maintenance outages, forced outages, and performance in extreme weather based on historical data

Extreme Derates: A capacity derate for generator performance in extreme weather based on historical data

Low Wind Scenario: 1.7 GW of wind potentially off-line when temperatures fall below their cold weather performance packages

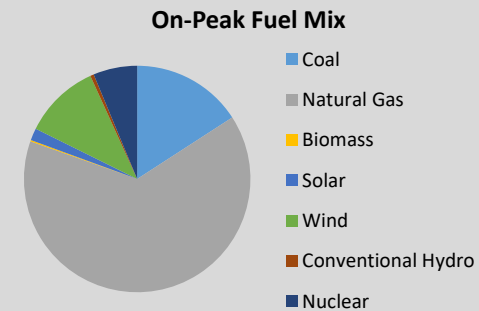
Operational Mitigations: A total of 2 GW based on operational/emergency procedures (External Assistance)



Texas RE-ERCOT

The Electric Reliability Council of Texas (ERCOT) is the ISO for the ERCOT Interconnection and is located entirely in the state of Texas; it operates as a single BA. It also performs financial settlement for the competitive wholesale bulk-power market and administers retail switching for nearly 8 million premises in competitive choice areas. ERCOT is governed by a board of directors and subject to oversight by the Public Utility Commission of Texas and the Texas Legislature.

ERCOT is summer-peaking. It covers approximately 200,000 square miles, connects over 46,500 miles of transmission lines, has over 710 generation units, and serves more than 25 million people. Lubbock Power & Light joined the ERCOT grid on June 1, 2021. Texas Regional Entity is responsible for the Regional Entity functions described in the Energy Policy Act of 2005 for ERCOT.

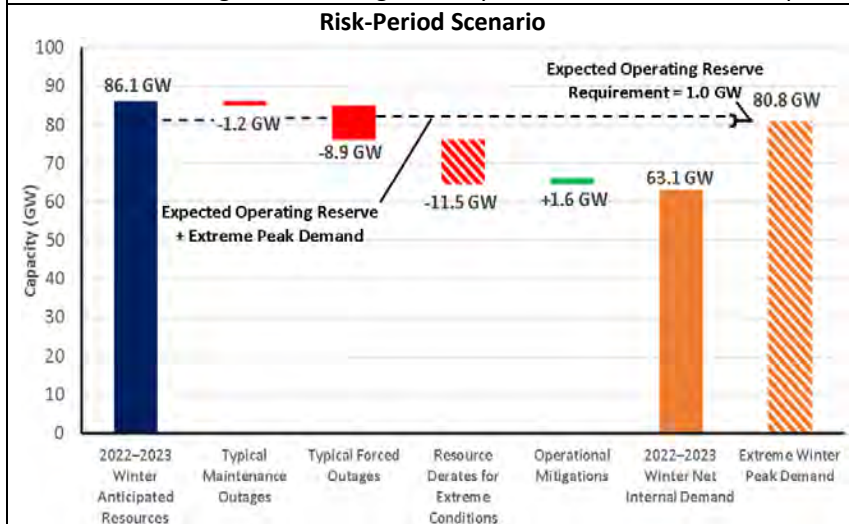
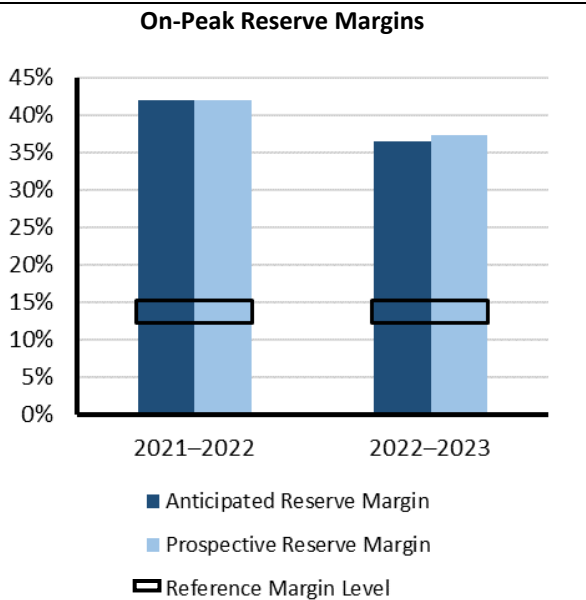


Highlights

- With an Anticipated Reserve Margin of 36.4%, capacity reserves are sufficient to meet forecasted peak demand to cover the types of weather events regularly experienced.
- Probabilistic risk assessment for the upcoming winter season confirms a low probability of energy emergency events occurring during the expected peak load hour (hour-ending 8:00 a.m.) and other higher-risk hours. The assessment accounts for the risk of another weather event like Winter Storm Uri as well as the impacts of winter preparedness standards implemented by the Public Utility Commission of Texas and the TRRC, which regulates the Texas fuel oil and natural gas industries.
- ERCOT conducted 324 weather preparedness inspections during 2021, covering 302 generation sites and 22 transmission service providers. These inspections focused on whether each reporting entity performed the weatherization activities described in their winter weather readiness reports required by the PUCT. ERCOT has been working with the PUCT on development of Phase II of the preparedness standards, which addresses both winter and summer preparedness compliance.
- The U.S. EPA is proposing a “conditional acceptance” of CPS Energy’s plan to address two ponds at the coal-fired Calaveras Spruce station that are not in compliance with EPA regulations for coal combustion residuals. If the generation units at the site (J.K. Spruce 1 and 2: 1,477 MW) are found to be needed for grid reliability, then the EPA would allow ERCOT and CPS Energy to plan the outages to best minimize reliability issues during the outage period. If the EPA denies the conditional acceptance, then the Spruce units would cease operations 135 days after the EPA denial decision is made.

Risk Scenario Summary

Expected resources meet operating reserve requirements under normal peak-demand scenarios. Above-normal winter peak load and outage conditions could result in the need to employ operating mitigations (i.e., demand response and transfers) and EEAs, including load shedding that may be needed under extreme peak demand and outage scenarios studied.



Scenario Description (See [Data Concepts and Assumptions](#))

Risk Period: Highest risk for unserved energy at peak demand hour

Demand Scenarios: Net internal demand (50/50) and extreme winter peak demand based on 2020–2021 winter storm Uri peak demand

Maintenance and Forced Outages: Based on the historical averages of maintenance or forced outages respectively for December through February weekdays, hours ending 7:00–10:00 a.m. local time for the last three (2019/2020, 2020/2021, and 2021/2022) winter seasons (Winter Storm Uri-related forced outages between February 15–18, 2021, were excluded from this calculation.)

Extreme Derates: Accounts for reduced thermal, wind, and solar PV capacity contributions due to performance in extreme conditions. Uses averages from Winter Storm URI with adjustments to account for implemented weatherization improvements.

Operational Mitigations: Additional capacity from switchable generation, additional imports, and voltage reduction

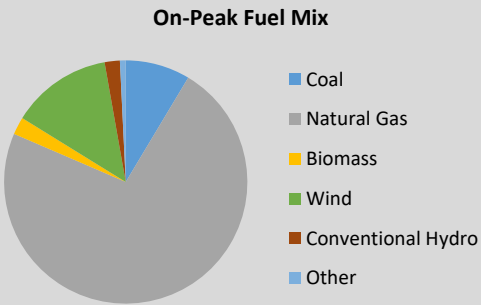


WECC-AB

WECC-AB (Alberta) is a winter-peaking assessment area in the WECC Regional Entity that consists of the province of Alberta, Canada.

WECC is responsible for coordinating and promoting BES reliability in the Western Interconnection. WECC’s 329 members include 39 Balancing Authorities, representing a wide spectrum of organizations with an interest in the BES. Serving an area of nearly 1.8 million square miles and more than 82 million customers, it is geographically the largest and most diverse Regional Entity.

WECC’s service territory extends from Canada to Mexico. It includes the provinces of Alberta and British Columbia in Canada, the northern portion of Baja California in Mexico as well as all or portions of the 14 Western United States in between.



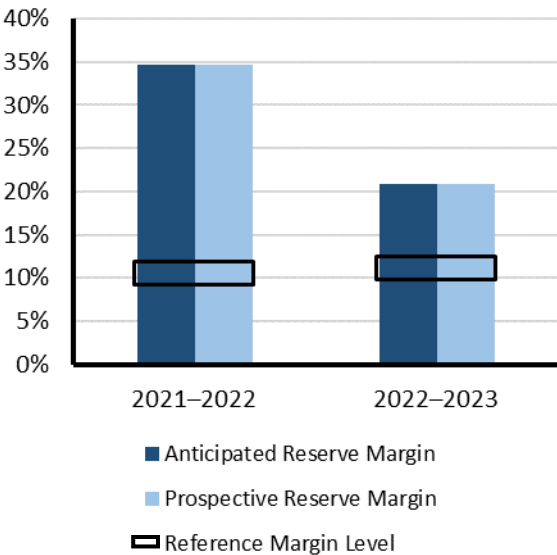
Highlights

- Alberta is a winter peaking area. Winter temperatures are forecast to be below normal. Alberta’s operating reserve margins are met before imports in all scenarios except the Low Wind, which leaves a gap of 0.1 GW, and the extreme combined scenario, which leaves a gap of 0.6 GW under extreme peak demand conditions. Both are anticipated to be able to be covered through imports.
- The drop in on-peak reserve margins between last winter and the upcoming winter is a reflection of a slight demand increase of 330 MW combined with roughly 1,500 MW less Tier 1 resources than in the last plan.

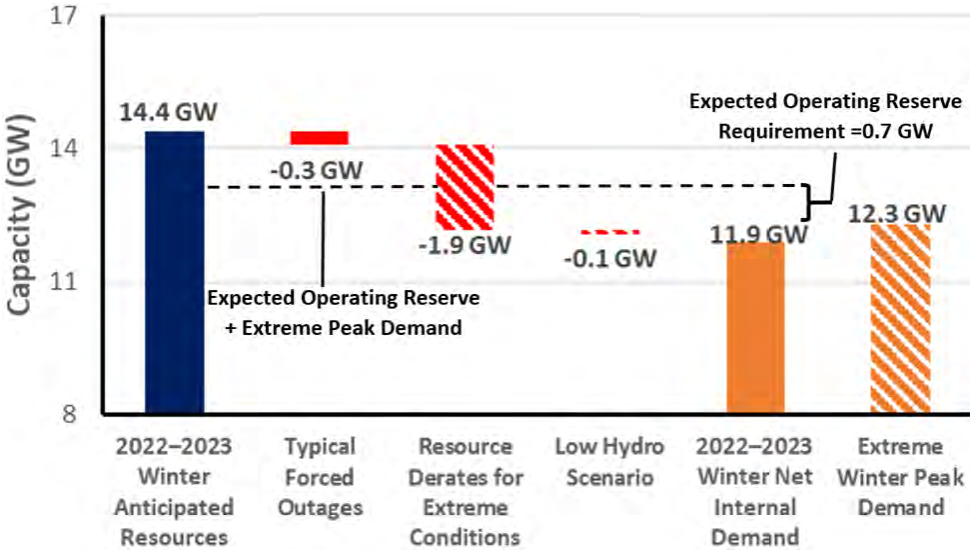
Risk Scenario Summary

Expected resources meet operating reserve requirements under normal peak-demand scenarios. Above-normal winter peak load and outage conditions could result in the need to employ operating mitigations (i.e., demand response and transfers) and EEAs. Risk of load shedding is low due to the expected availability of transfers from neighboring areas.

On-Peak Reserve Margins



Risk-Period Scenario



Scenario Description (See [Data Concepts and Assumptions](#))

- Risk Period:** Highest risk for unserved energy at peak demand hour
- Demand Scenarios:** Net internal demand (50/50) and (90/10) demand forecast
- Forced Outages:** Average seasonal outages
- Extreme Derates:** Using (90/10) scenario
- Low Hydro Scenario:** Reduced hydro output due to drought conditions



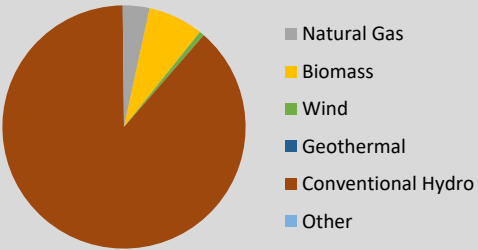
WECC-BC

WECC-BC (British Columbia) is a winter-peaking assessment area in the WECC Regional Entity that consists of the province of British Columbia, Canada.

WECC is responsible for coordinating and promoting BES reliability in the Western Interconnection. WECC’s 329 members include 39 Balancing Authorities, representing a wide spectrum of organizations with an interest in the BES. Serving an area of nearly 1.8 million square miles and more than 82 million customers, it is geographically the largest and most diverse Regional Entity.

WECC’s service territory extends from Canada to Mexico. It includes the provinces of Alberta and British Columbia in Canada, the northern portion of Baja California in Mexico as well as all or portions of the 14 Western United States in between.

On-Peak Fuel Mix



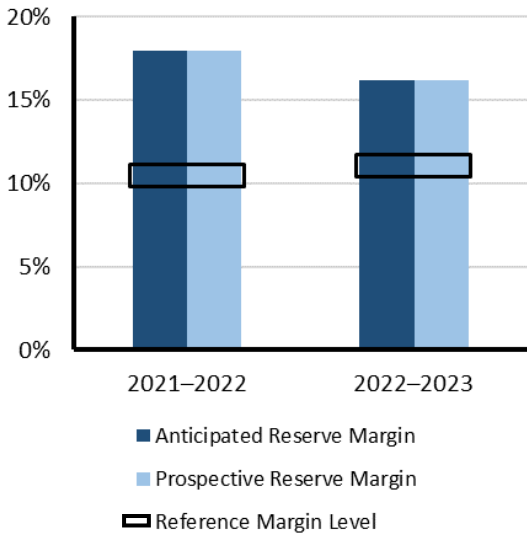
Highlight

- British Columbia is winter peaking with below normal temperatures forecast. In British Columbia before imports, operating reserve margins are not met by at least 0.4 GW in the occurrence of an extreme peak demand. However, the net internal demand is met before imports in all winter resource availability scenarios except under Low Hydro, which leaves an approximate gap of 1 GW, and Extreme Combined, which leaves a gap of 1.1 GW. Both of these are expected to be able to be covered through imports.

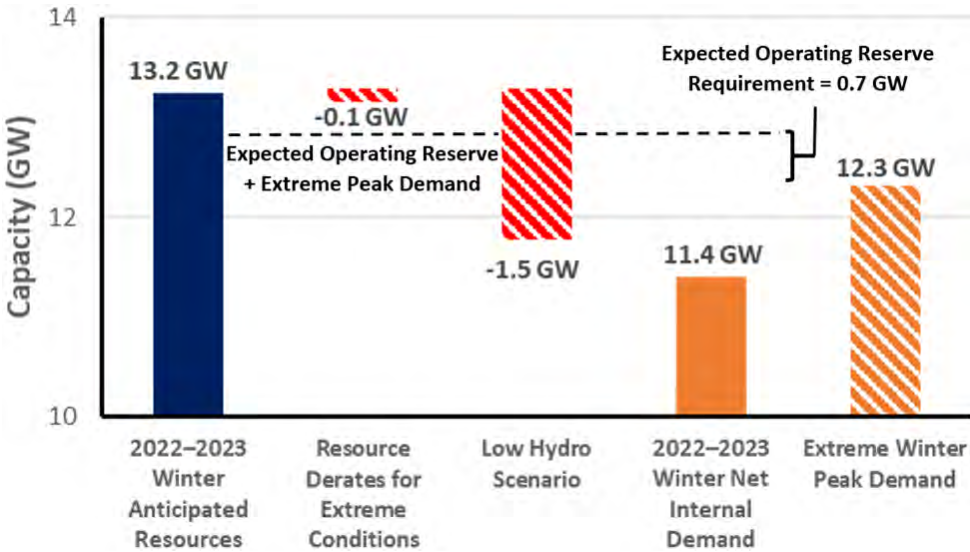
Risk Scenario Summary

Expected resources meet operating reserve requirements under normal peak-demand scenarios. Above-normal winter peak load and outage conditions combined with an unlikely low-hydro scenario could result in the need to employ operating mitigations (e.g., demand response, transfers, short-term load interruption) and EEAs.

On-Peak Reserve Margins



Risk-Period Scenario



Scenario Description (See [Data Concepts and Assumptions](#))

- Risk Period:** Highest risk for unserved energy at peak demand hour
- Demand Scenarios:** Net internal demand (50/50) and (90/10) demand forecast
- Extreme Derates:** Using (90/10) scenario
- Low Hydro Scenario:** Reduced hydro output due to drought conditions

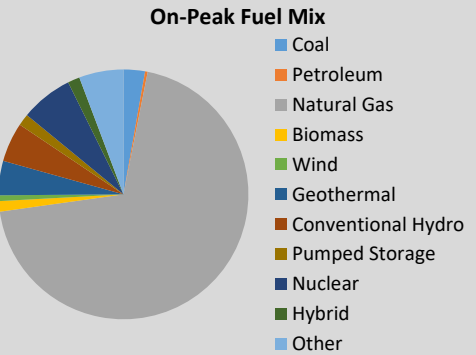


WECC-CA/MX

WECC-CA/MX (California/Mexico) is a summer-peaking assessment area in the WECC Regional Entity that includes parts of California, Nevada, and Baja California, Mexico.

WECC is responsible for coordinating and promoting BES reliability in the Western Interconnection. WECC’s 329 members include 39 Balancing Authorities, representing a wide spectrum of organizations with an interest in the BES. Serving an area of nearly 1.8 million square miles and more than 82 million customers, it is geographically the largest and most diverse Regional Entity.

WECC’s service territory extends from Canada to Mexico. It includes the provinces of Alberta and British Columbia in Canada, the northern portion of Baja California in Mexico as well as all or portions of the 14 Western United States in between.



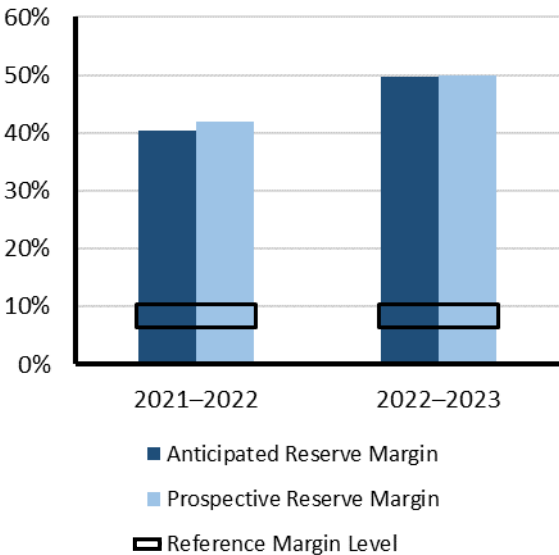
Highlight

- CA/MX is a summer-peaking area. Above average temperatures are forecasted for the upcoming winter. Operating reserve margins are met before imports in all winter resource availability scenarios.

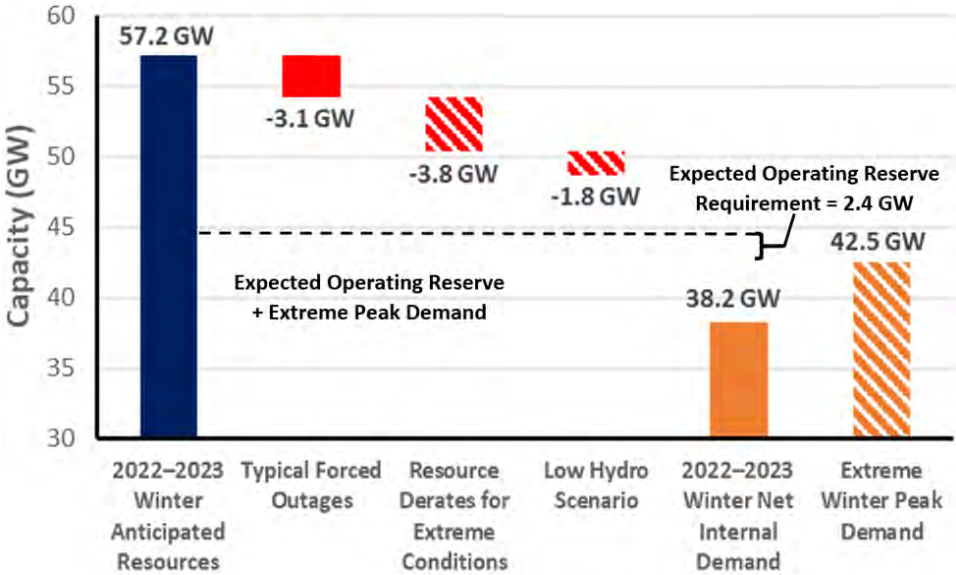
Risk Scenario Summary

Expected resources meet operating reserve requirements under assessed scenarios.

On-Peak Reserve Margins



Risk-Period Scenario



Scenario Description (See [Data Concepts and Assumptions](#))

- Risk Period:** Highest risk for unserved energy at peak demand hour
- Demand Scenarios:** Net internal demand (50/50) and (90/10) demand forecast
- Forced Outages:** Estimated using market forced outage model
- Extreme Derates:** On natural gas units based on historic data and manufacturer data for temperature performance and outages
- Low Hydro Scenario:** Reduced hydro output due to drought conditions



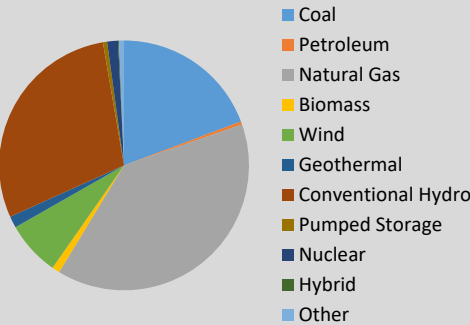
WECC-WPP

WECC-WPP (Western Power Pool) is a summer-peaking assessment area in the WECC Regional Entity. The area includes Colorado, Idaho, Montana, Oregon, Utah, Washington, Wyoming and parts of California, Nebraska, Nevada, and South Dakota.

WECC is responsible for coordinating and promoting BES reliability in the Western Interconnection. WECC’s 329 members include 39 Balancing Authorities, representing a wide spectrum of organizations with an interest in the BES. Serving an area of nearly 1.8 million square miles and more than 82 million customers, it is geographically the largest and most diverse Regional Entity.

WECC’s service territory extends from Canada to Mexico. It includes the provinces of Alberta and British Columbia in Canada, the northern portion of Baja California in Mexico as well as all or portions of the 14 Western United States in between.

On-Peak Fuel Mix



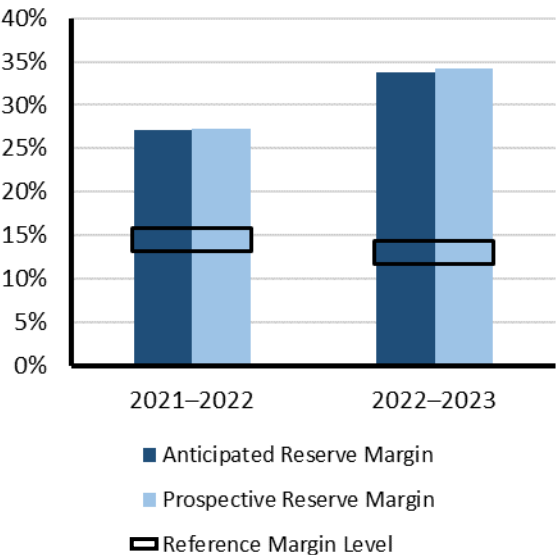
Highlight

- WPP has historically been a mixed season peaking area but is moving towards summer peaking. Operating reserve margins are met at the expected peak demand hour under all but the Extreme Combined scenario, where 1.6 GW of imports would be needed to meet operating reserve margins at an extreme peak demand.

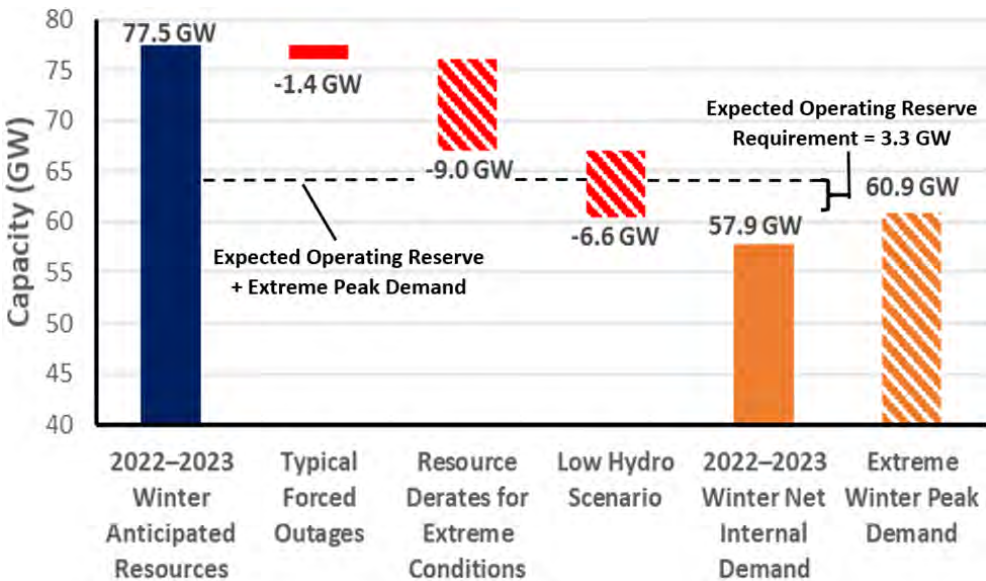
Risk Scenario Summary

Expected resources meet operating reserve requirements under normal and extreme peak-demand scenarios. Low hydro output is unlikely, but could result in the need to employ operating mitigations (i.e., demand response and transfers) and EEAs. The risk of load shedding is low due to the expected availability of transfers from neighboring areas.

On-Peak Reserve Margins



Risk-Period Scenario



Scenario Description (See [Data Concepts and Assumptions](#))

- Risk Period:** Highest risk for unserved energy at peak demand hour
- Demand Scenarios:** Net internal demand (50/50) and (90/10) demand forecast
- Forced Outages:** Average seasonal outages
- Extreme Derates:** Using (90/10) scenario
- Low Hydro Scenario:** Reduced hydro output due to drought conditions



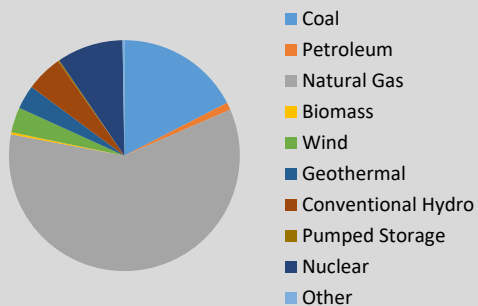
WECC-SRSG

WECC-SRSG (Southwest Reserve Sharing Group) is a summer-peaking assessment area in the WECC Regional Entity. It includes Arizona, New Mexico, and part of California and Texas.

WECC is responsible for coordinating and promoting BES reliability in the Western Interconnection. WECC's 329 members include 39 Balancing Authorities, representing a wide spectrum of organizations with an interest in the BES. Serving an area of nearly 1.8 million square miles and more than 82 million customers, it is geographically the largest and most diverse Regional Entity.

WECC's service territory extends from Canada to Mexico. It includes the provinces of Alberta and British Columbia in Canada as well as the northern portion of Baja California in Mexico and all or portions of the 14 Western United States in between.

On-Peak Fuel Mix



2022–2023 Winter Reliability Assessment

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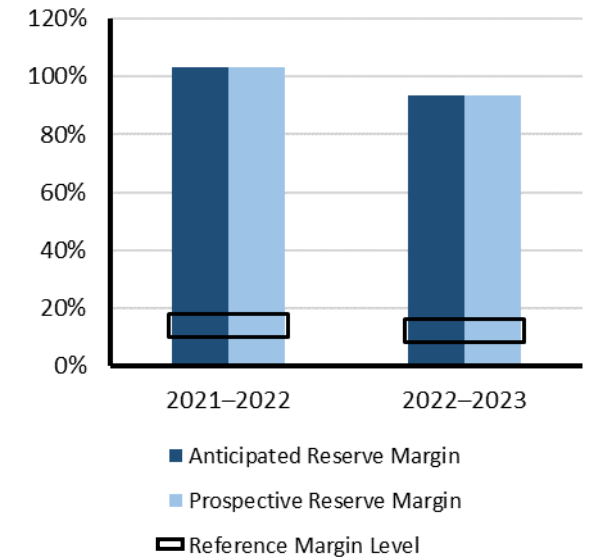
Highlight

- The summer peaking SRSR is expecting above average temperatures this winter. It is anticipated to be resource adequate under all winter extreme availability and demand scenarios. The higher margins compared to the summer season are due to a demand peak of 14 GW in the winter versus a peak of 26 GW in the summer.

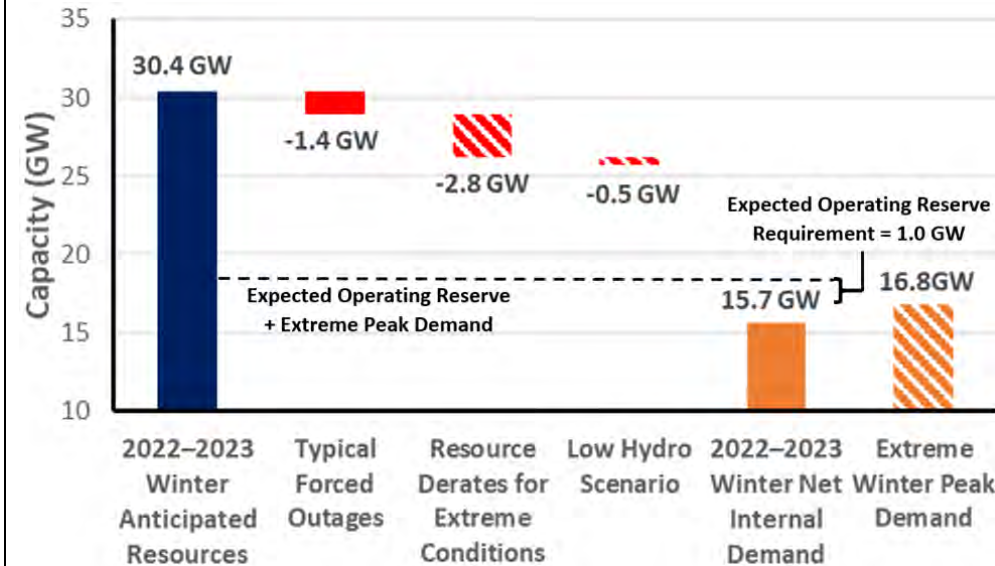
Risk Scenario Summary

Expected resources meet operating reserve requirements under assessed scenarios.

On-Peak Reserve Margins



Risk-Period Scenario



Scenario Description (See [Data Concepts and Assumptions](#))

Risk Period: Highest risk for unserved energy at peak demand hour

Demand Scenarios: Net internal demand (50/50) and (90/10) demand forecast

Forced Outages: Average seasonal outages

Extreme Derates: Using (90/10) scenario

Low Hydro Scenario: Reduced hydro output due to drought conditions

Data Concepts and Assumptions

The table below explains data concepts and important assumptions used throughout this assessment.

General Assumptions
- The reliability of the interconnected BPS is comprised of both adequacy and operating reliability: - Adequacy is the ability of the electricity system to supply the aggregate electric power and energy requirements of the electricity consumers at all times while taking into account scheduled and reasonably expected unscheduled outages of system components. - Operating reliability is the ability of the electricity system to withstand sudden disturbances such as electric short-circuits or unanticipated loss of system components. - The reserve margin calculation is an important industry planning metric used to examine future resource adequacy. - All data in this assessment is based on existing federal, state, and provincial laws and regulations. - Differences in data collection periods for each assessment area should be considered when comparing demand and capacity data between year-to-year seasonal assessments. 2022 Long-Term Reliability Assessment data has been used for most of this 2022–2023 assessment period augmented by updated load and capacity data. - A positive net transfer capability would indicate a net importing assessment area; a negative value would indicate a net exporter.
Demand Assumptions
- Electricity demand projections, or load forecasts, are provided by each assessment area. - Load forecasts include peak hourly load¹⁶ or total internal demand for the summer and winter of each year.¹⁷ - Total internal demand projections are based on normal weather (50/50 distribution¹⁸) and are provided on a coincident¹⁹ basis for most assessment areas. - Net internal demand is used in all reserve margin calculations, and it is equal to total internal demand then reduced by the amount of controllable and dispatchable demand response projected to be available during the peak hour.
Resource Assumptions
Resource planning methods vary throughout the North American BPS. NERC uses the categories below to provide a consistent approach for collecting and presenting resource adequacy. Because the electrical output of variable energy resources (e.g., wind, solar) depends on weather conditions, their contribution to reserve margins and other on-peak resource adequacy analysis is less than their nameplate capacity.

¹⁶ [Glossary of Terms](#) used in NERC Reliability Standards

¹⁷ The summer season represents June–September and the winter season represents December–February.

¹⁸ Essentially, this means that there is a 50% probability that actual demand will be higher and a 50% probability that actual demand will be lower than the value provided for a given season/year.

¹⁹ Coincident: This is the sum of two or more peak loads that occur in the same hour. Noncoincident: This is the sum of two or more peak loads on individual systems that do not occur in the same time interval; this is meaningful only when considering loads within a limited period of time, such as a day, a week, a month, a heating or cooling season, and usually for not more than one year. SERC and FRCC calculate total internal demand on a noncoincidental basis.

<u>Anticipated Resources:</u> • Existing-Certain Capacity: Included in this category are commercially operable generating unit or portions of generating units that meet at least one of the following requirements when examining the period of peak demand for the winter season: unit must have a firm capability and have a power purchase agreement with firm transmission that must be in effect for the unit; unit must be classified as a designated network resource; and/or where energy-only markets exist, unit must be a designated market resource eligible to bid into the market. • Tier 1 Capacity Additions: This category includes capacity that either is under construction or has received approved planning requirements. • Net Firm Capacity Transfers (Imports minus Exports): This category includes transfers with firm contracts.
<u>Prospective Resources:</u> Includes all anticipated resources plus the following: Existing-Other Capacity: Included in this category are commercially operable generating units or portions of generating units that could be available to serve load for the period of peak demand for the season but do not meet the requirements of existing-certain.
Reserve Margin Descriptions
Planning Reserve Margin: This is the primary metric used to measure resource adequacy; it is defined as the difference in resources (anticipated or prospective) and net internal demand then divided by net internal demand and shown as a percentage.
Reference Margin Level: The assumptions and naming convention of this metric vary by assessment area. The Reference Margin Level can be determined using both deterministic and probabilistic (based on a 0.1/year loss of load study) approaches. In both cases, this metric is used by system planners to quantify the amount of reserve capacity in the system above the forecasted peak demand that is needed to ensure sufficient supply to meet peak loads. Establishing a Reference Margin Level is necessary to account for long-term factors of uncertainty involved in system planning, such as unexpected generator outages and extreme weather impacts that could lead to increase demand beyond what was projected in the 50/50 load forecasted. In many assessment areas, a Reference Margin Level is established by a state, provincial authority, ISO/RTO, or other regulatory body. In some cases, the Reference Margin Level is a requirement. Reference Margin Levels may be different for the summer and winter seasons. If a Reference Margin Level is not provided by an assessment area, NERC applies 15% for predominately thermal systems and 10% for predominately hydro systems.
Seasonal Risk Scenario Chart Description
Each assessment area performed an operational risk analysis that was used to produce the seasonal risk scenario charts in the Regional Assessments Dashboards. The chart presents deterministic scenarios for further analysis of different resource and demand levels: The left blue column shows anticipated resources (from the resource adequacy data table), and the two orange columns at the right show the two demand scenarios of the normal peak net internal demand from the resource adequacy data table and the extreme winter peak demand—both determined by the assessment area. The middle red or green bars show adjustments that are applied cumulatively to the anticipated resources, such as the following: • Reductions for typical generation outages (i.e., maintenance and forced, not already accounted for in anticipated resources) • Reductions that represent additional outage or performance derating by resource type for extreme, low-probability conditions (e.g., drought condition impacts on hydroelectric generation, low-wind scenario affecting wind generation, fuel supply limitations, or extreme temperature conditions that result in reduced thermal generation output) • Additional capacity resources that represent quantified capacity from operational procedures, if any, that are made available during scarcity conditions Not all assessment areas have the same categories of adjustments to anticipated resources. Furthermore, each assessment area determined the adjustments to capacity based on methods or assumptions that are summarized below the chart. Methods and assumptions differ by assessment area and may not be comparable. The chart enables evaluation of resource levels against levels of expected operating reserve requirement and the forecasted demand. Further, the effects from extreme events can also be examined by comparing resource levels after applying extreme-scenario derates and/or extreme winter peak demand.

Resource Adequacy

The Anticipated Reserve Margin, which is based on available resource capacity, is a metric used to evaluate resource adequacy by comparing the projected capability of anticipated resources to serve forecast peak demand.²⁰ Large year-to-year changes in anticipated resources or forecast peak demand (net internal demand) can greatly impact Planning Reserve Margin calculations. Other than in NPCC-Maritimes, all assessment areas have sufficient Anticipated Reserve Margins to meet or exceed their Reference Margin Level for the 2022–2023 winter as shown in Figure 5. The Canadian winter-peaking systems of NPCC-Maritimes and NPCC-Québec have reserve margins that are near Reference Margin Levels but are unlikely to experience high outage rates from their winterized generators. The potential limited availability of locally stored fuel supplies could result in additional generator outages due to depleted fuel inventories. Variable energy resources, such as wind and solar, often contribute significantly less of their installed capability at the period of peak demand in winter. Winter peaks in many areas occur in early morning hours or other times of darkness, resulting in little or no electrical resource output. Consequently the capacity contribution of variable energy resources to an area’s anticipated resources may be a fraction of installed capability in winter.

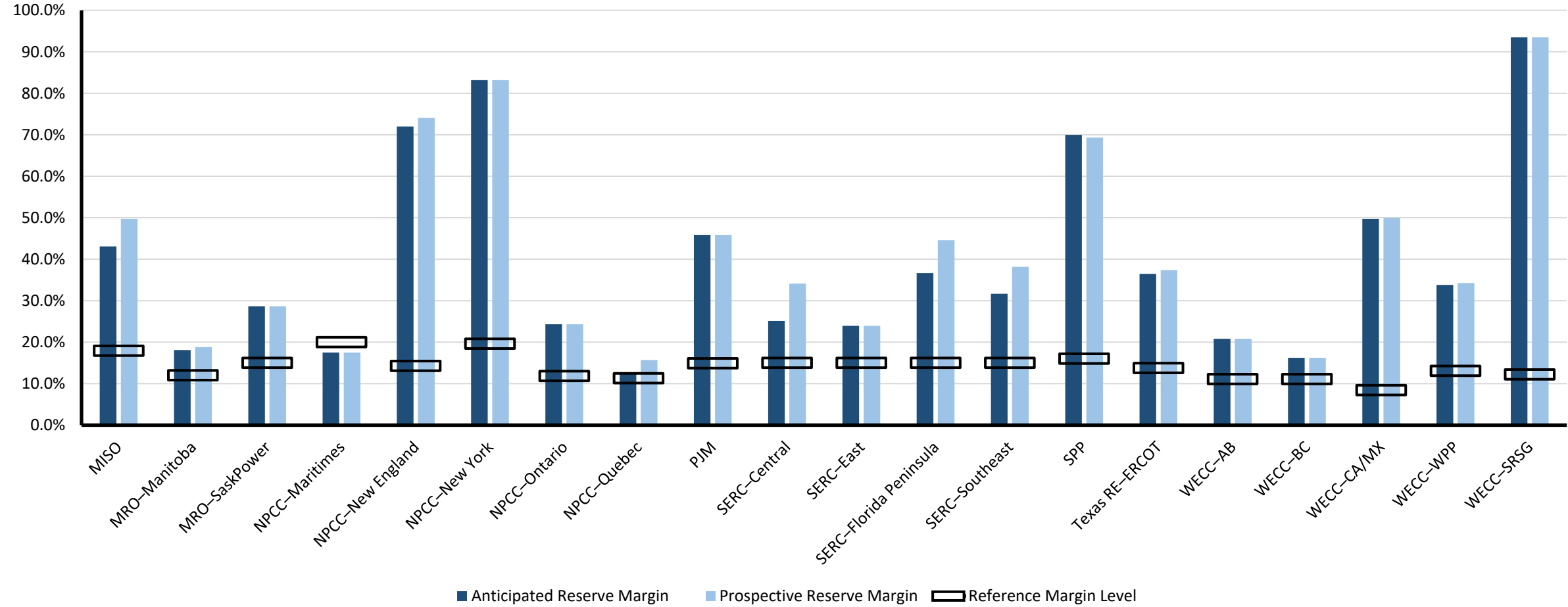


Figure 5: Winter 2022–2023 Anticipated/Prospective Reserve Margins Compared to Reference Margin Level

²⁰ Generally, anticipated resources include generators and firm capacity transfers that are expected to be available to serve load during electrical peak loads for the season. Prospective resources are those that could be available but do not meet criteria to be counted as anticipated resources. Refer to the [Data Concepts and Assumptions](#) section for additional information on Anticipated/Prospective Reserve Margins, anticipated/prospective resources, and Reference Margin Levels.

Changes from Year-to-Year

Figure 6 provides the relative change in the forecast Anticipated Reserve Margins from the 2021–2022 winter to the 2022–2023 winter. Note that the Reference Margin Level is unchanged for areas that don’t have a 2021–2022 Reference Margin Level shown. A significant decline can indicate potential operational issues that emerge between reporting years. MISO, NPCC-Maritimes, SERC-Central, SERC-Southeast, Texas RE-ERCOT, and WECC-AB have noticeable reductions in anticipated resources between the 2021–2022 winter and the 2022–2023 winter. All areas except NPCC-Maritimes remain above their Reference Margin Levels for 2022–2023 winter. The lower Anticipated Reserve Margins for MISO, SERC-Central, SERC-Southeast, Texas RE-ERCOT, and WECC-AB do not result in reliability concerns on peak for this upcoming winter. The Canadian winter peaking systems of NPCC-Maritimes and NPCC-Québec have reserve margins that are near Reference Margin Levels but are unlikely to experience high outage rates from their winterized generators. Additional details are provided in the [Data Concepts and Assumptions](#) section.

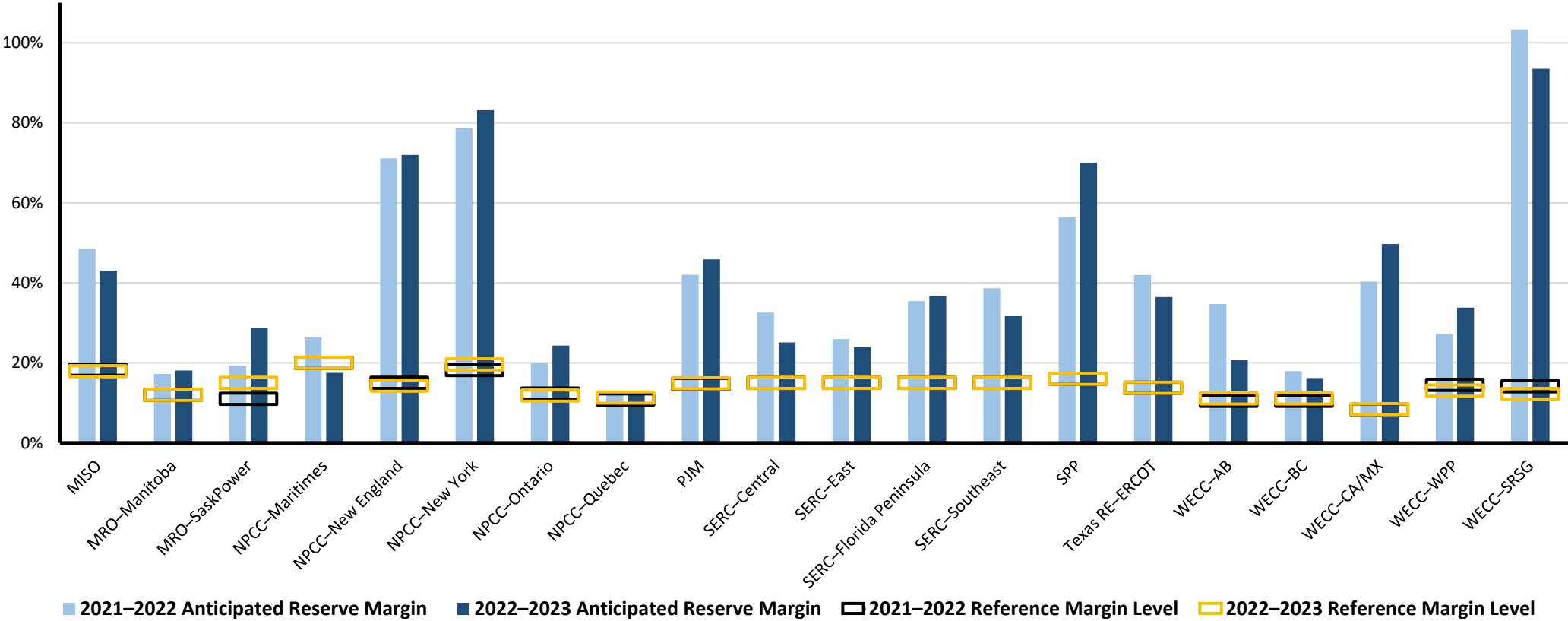


Figure 6: Winter 2021–2022 and Winter 2022–2023 Anticipated Reserve Margins Year-to-Year Change

Internal Demand

Winter peak demand forecasts in many assessment areas are increasing (see [Figure 7](#)). The aggregate of winter peak demand forecasts for all areas in the North American BPS has increased by 4,381 MW (0.6%) since the 2021–2022 winter. Since the 2019–2020 winter projections (made prior to the COVID-19 pandemic), the aggregate of demand forecasts for all of North America has increased by 2,766 MW, a 0.4% increase.

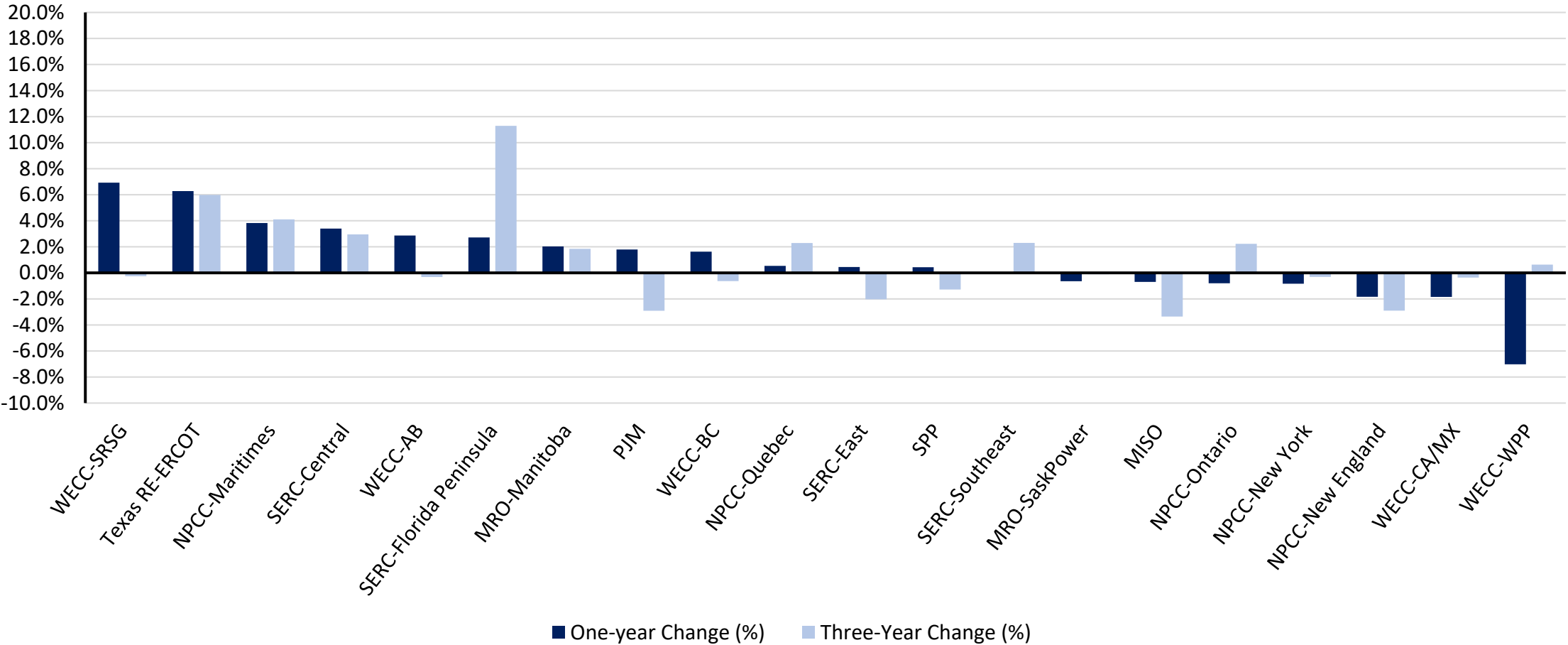


Figure 7: Change in Net Internal Demand: 2022–2023 Winter Forecast Compared To Prior Year Winter Forecasts

Demand and Resource Tables

Peak demand and supply capacity data for each assessment area are provided below (in alphabetical order).

MISO Resource Adequacy Data			
Demand, Resource, and Reserve Margins	2021–2022 WRA	2022–2023 WRA	2021–2022 vs. 2022–2023 WRA
Demand Projections	MW	MW	Net Change (%)
Total Internal Demand (50/50)	100,812	102,611	1.8%
Demand Response: Available	3,480	3,672	5.5%
Net Internal Demand	97,332	98,939	1.7%
Resource Projections	MW	MW	Net Change (%)
Existing-Certain Capacity	138,535	137,926	-0.4%
Tier 1 Planned Capacity	3,738	0	-100.0%
Net Firm Capacity Transfers	2,283	1,352	-40.8%
Anticipated Resources	144,556	141,565	-2.1%
Existing-Other Capacity	0	669	-
Prospective Resources	147,182	148,125	0.6%
Reserve Margins	Percent (%)	Percent (%)	Annual Difference
Anticipated Reserve Margin	48.5%	43.1%	-5.4
Prospective Reserve Margin	51.2%	49.7%	-1.5
Reference Margin Level	18.3%	17.9%	-0.4

MRO-Manitoba Hydro Adequacy Data			
Demand, Resource, and Reserve Margins	2021–2022 WRA	2022–2023 WRA	2021–2022 vs. 2022–2023 WRA
Demand Projections	MW	MW	Net Change (%)
Total Internal Demand (50/50)	4,497	4,588	2.0%
Demand Response: Available	0	0	-
Net Internal Demand	4,497	4,588	2.0%
Resource Projections	MW	MW	Net Change (%)
Existing-Certain Capacity	5,438	5,705	4.9%
Tier 1 Planned Capacity	279	279	0.1%
Net Firm Capacity Transfers	-446	-566	26.9%
Anticipated Resources	5,271	5,418	2.8%
Existing-Other Capacity	46	33	-29.4%
Prospective Resources	5,318	5,451	2.5%
Reserve Margins	Percent (%)	Percent (%)	Annual Difference
Anticipated Reserve Margin	17.2%	18.1%	0.9
Prospective Reserve Margin	18.3%	18.8%	0.5
Reference Margin Level	12.0%	12.0%	0.0

MRO-SaskPower Resource Adequacy Data			
Demand, Resource, and Reserve Margins	2021–2022 WRA	2022–2023 WRA	2021–2022 vs. 2022–2023 WRA
Demand Projections	MW	MW	Net Change (%)
Total Internal Demand (50/50)	3,798	3,781	-0.4%
Demand Response: Available	60	67	11.7%
Net Internal Demand	3,738	3,714	-0.6%
Resource Projections	MW	MW	Net Change (%)
Existing-Certain Capacity	4,321	4,488	3.9%
Tier 1 Planned Capacity	13	0	-100.0%
Net Firm Capacity Transfers	125	290	132.0%
Anticipated Resources	4,459	4,778	7.2%
Existing-Other Capacity	0	0	-
Prospective Resources	4,459	4,778	7.2%
Reserve Margins	Percent (%)	Percent (%)	Annual Difference
Anticipated Reserve Margin	19.3%	28.7%	9.4
Prospective Reserve Margin	19.3%	28.7%	9.4
Reference Margin Level	11.0%	15.0%	4.0

NPCC-Maritimes Resource Adequacy Data			
Demand, Resource, and Reserve Margins	2021–2022 WRA	2022–2023 WRA	2021–2022 vs. 2022–2023 WRA
Demand Projections	MW	MW	Net Change (%)
Total Internal Demand (50/50)	5,616	5,784	3.0%
Demand Response: Available	317	282	-11.0%
Net Internal Demand	5,299	5,502	3.8%
Resource Projections	MW	MW	Net Change (%)
Existing-Certain Capacity	6,584	6,461	-1.9%
Tier 1 Planned Capacity	0	0	-
Net Firm Capacity Transfers	121	4	-96.7%
Anticipated Resources	6,705	6,465	-3.6%
Existing-Other Capacity	0	0	-
Prospective Resources	6,705	6,465	-3.6%
Reserve Margins	Percent (%)	Percent (%)	Annual Difference
Anticipated Reserve Margin	26.5%	17.5%	-9.0
Prospective Reserve Margin	26.5%	17.5%	-9.0
Reference Margin Level	20.0%	20.0%	0.0%

NPCC-New England Resource Adequacy Data			
Demand, Resource, and Reserve Margins	2021–2022 WRA	2022–2023 WRA	2021–2022 vs. 2022–2023 WRA
Demand Projections	MW	MW	Net Change (%)
Total Internal Demand (50/50)	20,349	20,009	-1.7%
Demand Response: Available	587	610	4.0%
Net Internal Demand	19,762	19,399	-1.8%
Resource Projections	MW	MW	Net Change (%)
Existing-Certain Capacity	32,668	32,129	-1.6%
Tier 1 Planned Capacity	14	162	1057.0%
Net Firm Capacity Transfers	1,134	1,070	-5.6%
Anticipated Resources	33,816	33,361	-1.3%
Existing-Other Capacity	184	142	-23.0%
Prospective Resources	34,000	33,769	-0.7%
Reserve Margins	Percent (%)	Percent (%)	Annual Difference
Anticipated Reserve Margin	71.1%	72.0%	0.9
Prospective Reserve Margin	72.0%	74.1%	2.1
Reference Margin Level	15.0%	14.3%	-0.7

NPCC-New York Resource Adequacy Data			
Demand, Resource, and Reserve Margins	2021–2022 WRA	2022–2023 WRA	2021–2022 vs. 2022–2023 WRA
Demand Projections	MW	MW	Net Change (%)
Total Internal Demand (50/50)	24,025	23,893	-0.5%
Demand Response: Available	631	695	10.1%
Net Internal Demand	23,394	23,198	-0.8%
Resource Projections	MW	MW	Net Change (%)
Existing-Certain Capacity	40,239	40,393	0.4%
Tier 1 Planned Capacity	0	0	-
Net Firm Capacity Transfers	1,547	2,097	35.6%
Anticipated Resources	41,786	42,490	1.7%
Existing-Other Capacity	0	0	-
Prospective Resources	41,786	42,490	1.7%
Reserve Margins	Percent (%)	Percent (%)	Annual Difference
Anticipated Reserve Margin	78.6%	83.2%	4.6
Prospective Reserve Margin	78.6%	83.2%	4.6
Reference Margin Level	18.2%	19.6%	1.4

NPCC-Ontario Resource Adequacy Data			
Demand, Resource, and Reserve Margins	2021–2022 WRA	2022–2023 WRA	2021–2022 vs. 2022–2023 WRA
Demand Projections	MW	MW	Net Change (%)
Total Internal Demand (50/50)	20,940	21,255	1.5%
Demand Response: Available	132	614	364.1%
Net Internal Demand	20,808	20,641	-0.8%
Resource Projections	MW	MW	Net Change (%)
Existing-Certain Capacity	25,403	26,051	2.6%
Tier 1 Planned Capacity	63	112	77.0%
Net Firm Capacity Transfers	-500	-500	0.0%
Anticipated Resources	24,966	25,662	2.8%
Existing-Other Capacity	0	0	-
Prospective Resources	24,966	25,662	2.8%
Reserve Margins	Percent (%)	Percent (%)	Annual Difference
Anticipated Reserve Margin	20.0%	24.3%	4.3
Prospective Reserve Margin	20.0%	24.3%	4.3
Reference Margin Level	12.3%	11.8%	-0.5

NPCC-Québec Resource Adequacy Data			
Demand, Resource, and Reserve Margins	2021–2022 WRA	2022–2023 WRA	2021–2022 vs. 2022–2023 WRA
Demand Projections	MW	MW	Net Change (%)
Total Internal Demand (50/50)	39,386	39,699	0.8%
Demand Response: Available	2,368	2,759	16.5%
Net Internal Demand	37,017	37,217	0.5%
Resource Projections	MW	MW	Net Change (%)
Existing-Certain Capacity	42,072	42,113	0.1%
Tier 1 Planned Capacity	27	255	838.2%
Net Firm Capacity Transfers	-499	-417	-16.4%
Anticipated Resources	41,600	41,951	0.8%
Existing-Other Capacity	0	0	-
Prospective Resources	42,700	43,051	0.8%
Reserve Margins	Percent (%)	Percent (%)	Annual Difference
Anticipated Reserve Margin	12.4%	12.7%	0.3%
Prospective Reserve Margin	15.4%	15.7%	0.3%
Reference Margin Level	10.8%	11.3%	0.5%

PJM Resource Adequacy Data			
Demand, Resource, and Reserve Margins	2021–2022 WRA	2022–2023 WRA	2021–2022 vs. 2022–2023 WRA
Demand Projections	MW	MW	Net Change (%)
Total Internal Demand (50/50)	132,632	132,980	0.3%
Demand Response: Available	8,466	6,583	-22.2%
Net Internal Demand	124,166	126,397	1.8%
Resource Projections	MW	MW	Net Change (%)
Existing-Certain Capacity	179,247	185,102	3.3%
Tier 1 Planned Capacity	19	0	-100.0%
Net Firm Capacity Transfers	-2,937	-726	-75.3%
Anticipated Resources	176,329	184,376	4.6%
Existing-Other Capacity	0	0	-
Prospective Resources	176,329	184,376	4.6%
Reserve Margins	Percent (%)	Percent (%)	Annual Difference
Anticipated Reserve Margin	42.0%	45.9%	-3.9
Prospective Reserve Margin	42.0%	45.9%	-3.9
Reference Margin Level	14.7%	14.9%	-0.2

SERC-Central Resource Adequacy Data			
Demand, Resource, and Reserve Margins	2021–2022 WRA	2022–2023 WRA	2021–2022 vs. 2022–2023 WRA
Demand Projections	MW	MW	Net Change (%)
Total Internal Demand (50/50)	40,320	41,745	3.5%
Demand Response: Available	1,564	1,671	6.8%
Net Internal Demand	38,756	40,074	3.4%
Resource Projections	MW	MW	Net Change (%)
Existing-Certain Capacity	51,271	51,008	-0.5%
Tier 1 Planned Capacity	0	0	-
Net Firm Capacity Transfers	99	-868	-
Anticipated Resources	51,370	50,140	-2.4%
Existing-Other Capacity	3,135	3,601	14.9%
Prospective Resources	54,505	53,741	-1.4%
Reserve Margins	Percent (%)	Percent (%)	Annual Difference
Anticipated Reserve Margin	32.5%	25.1%	-7.4
Prospective Reserve Margin	40.6%	34.1%	-6.5
Reference Margin Level	15.0%	15.0%	0.0

SERC-East Resource Adequacy Data			
Demand, Resource, and Reserve Margins	2021–2022 WRA	2022–2023 WRA	2021–2022 vs. 2022–2023 WRA
Demand Projections	MW	MW	Net Change (%)
Total Internal Demand (50/50)	44,175	44,648	1.1%
Demand Response: Available	903	1,180	30.7%
Net Internal Demand	43,272	43,468	0.5%
Resource Projections	MW	MW	Net Change (%)
Existing-Certain Capacity	53,933	53,287	-1.2%
Tier 1 Planned Capacity	0	75	-
Net Firm Capacity Transfers	562	513	-8.7%
Anticipated Resources	54,495	53,875	-1.1%
Existing-Other Capacity	0	3	-
Prospective Resources	54,495	53,877	-1.1%
Reserve Margins	Percent (%)	Percent (%)	Annual Difference
Anticipated Reserve Margin	25.9%	23.9%	-2.0
Prospective Reserve Margin	25.9%	23.9%	-2.0
Reference Margin Level	15.0%	15.0%	0.0

SERC-Florida Peninsula Resource Adequacy Data			
Demand, Resource, and Reserve Margins	2021–2022 WRA	2022–2023 WRA	2021–2022 vs. 2022–2023 WRA
Demand Projections	MW	MW	Net Change (%)
Total Internal Demand (50/50)	46,074	48,582	5.4%
Demand Response: Available	1,571	2,870	82.7%
Net Internal Demand	44,503	45,712	2.7%
Resource Projections	MW	MW	Net Change (%)
Existing-Certain Capacity	57,694	61,987	7.4%
Tier 1 Planned Capacity	1,169	237	-79.7%
Net Firm Capacity Transfers	1,414	250	-82.3%
Anticipated Resources	60,277	62,474	3.6%
Existing-Other Capacity	1,147	3,618	215.5%
Prospective Resources	61,424	66,092	7.6%
Reserve Margins	Percent (%)	Percent (%)	Annual Difference
Anticipated Reserve Margin	35.4%	36.7%	1.3
Prospective Reserve Margin	38.0%	44.6%	6.6
Reference Margin Level	15.0%	15.0%	0.0

SERC-Southeast Resource Adequacy Data			
Demand, Resource, and Reserve Margins	2021–2022 WRA	2022–2023 WRA	2021–2022 vs. 2022–2023 WRA
Demand Projections	MW	MW	Net Change (%)
Total Internal Demand (50/50)	46,232	46,513	0.6%
Demand Response: Available	1,682	1,954	16.2%
Net Internal Demand	44,550	44,559	0.0%
Resource Projections	MW	MW	Net Change (%)
Existing-Certain Capacity	61,899	60,097	-2.9%
Tier 1 Planned Capacity	1,102	1,102	0.0%
Net Firm Capacity Transfers	-1,218	-2,524	107.2%
Anticipated Resources	61,782	58,674	-5.0%
Existing-Other Capacity	2,516	2,895	15.1%
Prospective Resources	64,298	61,569	-4.2%
Reserve Margins	Percent (%)	Percent (%)	Annual Difference
Anticipated Reserve Margin	38.7%	31.7%	-7.0
Prospective Reserve Margin	44.3%	38.2%	-6.1
Reference Margin Level	15.0%	15.0%	0.0

Texas RE-ERCOT Resource Adequacy Data			
Demand, Resource, and Reserve Margins	2021–2022 WRA	2022–2023 WRA	2021–2022 vs. 2022–2023 WRA
Demand Projections	MW	MW	Net Change (%)
Total Internal Demand (50/50)	62,001	66,436	7.2%
Demand Response: Available	2,598	3,302	27.1%
Net Internal Demand	59,403	63,134	6.3%
Resource Projections	MW	MW	Net Change (%)
Existing-Certain Capacity	81,443	85,478	5.0%
Tier 1 Planned Capacity	2,665	644	-75.8%
Net Firm Capacity Transfers	210	20	-90.5%
Anticipated Resources	84,318	86,142	2.2%
Existing-Other Capacity	0	0	-
Prospective Resources	84,382	86,710	2.8%
Reserve Margins	Percent (%)	Percent (%)	Annual Difference
Anticipated Reserve Margin	41.9%	36.4%	-5.5
Prospective Reserve Margin	42.1%	37.3%	-4.8
Reference Margin Level	13.75%	13.75%	0.0

SPP Resource Adequacy Data			
Demand, Resource, and Reserve Margins	2021–2022 WRA	2022–2023 WRA	2021–2022 vs. 2022–2023 WRA
Demand Projections	MW	MW	Net Change (%)
Total Internal Demand (50/50)	41,669	41,650	0.0%
Demand Response: Available	211	13	-93.7%
Net Internal Demand	41,458	41,637	0.4%
Resource Projections	MW	MW	Net Change (%)
Existing-Certain Capacity	65,197	71,131	9.1%
Tier 1 Planned Capacity	0	0	-
Net Firm Capacity Transfers	-348	-359	3.3%
Anticipated Resources	64,850	70,772	9.1%
Existing-Other Capacity	0	0	-
Prospective Resources	64,820	70,496	8.8%
Reserve Margins	Percent (%)	Percent (%)	Annual Difference
Anticipated Reserve Margin	56.4%	70.0%	13.6%
Prospective Reserve Margin	56.4%	69.3%	13.0%
Reference Margin Level	16.0%	16.0%	0.0

WECC-AB Resource Adequacy Data			
Demand, Resource, and Reserve Margins	2021–2022 WRA	2022–2023 WRA	2021–2022 vs. 2022–2023 WRA
Demand Projections	MW	MW	Net Change (%)
Total Internal Demand (50/50)	11,569	11,901	2.9%
Demand Response: Available	0	0	-
Net Internal Demand	11,569	11,901	2.9%
Resource Projections	MW	MW	Net Change (%)
Existing-Certain Capacity	12,842	13,144	2.3%
Tier 1 Planned Capacity	2,743	1,234	-55.0%
Net Firm Capacity Transfers	0	0	-
Anticipated Resources	15,585	14,378	-7.7%
Existing-Other Capacity	0	0	-
Prospective Resources	15,585	14,378	-7.7%
Reserve Margins	Percent (%)	Percent (%)	Annual Difference
Anticipated Reserve Margin	34.7%	20.8%	-13.9
Prospective Reserve Margin	34.7%	20.8%	-13.9
Reference Margin Level	10.5%	11.1%	0.6

WECC-BC Resource Adequacy Data			
Demand, Resource, and Reserve Margins	2021–2022 WRA	2022–2023 WRA	2021–2022 vs. 2022–2023 WRA
Demand Projections	MW	MW	Net Change (%)
Total Internal Demand (50/50)	11,213	11,395	1.6%
Demand Response: Available	0	0	-
Net Internal Demand	11,213	11,395	1.6%
Resource Projections	MW	MW	Net Change (%)
Existing-Certain Capacity	13,077	13,223	1.1%
Tier 1 Planned Capacity	146	20	-86.4%
Net Firm Capacity Transfers	0	0	-
Anticipated Resources	13,223	13,243	0.1%
Existing-Other Capacity	0	0	-
Prospective Resources	13,223	13,243	0.1%
Reserve Margins	Percent (%)	Percent (%)	Annual Difference
Anticipated Reserve Margin	17.9%	16.2%	-1.7
Prospective Reserve Margin	17.9%	16.2%	-1.7
Reference Margin Level	10.5%	11.1%	0.6

WECC-SRSG Resource Adequacy Data			
Demand, Resource, and Reserve Margins	2021–2022 WRA	2022–2023 WRA	2021–2022 vs. 2022–2023 WRA
Demand Projections	MW	MW	Net Change (%)
Total Internal Demand (50/50)	14,910	16,004	7.3%
Demand Response: Available	241	318	32.3%
Net Internal Demand	14,669	15,686	6.9%
Resource Projections	MW	MW	Net Change (%)
Existing-Certain Capacity	29,446	29,799	1.2%
Tier 1 Planned Capacity	381	553	45.1%
Net Firm Capacity Transfers	0	0	-
Anticipated Resources	29,827	30,352	1.8%
Existing-Other Capacity	0	0	-
Prospective Resources	29,836	30,352	1.7%
Reserve Margins	Percent (%)	Percent (%)	Annual Difference
Anticipated Reserve Margin	103.3%	93.5%	-9.8
Prospective Reserve Margin	103.4%	93.5%	-9.9
Reference Margin Level	14.1%	12.2%	-1.9

WECC-CA/MX Resource Adequacy Data			
Demand, Resource, and Reserve Margins	2021–2022 WRA	2022–2023 WRA	2021–2022 vs. 2022–2023 WRA
Demand Projections	MW	MW	Net Change (%)
Total Internal Demand (50/50)	39,779	38,978	-2.0%
Demand Response: Available	829	749	-9.7%
Net Internal Demand	38,950	38,230	-1.8%
Resource Projections	MW	MW	Net Change (%)
Existing-Certain Capacity	51,996	55,287	6.3%
Tier 1 Planned Capacity	2,205	1,943	-11.9%
Net Firm Capacity Transfers	449	0	-100.0%
Anticipated Resources	54,650	57,231	4.7%
Existing-Other Capacity	0	0	-
Prospective Resources	55,312	57,326	3.6%
Reserve Margins	Percent (%)	Percent (%)	Annual Difference
Anticipated Reserve Margin	40.3%	49.7%	9.4
Prospective Reserve Margin	42.0%	50.0%	8.0
Reference Margin Level	8.3%	8.4%	0.1

WECC-WPP Resource Adequacy Data			
Demand, Resource, and Reserve Margins	2021–2022 WRA	2022–2023 WRA	2021–2022 vs. 2022–2023 WRA
Demand Projections	MW	MW	Net Change (%)
Total Internal Demand (50/50)	62,822	58,605	-6.7%
Demand Response: Available	551	707	28.4%
Net Internal Demand	62,271	57,898	-7.0%
Resource Projections	MW	MW	Net Change (%)
Existing-Certain Capacity	74,865	76,477	2.2%
Tier 1 Planned Capacity	424	988	133.1%
Net Firm Capacity Transfers	3,877	0	-100.0%
Anticipated Resources	79,166	77,465	-2.1%
Existing-Other Capacity	0	0	-
Prospective Resources	79,205	77,730	-1.9%
Reserve Margins	Percent (%)	Percent (%)	Annual Difference
Anticipated Reserve Margin	27.1%	33.8%	6.7
Prospective Reserve Margin	27.2%	34.3%	7.1
Reference Margin Level	14.5%	13.1%	-1.4

Errata

November 2022

- The Extreme Conditions reserve margin for SERC-FP in Table 1 was corrected (page 8)
- The Scenario Description language in Texas RE-ERCOT’s dashboard was corrected (page 26)

NERC

NORTH AMERICAN ELECTRIC
RELIABILITY CORPORATION

2023–2024 Winter Reliability Assessment

November 2023

[WRA Infographic](#) | [WRA Video](#)



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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 NERC and the six Regional Entities, is a highly reliable, resilient, 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 Regional Entity as shown in the map and corresponding table below. The multicolored area denotes overlap as some load-serving entities participate in one Regional Entity 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

About this Assessment

NERC's *2023–2024 Winter Reliability Assessment (WRA)* identifies, assesses, and reports on areas of concern regarding the reliability of the North American BPS for the upcoming winter season. In addition, the *WRA* presents peak electricity demand and supply changes and highlights any unique regional challenges or expected conditions that might affect the reliability of the BPS.

This reliability assessment process is a coordinated evaluation between the Reliability Assessment Subcommittee, the Regional Entities, and NERC staff with demand and resource projections obtained from the assessment areas.

This report reflects an independent assessment by the ERO Enterprise (i.e., NERC and the six Regional Entities) and is intended to inform industry leaders, planners, operators, and regulatory bodies so that they are better prepared to take necessary actions to ensure BPS reliability. This report also provides an opportunity for the industry to discuss plans and preparations to ensure reliability for the upcoming winter period.

Key Findings

This *WRA* covers the upcoming three-month (December–February) winter period. This assessment provides an evaluation of the generation resource and transmission system adequacy necessary to meet projected winter peak demands and operating reserves. This assessment identifies potential reliability issues of interest and regional risks. The following findings are the ERO Enterprise’s independent evaluation of electricity generation and transmission capacity as well as the potential operational concerns that may need to be addressed for the upcoming winter:

- 1. **A large portion of the North American BPS is at risk of insufficient electricity supplies during peak winter conditions (Figure 1).** Prolonged, wide-area cold snaps threaten the reliable performance of BPS generation and the availability of fuel supplies for natural-gas-fired generation. As observed in recent winter reliability events, over 20% of generating capacity has been forced off-line when freezing temperatures extend over parts of North America that are not typically exposed to such conditions. When electricity supplies become constrained, BPS system operators can face a simultaneous sharp increase in demand as electric heating systems consume more power in cold temperatures. These areas (see Figure 1) are at greatest risk for electricity supply shortfalls this winter:
 - **Midcontinent ISO (MISO):** New wind and natural-gas-fired generation and the extension of some older fossil-fired plants have increased available resources this winter by over 9 GW from 2022. Recently, MISO implemented a seasonal resource adequacy construct that more effectively values risks and resource contributions that vary by time of year. Like prior years, an extreme cold-weather event that extends into MISO’s southern areas can cause high generator outages from inadequate weatherization or insufficient natural gas fuel supplies.
 - **MRO-SaskPower:** Reserve margins have fallen this winter by eight percentage points when compared to the previous winter due to increased peak demand projections, the retirement of a natural-gas-fired unit (95 MW), and planned generator maintenance. High numbers of forced generator outages or wind turbine cold temperature cutouts can lead to operating reserves shortfalls at peak winter demand levels.
 - **NPCC-Maritimes:** Peak demand growth has been offset by additional resource capacity and import agreements for the upcoming winter, causing reserve margins to rise by over two percentage points compared to 2022. Demand levels at the forecasted peak can still strain the area’s firm supplies and lead to operating mitigations or energy emergencies.

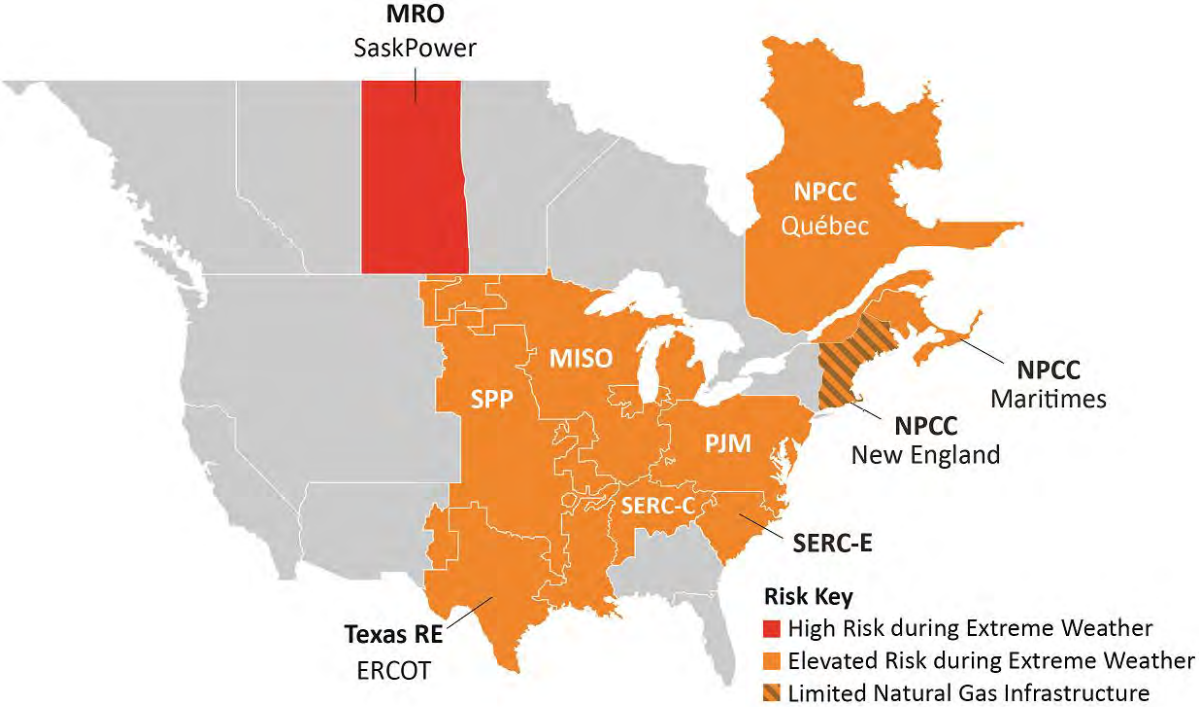


Figure 1: Winter Reliability Risk Area Summary

Seasonal Risk Assessment Summary	
High	Potential for insufficient operating reserves in normal peak conditions
Elevated	Potential for insufficient operating reserves in above-normal conditions
Low	Sufficient operating reserves expected

- **NPCC-New England:** The capacity of natural gas transportation infrastructure could be constrained when cold temperatures cause peak demand for both electricity generation and consumer space-heating needs. Potential constraints on the fuel delivery systems and the limited inventory of liquid fuels may exacerbate the risks for fuel-based generator outages and output reductions that result in energy emergencies during extreme weather. ISO-New England (ISO-NE) introduced the Inventoried Energy Program this year as an interim measure to address energy security concerns. The program provides compensation for generators that maintain inventoried energy for their assets during extreme cold periods. The program is also planned for 2024–2025 winter while ISO-NE develops more comprehensive energy security measures for regulatory approval.

- **NPCC-Québec:** An increase in forecasted peak demand and additional firm export commitments have resulted in lower reserve margins for the upcoming winter. Despite having reliable performance from hydroelectric generation in winter, non-firm imports may be needed to meet operating reserve requirements if demand levels exceed the forecasted peak.
 - **PJM, SERC-East, and SERC-Central:** A severe cold weather event that extends to the Southern United States can lead to energy emergencies as operators face sharp increases in generator forced outages and electricity demand. Forecasted peak demand has risen while resources have changed little in these areas since Winter Storm Elliot caused energy emergencies across the area in 2022. PJM and SERC have adequate resources for normal winter conditions; however, their generators are vulnerable to derates and outages in extreme conditions.
 - **Southwest Power Pool (SPP):** The Anticipated Reserve Margin (ARM) of 38.8% is over 30 percentage points lower than last winter; this is driven by higher forecasted peak demand and less resource capacity. While the reserve margin is adequate for normal forecasted peak demand and expected generator outages, higher demand levels and outages that have occurred during extreme cold weather result in shortfalls that can trigger energy emergencies. The vast wind resources in the area can alleviate firm capacity shortages under the right conditions; however, energy risks emerge during periods of low wind or forecast uncertainty and high electricity demand.
 - **Texas RE-ERCOT:** Like other assessment areas in the Southern United States, the risk of a significant number of generator forced outages in extreme and prolonged cold temperatures continues to threaten reliability where generators and fuel supply infrastructure are not designed or retrofitted for such conditions. The risk of reserve shortage is greater than last winter due primarily to robust load growth that is not being met by corresponding growth in dispatchable resources. ERCOT is taking steps to procure additional capacity ahead of winter that can reduce the likelihood of energy emergencies. Additionally, ERCOT implemented a new firm fuel supply service in its market that is expected to partially offset the lost generation capacity that can occur when natural gas supplies are limited. Electricity demand in Texas rises sharply as extreme cold temperatures add to winter operating challenges and energy shortfall risks.
- 2. Generator fuel supplies remain at risk during extreme, long-duration cold weather events.** Fuel assurance is vitally important to meeting winter electricity demand across North America. Natural-gas-fired generator availability and output can be threatened when natural

gas supplies are insufficient or when the flow of fuel cannot be maintained. During Winter Storm Elliott, natural gas production rapidly declined with the onset of extreme cold temperatures, contributing to wide-area electricity and natural gas shortages.

Currently, natural gas production, transportation, storage, and a significant portion of the BPS link together to form a single interconnected energy delivery system that extends from the natural gas wellhead to end-use electricity and natural gas customers. The operation of this interconnected energy system can be disrupted when natural gas fuel supplies are not available for electricity generation as well as when electricity is not available to operate electricity-driven compressors and other critical infrastructure components in the natural gas supply chain. Recent extreme cold weather events have shown that energy delivery disruptions can have devastating consequences for electric and natural gas consumers in impacted areas.

Winter Storm Elliott demonstrated the wide-area consequences for BPS reliability that can result from reduced natural gas production during periods of extreme cold weather. In addition to wellhead impacts on production, natural-gas-fired generating units that lacked firm supply or transportation contracts to meet their winter peak electrical output faced challenging and often insurmountable fuel procurement issues when natural gas supply and available pipeline capacity became scarce. During Winter Storm Elliott, natural-gas-related fuel outages occurred alongside generator outages, derates, and failures to start that resulted from freezing issues and mechanical/electrical issues that are closely correlated with falling temperatures.

The joint *FERC-NERC-Regional Entity Joint Inquiry into Winter Storm Elliott* made the following recommendations related to adequate fuel supply assurance and other matters:¹

- Establishing reliability rules for natural gas infrastructure
- Improving communication and business practices between industries
- Assessing Balancing Authority (BA) reliability commitment processes for addressing potential capacity shortages during forecasted cold weather events

To enhance situational awareness across impacted interconnected energy delivery systems, the FERC-NERC report also included a more immediate recommendation that BPS operators and natural gas industry controllers convene to establish control room to control room operational communications protocols that can be invoked when extreme cold weather approaches and that these protocols remain in place over the duration of the event.

¹ [FERC Winter Storm Elliott Report](#)

Coal is also an important fuel for electricity generation in winter. Generator owners report fewer coal supply issues compared to last winter. Normal rail transportation services are available and coal stocks are at a high level compared to historical averages. Some coal fired generation that relies on barge shipments in inland waterways could be impacted by drought restrictions that limit barge loading.

3. **Load forecasting in winter is growing in complexity. Underestimating demand is a risk to reliability in extreme cold temperatures.** Extreme cold temperatures and irregular weather patterns characterized by strong cold fronts, wind, and precipitation can cause demand for electricity to deviate significantly from historical forecasts. Electrification of the heating sector is increasing temperature-sensitive load components while increasing levels of variable-output solar photovoltaic (PV) distributed energy resources (DER) add to the load forecast uncertainty. Underestimating electricity demand prior to the arrival of cold temperatures can lead to ineffective operations planning and insufficient resources being scheduled. Generator performance and fuel issues are more likely to occur when generators are called upon with short notice; this can expose BAs to potential resource shortfalls. Load serving entities and BAs should apply lessons from prior winter operating experience to operational load forecasts and pay particular attention to the risk of demand underestimation ahead of extreme winter conditions.
4. **Curtailed of electricity transfers to areas in need during periods of high regional demand is a growing reliability concern.** During energy emergencies and periods of transmission system congestion, Reliability Coordinators (RC) and BAs may curtail transfers for various reasons with established procedures and protocols. While the curtailments alleviate an issue in one part of the system, curtailments can contribute to supply shortages or affect local transmission system operations in another area. During Winter Storm Elliott, firm exports were curtailed from PJM during a period of widespread energy emergencies in the U.S. Eastern Interconnection. For winter 2023–2024, several areas identified as having capacity or energy risks are relying on imports of electricity supplies. These areas include MRO-SaskPower, NPCC-Maritimes, NPCC-New England, SERC-Central, and SERC-East. A wide-area cold snap that severely affects regional demand or generator availability presents an added concern in areas that are dependent on imports for managing high electricity demand.
5. **New cold weather Reliability Standards in place at the start of the 2023–2024 winter are aimed at improving coordination between Generator Owners/Operators and BPS Operators.** New cold weather Reliability Standards adopted by the NERC Board of Trustees (Board) in June 2021 went into effect in the United States earlier this year. Generator Owners (GO) and Generator Operators (GOP) are required to implement plans for cold weather preparedness and provide cold weather operating parameters to their RCs, Transmission

Operators (TOP), and BAs for use in operating plans. Additional Reliability Standard requirements have been developed by NERC and industry to address further recommendations of the *FERC-NERC-Regional Entity staff report—The February 2021 Cold Weather Outages in Texas and Southcentral United States*. The NERC Board adopted these requirements in October 2023 and directed NERC to file them with regulatory authorities for approval and industry implementation.

6. **Industry responses to NERC’s Level 3 Alert - Cold Weather Preparations for Extreme Weather Events—III indicate that generator winter preparations are on a positive trend, but freezing temperatures remain a concern for some generators.** In May, NERC issued a Level 3 essential actions alert to BAs, TOPs, and GOs. The alert highlighted actions to increase readiness and enhance plans to reduce risk for the upcoming winter and beyond. Additionally, recipients of the alert were required to respond to questions that support NERC’s review of progress toward mitigating winter reliability risks. The responses indicate GOs have determined cold weather temperature limits for their generators and taken steps to assess and prepare critical components to operate at these temperatures. Many GOs, however, noted that generator unit and auxiliary component mechanical failures from past cold weather events remain a concern for the upcoming winter. Problem areas include improper heat tracing, frozen instrumentation and control equipment, generator circuit breaker tripping in low temperatures or low air pressures, and wind turbine blade icing.

Recommendations

To reduce the risks of energy shortfalls on the BPS this winter, NERC recommends the following:

- RCs, BAs, and TOPs in the elevated risk areas identified in the key findings should review seasonal operating plans and the protocols for communicating and resolving potential supply shortfalls in anticipation of potentially high generator outages and extreme demand levels. Operators should be trained and familiar with manual load shedding plans prior to winter and review procedures in advance of severe winter weather.
- TOPs, BAs, and GOs should implement the essential actions identified in the NERC Level 3 alert, Cold Weather Preparations for Extreme Weather Events–III, and should take recommended weatherization steps prior to winter.
- BAs should be cognizant of the potential for short-term load forecasts to underestimate load in extreme cold weather events and be prepared to take early action to implement protocols and procedures for managing potential reserve deficiencies.
- RCs and BAs should implement generator fuel surveys to monitor the adequacy of fuel supplies. They should prepare their operating plans to manage potential supply shortfalls and take proactive steps for generator readiness, fuel availability, load curtailment, and sustained operations in extreme conditions.
- State and provincial regulators can assist grid owners and operators in advance of and during extreme cold weather by supporting requested environmental and transportation waivers as well as public appeals for electricity and natural gas conservation.

Risk Highlights

Over the past 11 years, five cold weather events have jeopardized Bulk Electric System (BES) reliability by triggering unplanned cold weather-related generation outages. To maintain BES reliability during Winter Storm Uri in February 2021 and Winter Storm Elliott in December 2022, BES operators were required to shed firm load. During both winter storms, numerous electrical and mechanical issues rendered significant portions of the impacted areas' thermal generation fleet unavailable while natural gas supply and transportation issues prevented numerous otherwise available natural-gas-fired generators from supplying much needed electrical energy. Moreover, a significant portion of generating units failed to perform at temperatures above their own documented minimum operating temperatures.

Generator Fuel Supply Risk

As noted in past winter reliability assessments, the performance of the thermal generating fleet is critical to winter operations. The electric and natural gas industries continue to work through the recommendations contained in the *FERC-NERC-Regional Entity Staff Report: The February 2021 Cold Weather Outages in Texas and the South-Central United States*.² The final report on Winter Storm Elliott—the 2022 storm that contributed to power outages for millions of electricity customers in the Eastern half of the United States—recommends completion of cold weather reliability standard revisions stemming from 2021’s Winter Storm Uri and improvements to reliability for the U.S. natural gas infrastructure.³ What has become clear is that the natural-gas-electric system has now become fully interconnected, each requiring the other to remain reliable (i.e., impacts on one system can impact the other). These considerations should drive higher levels of coordination to ensure sustained reliable operation of this interconnected system.

² [The February 2021 Cold Weather Outages in Texas and the South-Central United States | FERC, NERC and Regional Entity Staff Report | Federal Energy Regulatory Commission](#)

³ [FERC Winter Storm Elliott Report](#)

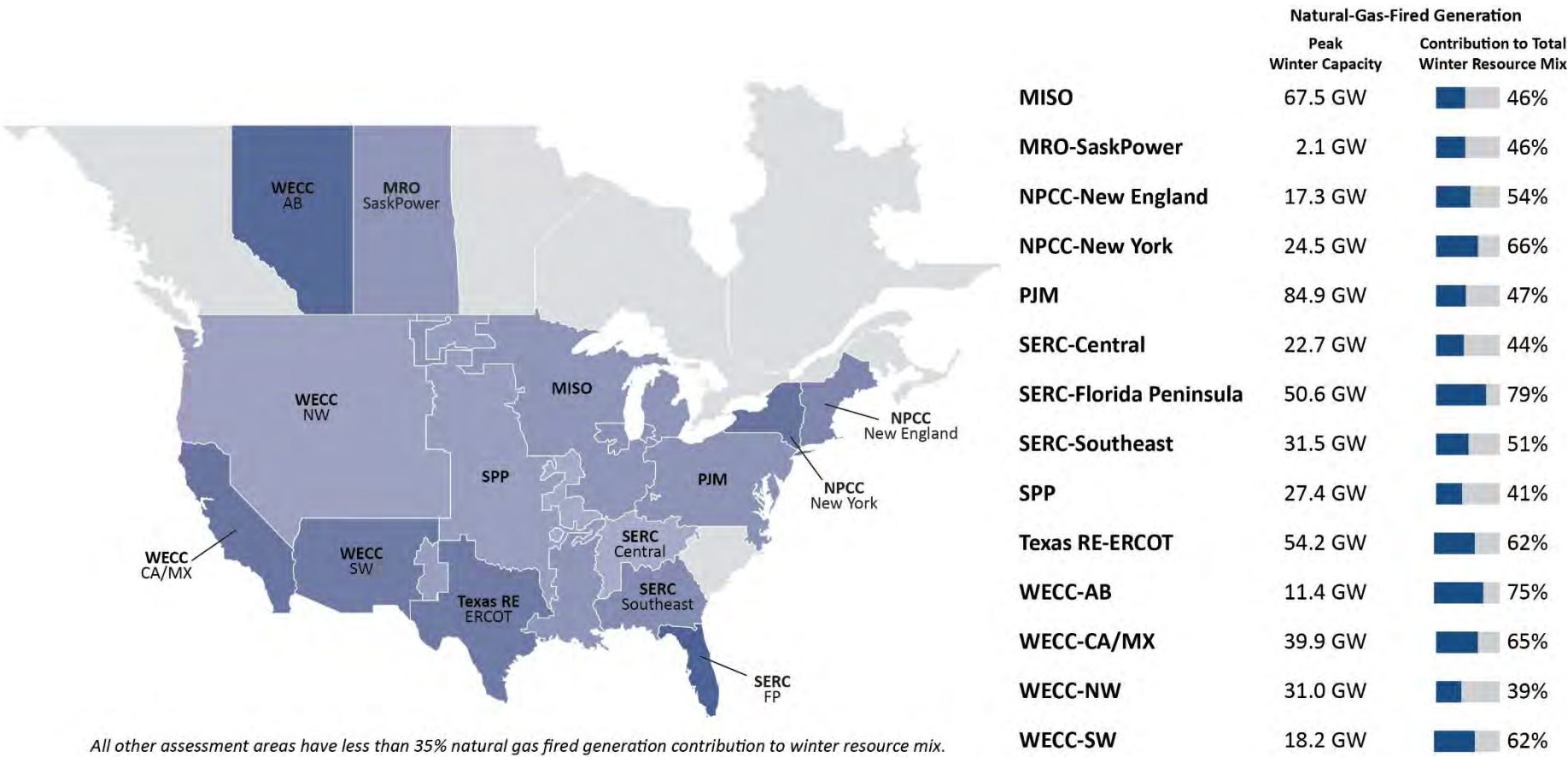


Figure 2: Natural-Gas-Fired Generation Capacity Contributions to 2023–2024 Winter Generation Mix

Natural Gas Supply to Generators
Natural-gas-fired generation is vitally important to meeting winter electricity demand across much of North America (Figure 2). Furthermore, the natural gas industry relies on electricity to power some of its critical components. For instance, some compressors run on electricity while others are fueled by natural gas. This means that the natural gas industry depends on the delivery of electricity to run as intended, and as stated in many other places, the electric industry depends on the delivery of natural gas. This can exacerbate the scale of impacts when either industry is threatened.

Generator availability and output can be threatened when natural gas supplies are insufficient or when natural gas infrastructure is unable to maintain the flow of fuel. The BES’s ability to deliver electricity was put at risk by past natural gas production declines during periods of extreme cold weather. As Winter Storm Elliott demonstrated, this is the case even in areas of North America where cold weather is common. Wide-area extreme cold events increase the likelihood of natural gas production declines and result in increased demand for natural gas by local distribution company (LDC) customers and natural-gas-fired electric generators. Wide-area events can also concurrently render multiple grid BA areas energy deficient and thus preclude an impacted BA from importing the electricity it requires to meet BA load even when transmission to support such transfers is available. Longer duration events increase the risk that the imbalances resulting from declining natural gas production and increased natural gas demand approach unsustainable levels. For areas that are pipeline constrained, high natural gas demand during extreme cold weather presents risks for generators that lack firm natural gas transportation arrangements.

Coal Transportation

While many factors that contributed to uncertain rail shipment of coal to electric generators prior to the 2022–2023 winter assessment have subsided, other transport issues could emerge for this winter. Drought conditions that impact the Missouri River and other major navigable waterways could restrict coal availability and cause units to run at a derated level to conserve coal inventory. Low water levels can also affect generators that rely on once-through cooling processes and limit the generator’s capacity output.

Extreme Cold Temperatures and Demand Forecasting

Accurate load forecasting is essential for reliable operations. BAs and load-serving entities frequently update the load forecasts that serve as key inputs for long-range resource planning, seasonal outage coordination, and operational plans from day-ahead to real-time. Cold weather patterns and the temperature-correlated behavior of some end-use loads present some of the most challenging issues and complex load forecasting, adding to winter reliability risk.

Most assessment areas can experience a wide range of winter peak demand from one year to the next, largely depending upon the severity of winter conditions. Load forecasts for normal winter peak (referred to as 50/50 peak demand or net internal demand elsewhere in this report) reflect the highest expected system load for an average winter. A higher level of demand used throughout this report is the load forecast for extreme 90/10 peak demand, which generally represents the highest 10% of the

winter peak demand forecast distribution.⁴ Actual winter peak demand in each area is expected to be below this level most (but not all) years. **Figure 3** shows these two demand levels for assessment areas where the extreme peak demand forecast is 9% or greater than the normal peak demand forecast. Year-to-year differences in winter weather conditions are key drivers of the large variation in normal and extreme demand forecasts, but changing load characteristics also contribute in many areas. ARMs, which measure resource levels above the normal 50/50 peak demand, have limited ability to identify resource adequacy risk when peak demand is highly variable from year to year.

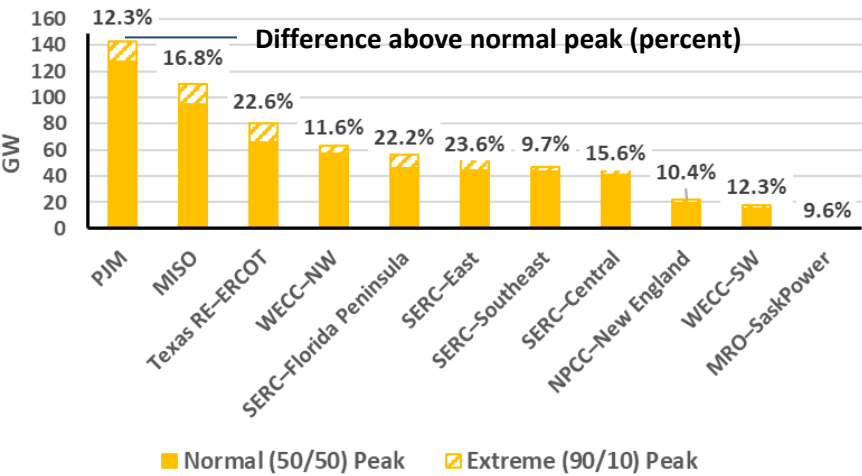


Figure 3: Normal and Extreme Peak Demand Forecasts for 2023–2024 Winter

The growing complexity in load forecasting and increasing load forecast uncertainty adds to winter reliability risks. Extreme cold temperatures and unfamiliar weather patterns characterized by strong cold fronts, wind, and precipitation can cause demand for electricity to deviate significantly from historical forecasts. Electrification of the heating sector is increasing temperature-sensitive load components while increasing levels of variable-output solar PV DERs add to load forecast uncertainty. Underestimating electricity demand prior to the arrival of cold temperatures can lead to ineffective operations planning and insufficient resources being scheduled. Generator performance and fuel issues are more likely to occur when generators are called upon with short notice, exposing BAs to potential resource shortfalls. Load serving entities and BAs should apply lessons from prior winter operating experience to operational load forecasts and pay particular attention to the risk of demand underestimation ahead of extreme cold temperatures.

⁴ Anticipated Reserve Margins (ARM) are calculated from this demand level. NERC assesses winter reliability risk using this extreme 90/10 peak demand level (see the risk scenario summary for each assessment area in the [Regional Assessments Dashboards](#) section).

Seasonal Risk Scenario Margins

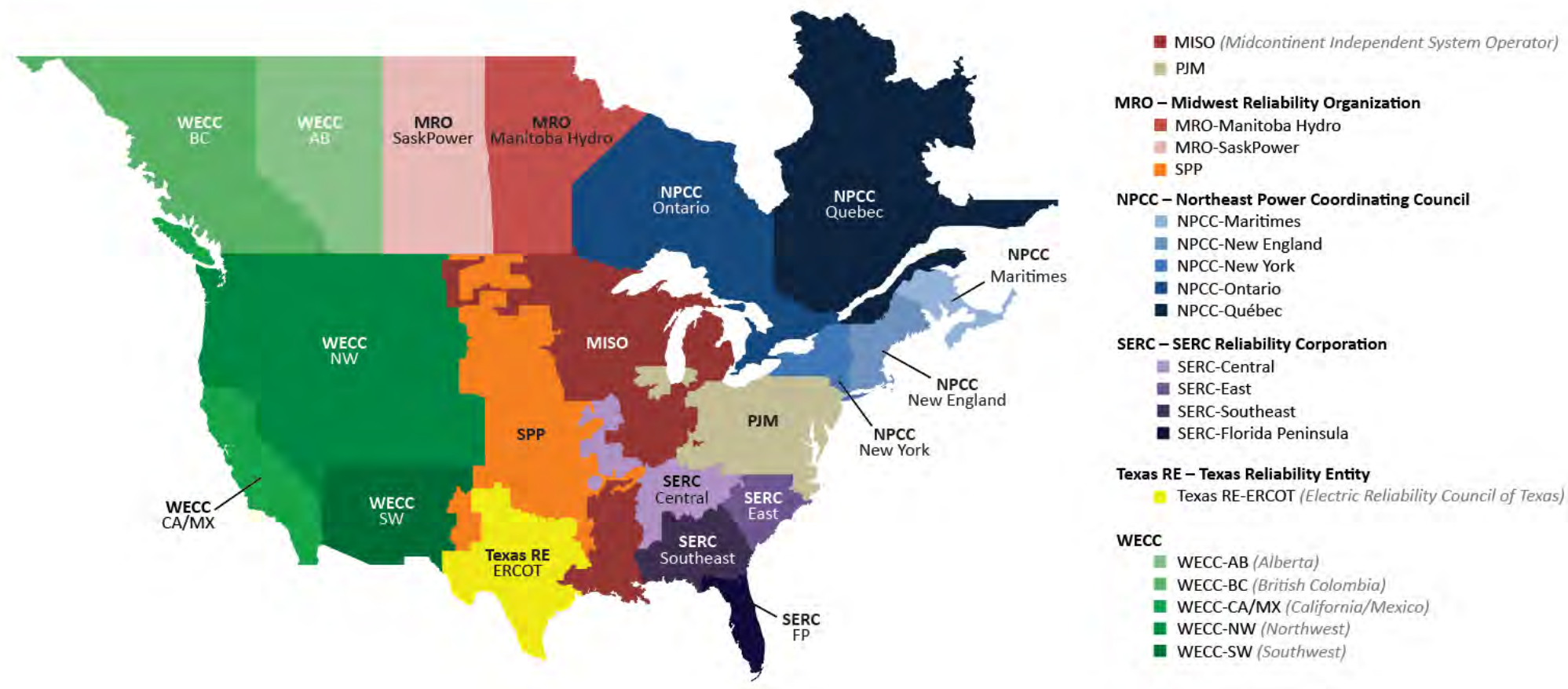
Seasonal risk scenarios for each assessment area are presented in the [Regional Assessments Dashboards](#) section. The on-peak reserve margins and seasonal risk scenario chart in each dashboard provide potential winter peak demand and resource condition information. The reserve margins on the right side of the dashboard pages provide a comparison to the previous year’s assessment. The seasonal risk scenario charts present deterministic scenarios for further analysis of different demand and resource levels with adjustments for normal and extreme conditions. The assessment areas determined the adjustments to capacity and peak demand based on methods or assumptions that are summarized below the seasonal risk scenario charts; see the [Data Concepts and Assumptions](#) section for more information about these charts.

The seasonal risk scenario charts can be expressed in terms of reserve margins. In [Table 1](#), each assessment area’s ARM is shown alongside the reserve margins for a typical generation outage scenario (where applicable) and the extreme demand and resource conditions in their seasonal risk scenario. The typical outages reserve margin is comprised of anticipated resources less the capacity that is likely to be in maintenance or forced outage at peak demand. If the typical maintenance or forced outage margin is the same as the ARM, it is because an assessment area has already factored typical outages into the anticipated resources. The extreme conditions margin includes all components of the scenario and represents the most severe operating conditions of an area’s scenario. Note that any reserve margin below zero indicates that the resources fall below demand in the scenario.

Table 1: Seasonal Risk Scenario Margins			
Assessment Area	Anticipated Reserve Margin	Typical Outages	Extreme Conditions
MISO	55.8%	26.5%	-5.9%
MRO-Manitoba	15.3%	13.2%	6.6%
MRO-SaskPower	20.6%	6.9%	7.7%
NPCC-Maritimes	19.7%	13.5%	-0.5%
NPCC-New England	67.2%	47.3%	6.3%
NPCC-New York	76.3%	49.9%	12.4%
NPCC-Ontario	28.2%	28.2%	20.3%
NPCC-Quebec	10.5%	6.5%	-2.2%
PJM	39.8%	26.4%	4.2%
SERC-C	30.1%	22.6%	5.2%
SERC-E	24.4%	19.6%	9.3%
SERC-FP	41.0%	37.8%	12.7%
SERC-SE	41.6%	35.7%	13.7%
SPP	38.8%	14.5%	-14.1%
TRE-ERCOT	41.2%	27.3%	-6.6%
WECC-AB	27.1%	24.3%	5.5%
WECC-BC	15.1%	15.0%	-8.6%
WECC-CA/MX	65.3%	57.4%	32.2%
WECC-NW	43.5%	37.5%	-4.1%
WECC-SW	90.4%	85.1%	43.4%

Regional Assessments Dashboards

The following assessment area dashboards and summaries were developed based on data and narrative information collected by NERC from the six Regional Entities on an assessment area basis. Guidelines and definitions are in the [Data Concepts and Assumptions](#) table. On-Peak Reserve Margin bar charts show the ARM compared to a Reference Margin Level that is established for the areas to meet resource adequacy criteria. Prospective Reserve Margins can give an indication of additional on-peak capacity but are not used for assessing adequacy. The operational risk analysis shown in the following regional assessments dashboard pages provides a deterministic scenario for understanding how various factors that affect resources and demand can combine to impact overall resource adequacy. For each assessment area, there is a risk-period scenario graphic; the left blue column shows anticipated resources (from the [Demand and Resource Tables](#)), and the two orange columns at the right show the two demand scenarios of the normal peak net internal demand (from the [Demand and Resource Tables](#)) and the extreme winter peak demand determined by the assessment area. The middle red or green bars show adjustments that are applied cumulatively to the anticipated resources. Adjustments may include reductions for typical generation outages (maintenance and forced not already accounted for in anticipated resources) and additions that represent the quantified capacity from operational tools (if any) that are available during scarcity conditions but have not been accounted for in the WRA reserve margins. Resources throughout the scenario are compared against expected operating reserve requirements that are based on peak load and normal weather. The cumulative effects from extreme events are also factored in through additional resource derates or low-output scenarios. In addition, results from a probability-based resource adequacy assessment are shown in the Highlights section of each dashboard. Methods vary by assessment area and provide further insights into the risk conditions forecasted for this upcoming winter period.





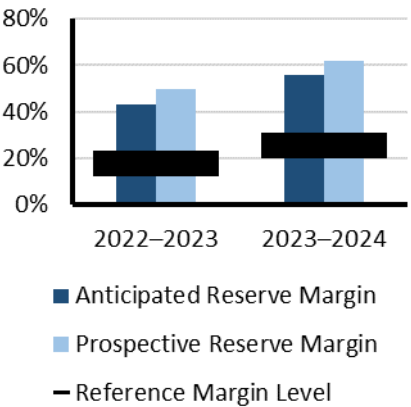
MISO

MISO is a not-for profit, member-based organization that administers wholesale electricity markets that provide customers with valued service; reliable, cost-effective systems and operations; dependable and transparent prices; open access to markets; and planning for long-term efficiency. MISO manages energy, reliability, and operating reserve markets that consist of 39 local BAs and over 500 market participants, serving approximately 45 million customers. Although parts of MISO fall in three Regional Entities, MRO is responsible for coordinating data and information submitted for NERC’s reliability assessments.

Highlights

- Though some risk has been identified for this upcoming winter season in a high generation outage and high winter load scenario, reliability is expected to be maintained by the use of any number of measures, including load modifying resources, non-firm energy transfers into the system, energy-only resources that do not have a must-offer requirement for the winter but may still offer into the energy markets, or internal transfers that exceed the sub-regional import/export constraint between MISO North/Central and MISO South. MISO continues to coordinate extensively with neighboring RCs and BAs to improve situational awareness and vet any needs for firm or non-firm transfers to address extreme system conditions.
- The extreme cold weather of last winter is a reminder of just how critical resource adequacy and proper planning are for all seasons of the year, not just for a systems summer peak. Acknowledging this, MISO continues to survey and coordinate with its members on winter preparedness and fuel sufficiency. In addition, MISO has filed and implemented a seasonal resource adequacy construct and seasonal unit accreditation to better affirm adequate supply in all seasons. As a result, MISO has raised Reference Margin Levels for the 2023–2024 winter season. The 2023–2024 Planning Resource Auction conducted in April 2023 was the first implemented under the seasonal construct.

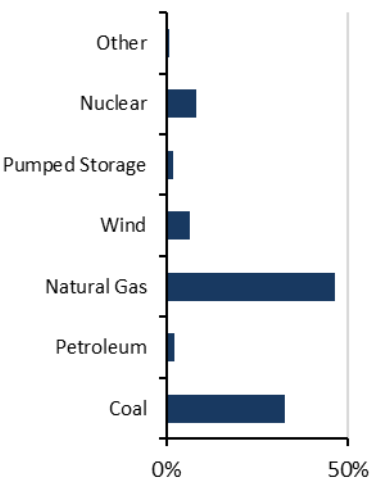
On-Peak Reserve Margin



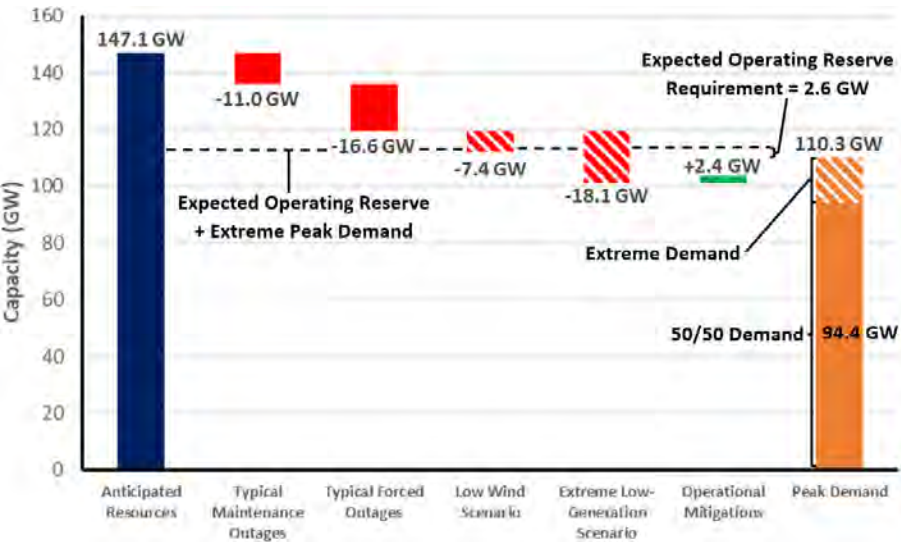
Risk Scenario Summary

Expected resources meet operating reserve requirements under normal peak demand scenarios. Above-normal winter peak load and outage conditions could result in the need to employ operating mitigations (i.e., demand response and transfers) and energy emergency alerts (EEA). Load shedding is unlikely but may be needed under wide-area cold weather events.

On-Peak Fuel Mix

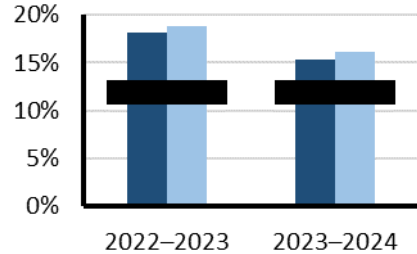
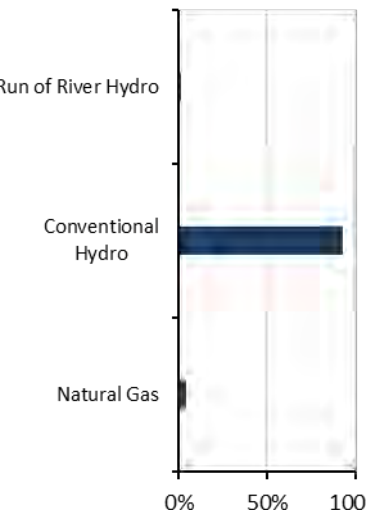
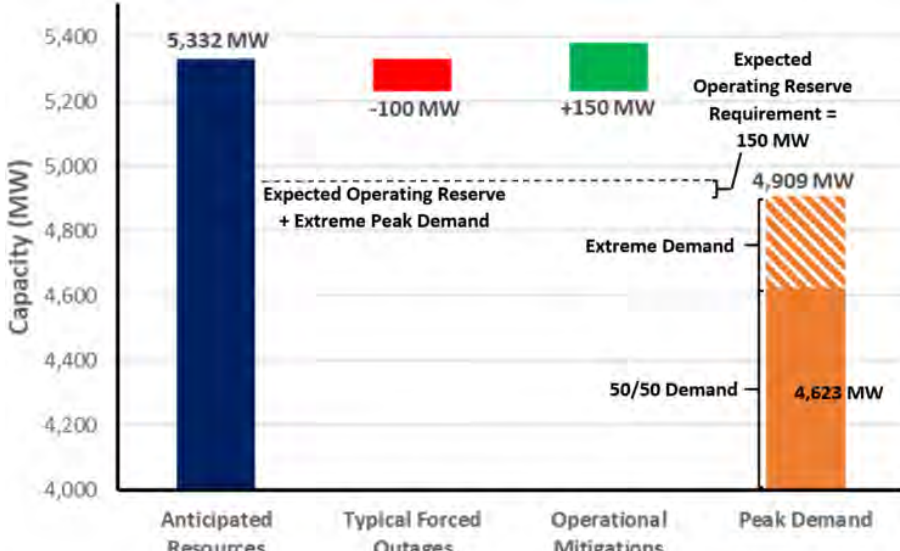


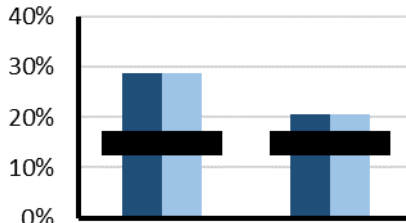
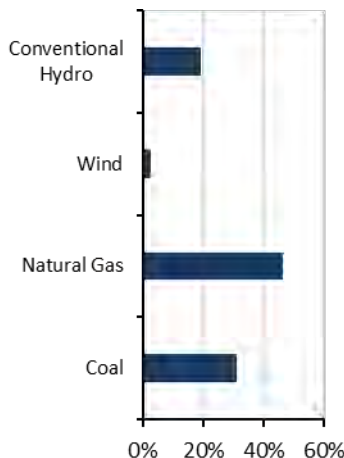
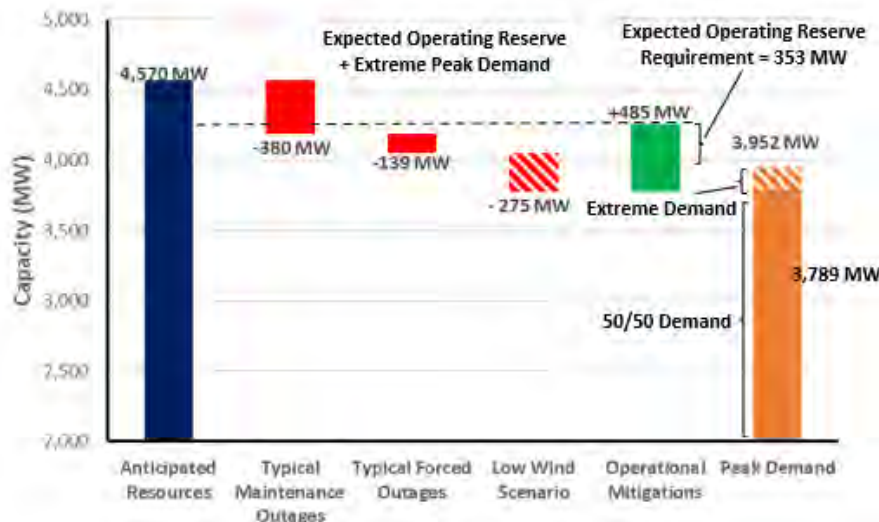
2023–2024 Winter Risk Period Scenario

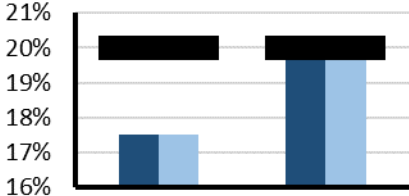
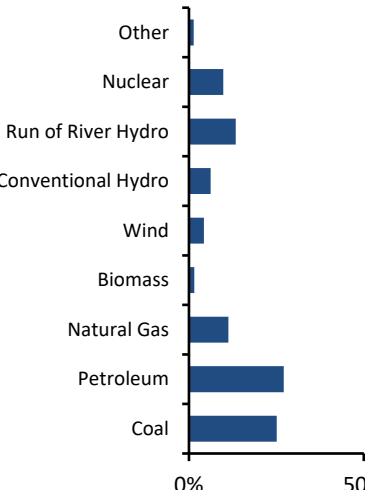
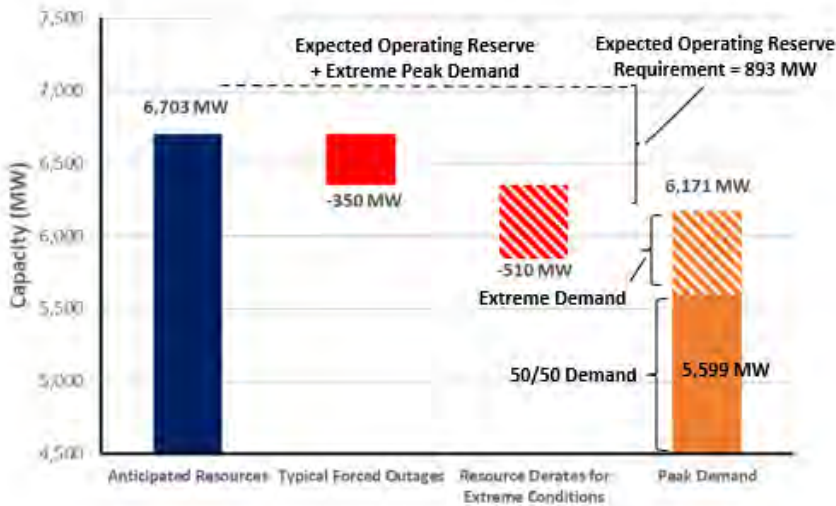


Scenario Description (See Data Concepts and Assumptions)

- Risk Period:** Highest risk for unserved energy at peak demand hour
- Demand Scenarios:** Net internal demand (50/50) and (90/10) demand forecast using 30 years of historical data
- Maintenance Outages:** Rolling five-year winter average of maintenance and planned outages
- Forced Outages:** Five-year average of all outages that were not planned
- Low Wind Scenario:** Below average wind contributions
- Extreme Low-Generation:** Maximum historical generation outages
- Operational Mitigations:** A total of 2.6 GW capacity resources available during extreme operating conditions

	MRO-Manitoba Hydro Manitoba Hydro is a provincial Crown Corporation and one of the largest integrated electricity and natural gas distribution utilities in Canada. Manitoba Hydro is a leader in providing renewable energy and clean-burning natural gas Manitoba Hydro provides electricity to approximately 608,500 electricity customers in Manitoba and provides approximately 293,000 customers with natural gas in Southern Manitoba. The service area is the province of Manitoba, which is 251,000 square miles Manitoba Hydro is winter-peaking. Manitoba Hydro is its own Planning Coordinator (PC) and BA. Manitoba Hydro is a coordinating member of MISO. MISO is the RC for Manitoba Hydro.	
Highlights • The ARM for winter 2023–2024 exceeds the 12% Reference Margin Level. • No emerging reliability issues are anticipated for the upcoming winter season that are pertinent to Manitoba Hydro. • Manitoba Hydro continues to monitor a number of issues, including extreme weather events like drought, decarbonization-driven changes to supply and demand, and asset health. • All seven units at the Keeyask hydro station (630 MW net addition) are anticipated to be in commercial operation for winter 2023–2024.		On-Peak Reserve Margin  2022–2023 2023–2024 ■ Anticipated Reserve Margin ■ Prospective Reserve Margin — Reference Margin Level
Risk Scenario Summary Expected resources meet operating reserve requirements under the assessed scenarios.		
On-Peak Fuel Mix 	2023–2024 Winter Risk Period Scenario 	Scenario Description (See Data Concepts and Assumptions) Risk Period: Highest risk for unserved energy at peak demand hour Demand Scenarios: Net internal demand (50/50) and extreme demand scales additional load experienced during all-time peak actual versus forecasted load (January 2019) Forced Outages: Accounts for average forced outages Operational Mitigations: Emergency Operating Procedures

	MRO-SaskPower MRO-SaskPower is an assessment area in the Saskatchewan province of Canada. The province has a geographic area of 651,900 square kilometers (251,700 square miles) and a population of approximately 1.2 million. Peak demand is experienced in the winter. The Saskatchewan Power Corporation (SaskPower) is the PC and RC for the province of Saskatchewan and is the principal supplier of electricity in the province. SaskPower is a provincial crown corporation and, under provincial legislation, is responsible for the reliability oversight of the Saskatchewan BES and its Interconnections.																															
Highlights - Saskatchewan experiences peak load in winter because of extreme cold weather. Reserve margins have fallen this winter by about 8% when compared to the previous winter due to increased peak demand projections, the retirement of a natural gas unit (95 MW), and an increase of planned maintenance. - The risk of operating reserve shortage or EEA during peak load times exists if a large generation forced outage occurs during peak load times combined with transmission tie-line maintenance work or generation maintenance work scheduled during winter months. - In case of extreme winter conditions combined with large generation forced outages, SaskPower would utilize available demand response programs, short-term power transfers from neighboring utilities, maintenance rescheduling, and/or short-term load interruptions.		On-Peak Reserve Margin  <table><thead><tr><th>Year</th><th>Anticipated Reserve Margin</th><th>Prospective Reserve Margin</th><th>Reference Margin Level</th></tr></thead><tbody><tr><td>2022-2023</td><td>~28%</td><td>~28%</td><td>~15%</td></tr><tr><td>2023-2024</td><td>~20%</td><td>~20%</td><td>~15%</td></tr></tbody></table> ■ Anticipated Reserve Margin ■ Prospective Reserve Margin — Reference Margin Level	Year	Anticipated Reserve Margin	Prospective Reserve Margin	Reference Margin Level	2022-2023	~28%	~28%	~15%	2023-2024	~20%	~20%	~15%																		
Year	Anticipated Reserve Margin	Prospective Reserve Margin	Reference Margin Level																													
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2023-2024	~20%	~20%	~15%																													
Risk Scenario Summary Expected resources do not meet operating reserve requirements under normal peak-demand scenarios. Normal winter peak load and outage conditions could result in the need to employ operating mitigations (i.e., demand response, transfers, appeals) and EEAs. The risk of load shedding is low.																																
On-Peak Fuel Mix  <table><thead><tr><th>Fuel Type</th><th>Percentage</th></tr></thead><tbody><tr><td>Conventional</td><td>~18%</td></tr><tr><td>Hydro</td><td>~12%</td></tr><tr><td>Wind</td><td>~2%</td></tr><tr><td>Natural Gas</td><td>~45%</td></tr><tr><td>Coal</td><td>~23%</td></tr></tbody></table>	Fuel Type	Percentage	Conventional	~18%	Hydro	~12%	Wind	~2%	Natural Gas	~45%	Coal	~23%	2023-2024 Winter Risk Period Scenario  <table><thead><tr><th>Category</th><th>Value (MW)</th></tr></thead><tbody><tr><td>Anticipated Resources</td><td>4,570</td></tr><tr><td>Typical Maintenance Outages</td><td>-380</td></tr><tr><td>Typical Forced Outages</td><td>-139</td></tr><tr><td>Low Wind Scenario</td><td>-275</td></tr><tr><td>Operational Mitigations</td><td>+485</td></tr><tr><td>Expected Operating Reserve + Extreme Peak Demand</td><td>3,952</td></tr><tr><td>Expected Operating Reserve Requirement</td><td>353</td></tr><tr><td>50/50 Demand</td><td>3,789</td></tr></tbody></table>	Category	Value (MW)	Anticipated Resources	4,570	Typical Maintenance Outages	-380	Typical Forced Outages	-139	Low Wind Scenario	-275	Operational Mitigations	+485	Expected Operating Reserve + Extreme Peak Demand	3,952	Expected Operating Reserve Requirement	353	50/50 Demand	3,789	Scenario Description (See Data Concepts and Assumptions) Risk Period: Highest risk for unserved energy at peak demand hour Demand Scenarios: Net internal demand (50/50) and above-normal scenario based on potential system peak load increased by average forecast error of previous five years Maintenance Outages: Average of planned maintenance outages for the winter months, December-February, over the past three years Forced Outages: Estimated using SaskPower forced outage model Low Wind Scenario: Estimated using SaskPower forced outage model Operational Mitigations: Estimated average value based on short term transfer capability from neighboring utilities (150 MW) and reserved generating units (135 MW) for the upcoming 2023-2024 winter. This also includes 200 MW in demand-side resources and non-firm loads that require 15 minutes to 2 hours of advanced notification.
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	NPCC-Maritimes The Maritimes assessment area is a winter-peaking NPCC area that contains two BAs. It is comprised of the Canadian provinces of New Brunswick, Nova Scotia, and Prince Edward Island, and the northern portion of Maine, which is radially connected to the New Brunswick power system. The area covers 58,000 square miles with a total population of 1.9 million.										
Highlights - The Maritimes area has not identified any operational issues that are expected to impact system reliability. If an event was to occur, there are emergency operations and planning procedures in place. All of the area’s declared firm capacity is expected to be operational for the winter operating period. - The Maritimes area is a winter-peaking system. - As part of the planning process, dual-fueled units will have sufficient supplies of heavy fuel oil on-site to enable sustained operation in the event of natural gas supply interruptions. Risk Scenario Summary Expected resources do not meet operating reserve requirements under normal peak-demand scenarios. Normal winter peak load and outage conditions could result in the need to employ operating mitigations (i.e., demand response, transfers, appeals) and EEAs. NPCC probabilistic analysis indicates that the risk of load shedding is low. See Probabilistic Assessment section.		On-Peak Reserve Margin  <table border="1" data-bbox="2139 630 2548 662"> <thead> <tr> <th>Year</th> <th>Anticipated Reserve Margin</th> <th>Prospective Reserve Margin</th> </tr> </thead> <tbody> <tr> <td>2022–2023</td> <td>~17.5%</td> <td>~17.8%</td> </tr> <tr> <td>2023–2024</td> <td>~20.5%</td> <td>~20.8%</td> </tr> </tbody> </table> ■ Anticipated Reserve Margin ■ Prospective Reserve Margin — Reference Margin Level	Year	Anticipated Reserve Margin	Prospective Reserve Margin	2022–2023	~17.5%	~17.8%	2023–2024	~20.5%	~20.8%
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2022–2023	~17.5%	~17.8%									
2023–2024	~20.5%	~20.8%									
On-Peak Fuel Mix 	2023–2024 Winter Risk Period Scenario 	Scenario Description (See Data Concepts and Assumptions) Risk Period: Highest risk for unserved energy at peak demand hour Demand Scenarios: Net internal demand (50/50) and (90/10) demand forecast using 20 years of historical data Forced Outages: Based on historical operating experience Extreme Derates: A low likelihood scenario resulting in an additional 50% derate in the remaining capacity of both natural gas and wind resources under extreme conditions									



NPCC-New England

NPCC-New England is an assessment area that is served by ISO-NE, and it consists of the states of Connecticut, Maine, Massachusetts, New Hampshire, Rhode Island, and Vermont. ISO-NE is a regional transmission organization that is responsible for the reliable day-to-day operation of New England’s bulk power generation and transmission system, administration of the area’s wholesale electricity markets, and management of the comprehensive planning of the regional BPS. The New England BPS serves approximately 14.5 million customers over 68,000 square miles.

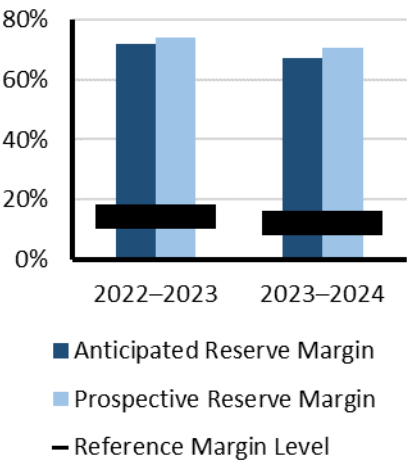
Highlights

- ISO-NE expects to meet its regional resource adequacy requirements this 2023–2024 winter operating period for a mild or moderate winter similar to 2021–2022 or 2017–2018. A standing concern is whether there will be sufficient energy available to satisfy electricity demand during an extended cold period given the existing resource mix, fuel delivery infrastructure, and expected fuel arrangements without considerable effort to replenish stored fuels (i.e., fuel oil and liquified natural gas).
- ISO-NE is offering an interim program to compensate certain resources that provide fuel security. The Inventoried Energy Program is a voluntary, interim program designed to provide incremental compensation for participants that maintain inventoried energy for their assets during extreme cold periods when winter energy security is most stressed.
- ISO-NE expects to have sufficient capacity resources to meet the 2023–2024 90/10 winter peak demand forecast of 21,032 MW for the weeks beginning January 7, January 14, and January 21, 2024.
- ISO-NE evaluates an above 90/10 scenario, which captures the area’s coldest day in the last 25 years while using both their current and future load models. The above 90/10 winter peak demand forecast is 21,746 MW for the three previously identified peak weeks. ISO-NE currently has sufficient resources to meet this demand however if a cold snap were to occur the area may have to rely on its external ties and emergency procedures to operate reliably.

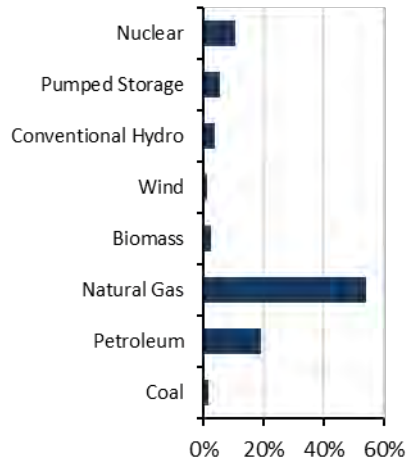
Risk Scenario Summary

Expected resources meet operating reserve requirements under normal peak demand scenarios. Above-normal winter peak load and outage conditions could result in the need to employ operating mitigations (i.e., demand response and transfers) and EEAs. Load shedding is unlikely but may be needed under wide-area prolonged cold weather events. See [Probabilistic Assessment](#) section.

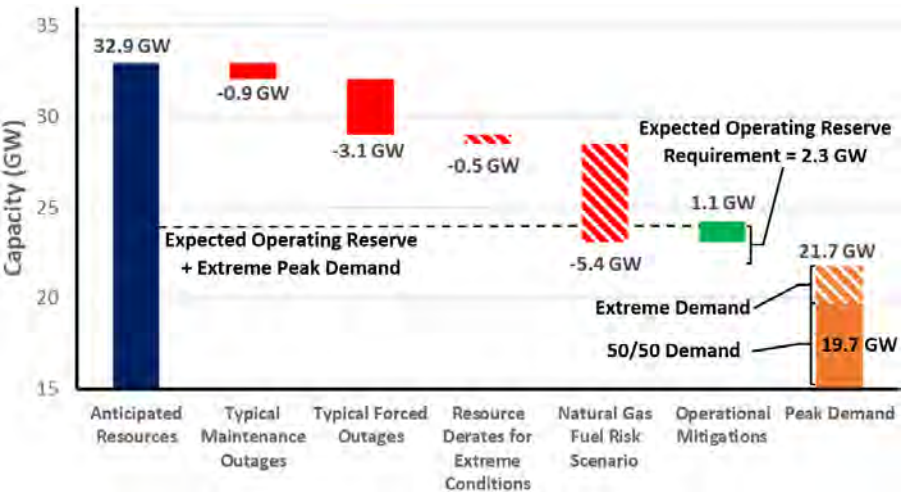
On-Peak Reserve Margin



On-Peak Fuel Mix



2023–2024 Winter Risk Period Scenario



Scenario Description (See [Data Concepts and Assumptions](#))

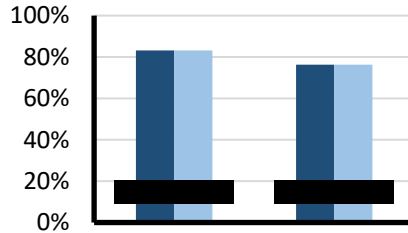
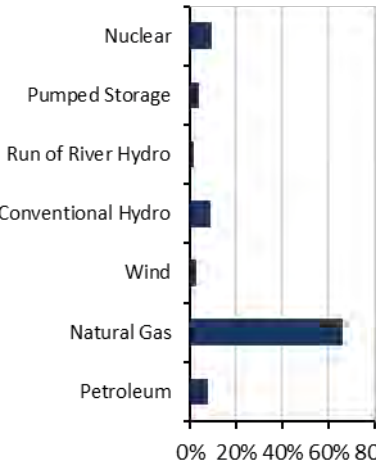
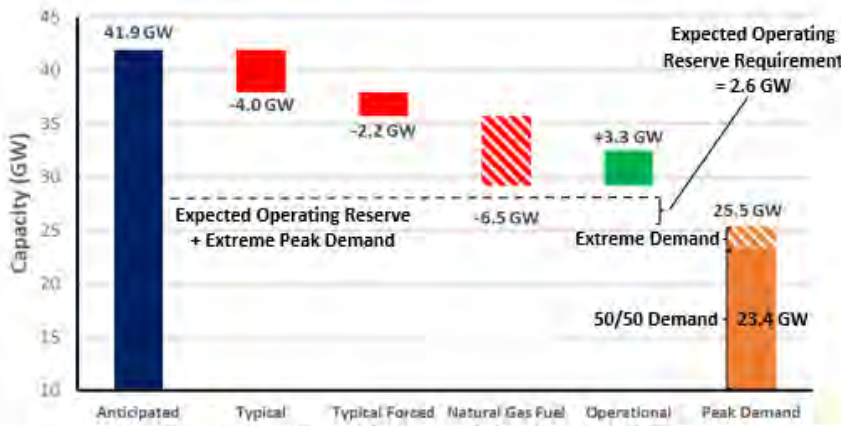
Risk Period: Highest risk for unserved energy at peak demand hour

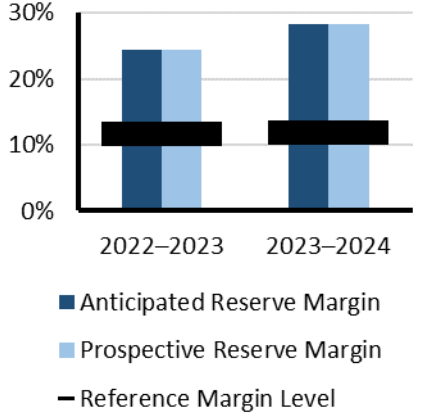
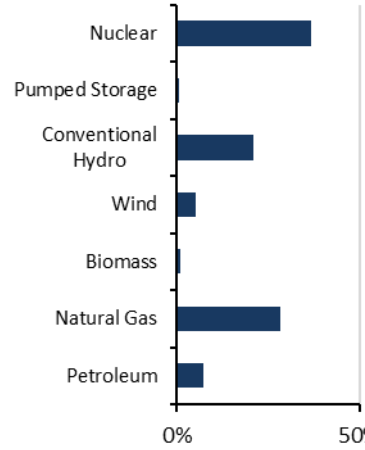
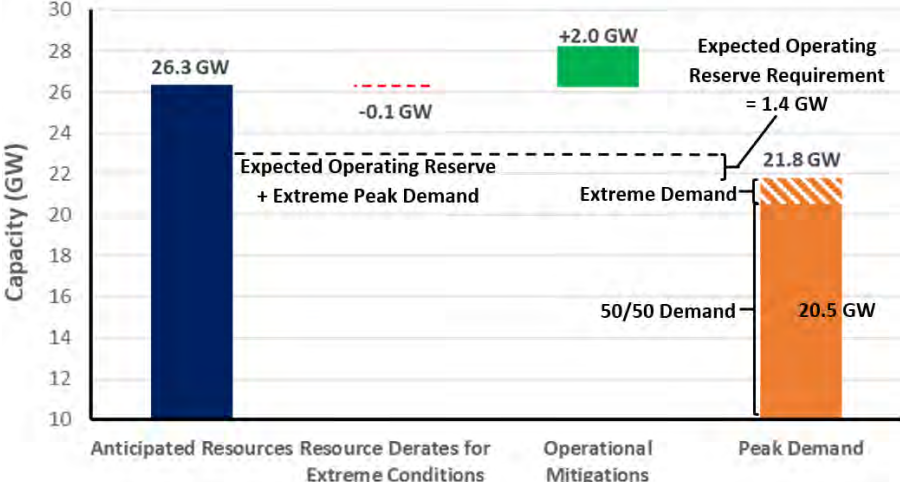
Demand Scenarios: Net internal demand (50/50) and extreme demand forecast for coldest day from the last 25 years

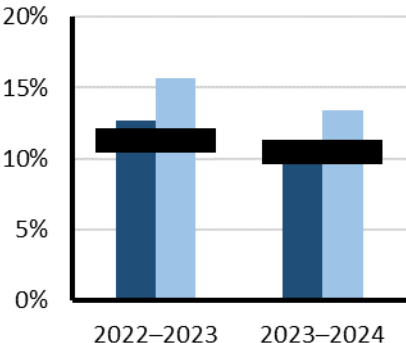
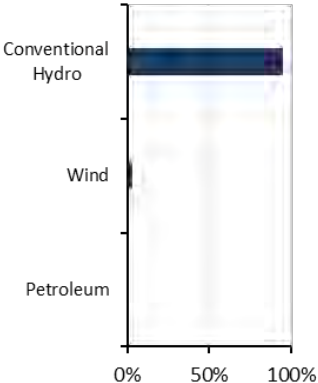
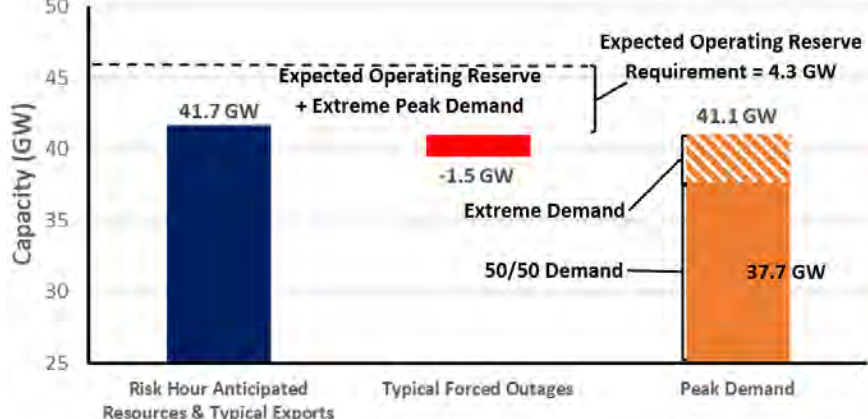
Maintenance and Forced Outages: Based on weekly averages

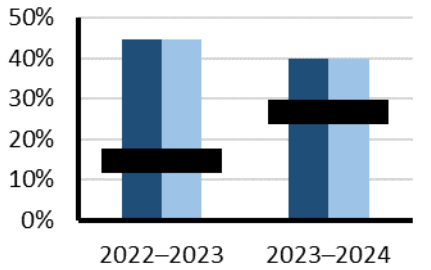
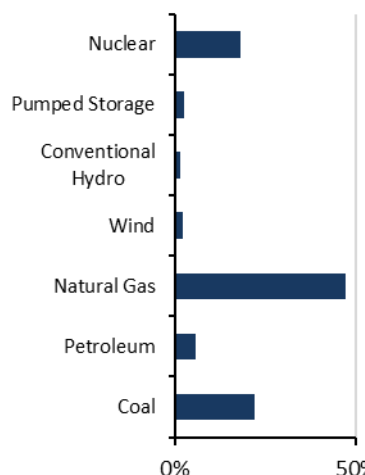
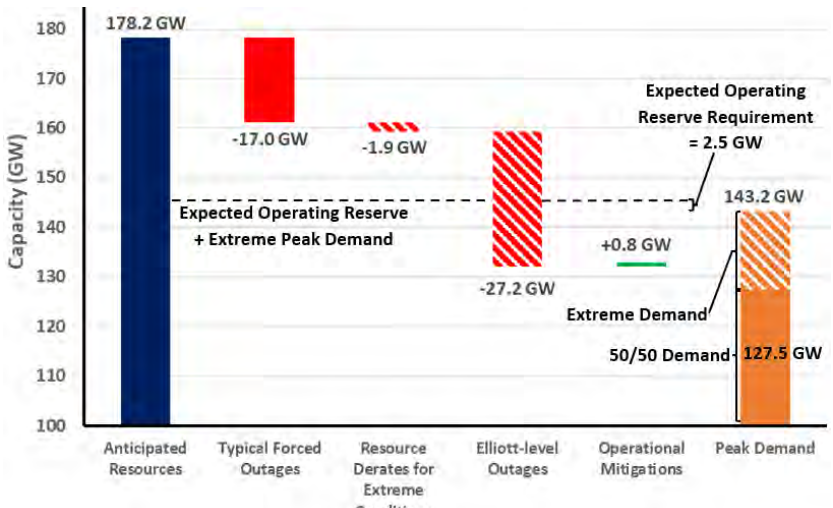
Extreme Derates and Natural Gas Scenario: Represent a case that is beyond the (90/10) conditions based on historical observation of force outages and additional reductions for generation at risk due to natural gas supply and cold weather-related outages reported by generators

Operational Mitigations: Based on ISO-NE operating procedures

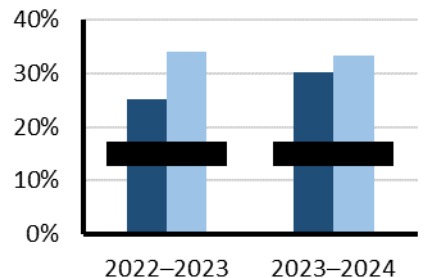
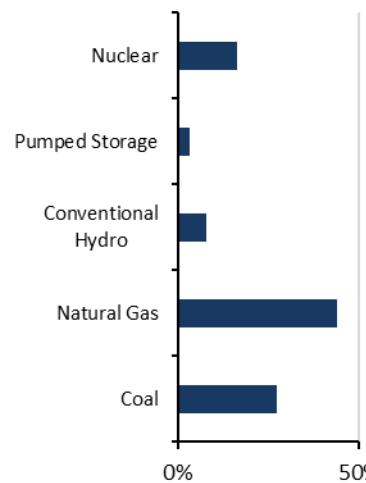
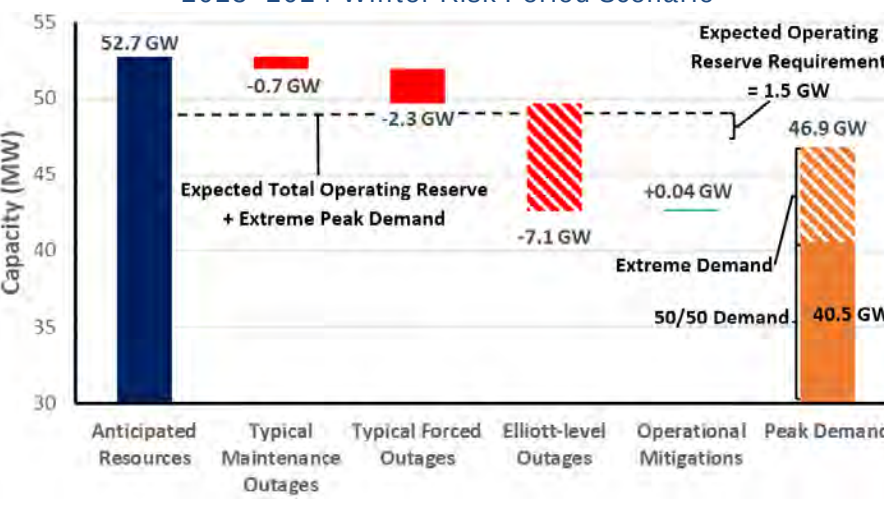
	NPCC-New York NPCC-New York is an assessment area consisting of the New York ISO (NYISO) service territory. NYISO is responsible for operating New York’s BPS, administering wholesale electricity markets, and conducting system planning. NYISO is the only BA within the state of New York. The BPS encompasses over 11,000 miles of transmission lines, 760 power generation units, and serves 20.2 million customers. For this WRA, the established Reference Margin Level is 15%; wind, grid-connected solar PV, and run-of-river totals were derated for this calculation. However, New York requires load-serving entities to procure capacity for their loads equal to their peak demand plus an Installed Reserve Margin (IRM). The IRM requirement represents a percentage of capacity above peak load forecast and is approved annually by the New York State Reliability Council. New York State Reliability Council approved the 2023–2024 IRM at 20.0%.														
Highlights New York is a summer-peaking area, and no emerging reliability issues are anticipated during the 2023–2024 winter assessment period. Surplus capacity margins above the NYISO’s operating reserve requirements are projected.		On-Peak Reserve Margin  <table><thead><tr><th>Year</th><th>Anticipated Reserve Margin</th><th>Prospective Reserve Margin</th><th>Reference Margin Level</th></tr></thead><tbody><tr><td>2022–2023</td><td>~82%</td><td>~80%</td><td>20%</td></tr><tr><td>2023–2024</td><td>~75%</td><td>~73%</td><td>20%</td></tr></tbody></table>		Year	Anticipated Reserve Margin	Prospective Reserve Margin	Reference Margin Level	2022–2023	~82%	~80%	20%	2023–2024	~75%	~73%	20%
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Risk Scenario Summary Expected resources meet operating reserve requirements under the assessed scenarios.															
On-Peak Fuel Mix 	2023–2024 Winter Risk Period Scenario 														
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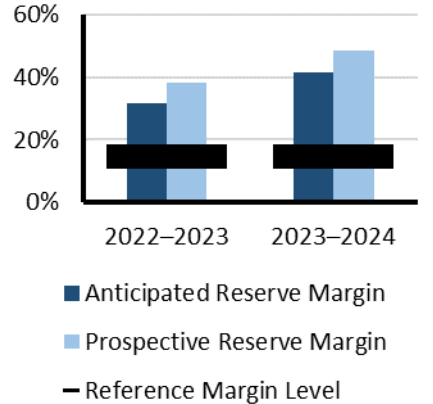
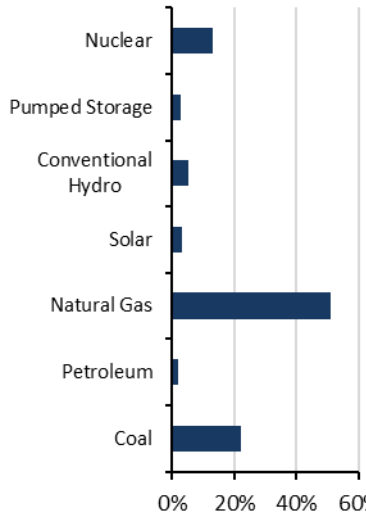
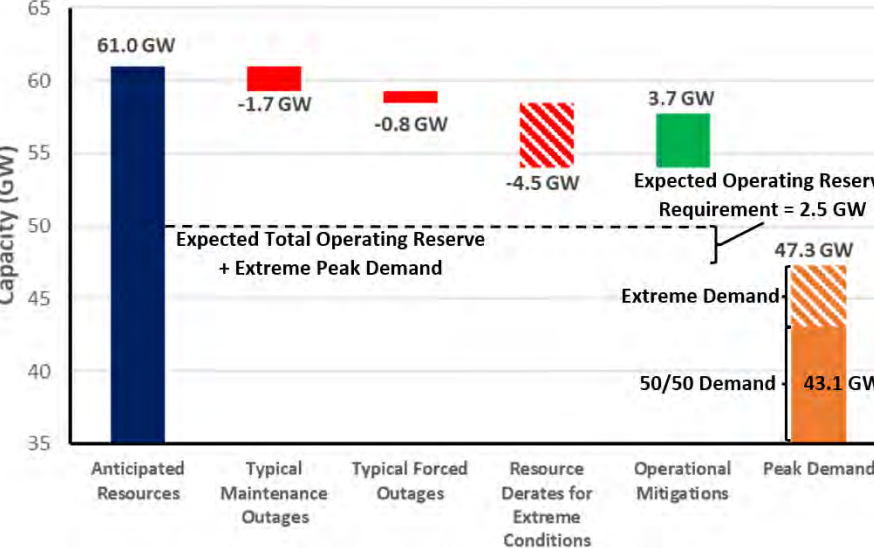
	NPCC-Ontario NPCC-Ontario is an assessment area in the Ontario province of Canada. The Independent Electricity System Operator (IESO) is the BA for the province of Ontario. The province of Ontario covers more than 1 million square kilometers (415,000 square miles) and has a population of more than 15 million. Ontario is interconnected electrically with Québec, MRO-Manitoba, states in MISO (Minnesota and Michigan), and NPCC-New York.	
Highlights - IESO anticipates that it will maintain reliability on its system through the winter of 2023–2024. - Reference margins are forecast to remain at adequate levels in both normal and extreme weather scenarios. - Ontario regularly experiences extreme cold weather; its generation fleet, transmission system, and fuel delivery infrastructure are well prepared for and adapted to such conditions. - Unit 3 at the Darlington Nuclear Generating Station was reconnected to the provincial grid following refurbishment in July 2023, nearly six months ahead of schedule. Bruce Nuclear Generating Station’s Unit 6 was returned to service following a successful refurbishment that began in January 2020. - The IESO’s December 2022 Annual Capacity Auction secured 1,160 MW of capacity for winter 2023–2024.		On-Peak Reserve Margin 
On-Peak Fuel Mix 	2023–2024 Winter Risk Period Scenario 	Scenario Description (See Data Concepts and Assumptions) Risk Period: Highest risk for unserved energy at peak demand hour Demand Scenarios: Net internal demand (50/50 Forecast) and highest weather-adjusted daily demand from 31 years of winter demand history Extreme Derates: Generation unavailability in an extreme event using temperature derates Operational Mitigations: Imports anticipated from neighbors during emergencies

	NPCC-Québec The Québec assessment area (Province of Québec) is a winter-peaking NPCC area that covers 595,391 square miles with a population of 8 million. Québec is one of the four Interconnections in North America, and it has ties to Ontario, New York, New England, and the Maritimes that consist of either high voltage direct current ties, radial generation, or load to and from neighboring systems.													
Highlights • Québec predicts that it will maintain system resource adequacy this winter. • Forecasted demand increase and additional firm export commitments have resulted in shrinking reserve margins. • The Québec area is a winter-peaking system with predominately hydroelectric generation resources. Adequate capacity margins above its reference reserve requirements are projected for the 2023–2024 winter assessment period. • No changes have been made to the assessment area’s winter preparedness programs.		On-Peak Reserve Margin  <table><tr><th>Year</th><th>Anticipated Reserve Margin</th><th>Prospective Reserve Margin</th><th>Reference Margin Level</th></tr><tr><td>2022–2023</td><td>~12.5%</td><td>~15.5%</td><td>11%</td></tr><tr><td>2023–2024</td><td>~10.5%</td><td>~13.5%</td><td>11%</td></tr></table>	Year	Anticipated Reserve Margin	Prospective Reserve Margin	Reference Margin Level	2022–2023	~12.5%	~15.5%	11%	2023–2024	~10.5%	~13.5%	11%
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On-Peak Fuel Mix 	2023–2024 Winter Risk Period Scenario 	Scenario Description (See Data Concepts and Assumptions) Risk Period: Highest risk for unserved energy at hour ending 8:00 a.m. Demand Scenarios: Net internal demand (50/50) and (95/5) demand forecast Forced Outages: Rare scenario of 1,500 MW in unplanned outages												

	PJM PJM Interconnection is a regional transmission organization that coordinates the movement of wholesale electricity in all or parts of Delaware, Illinois, Indiana, Kentucky, Maryland, Michigan, New Jersey, North Carolina, Ohio, Pennsylvania, Tennessee, Virginia, West Virginia, and the District of Columbia. PJM serves 65 million customers and covers 369,089 square miles. PJM is a BA, PC, Transmission Planner, Resource Planner, Interchange Authority, TOP, Transmission Service Provider, and RC.
Highlights - Installed capacity is significantly higher (13 percentage points) than PJM’s Reserve Requirements. PJM does not expect to encounter resource problems for anticipated conditions over the 2023–2024 winter Peak season. - A severe cold weather event that extends to the South can lead to energy emergencies as operators face sharp increases in generator forced outages and electricity demand. Forecasted peak demand has risen while resources have decreased since 2022 when Winter Storm Elliot caused energy emergencies in PJM and surrounding areas. Risk Scenario Summary Expected resources meet operating reserve requirements under the assessed normal and extreme scenarios. Generator outages on a level of those experienced during Winter Storm Elliot would lead to energy emergencies.	On-Peak Reserve Margin  ■ Anticipated Reserve Margin ■ Prospective Reserve Margin — Reference Margin Level
On-Peak Fuel Mix 	2023–2024 Winter Risk Period Scenario  Scenario Description (See Data Concepts and Assumptions) Risk Period: Highest risk for unserved energy at peak demand hour Demand Scenarios: Net internal demand (50/50) and (90/10) demand forecast Forced Outages: Based on historical data and trending Extreme Derates: Accounts for reduced thermal capacity contributions due to performance in extreme conditions Elliott-level Outages: Additional forced outages equal to the total MW capacity on outage due to freezing and fuel issues during winter storm Elliott in 2022. Operational Mitigations: A total of 0.8 GW based on operational/emergency procedures * See PJM Report <i>Winter Storm Elliott Event Analysis and Recommendations Report</i>, July 17, 2023, available here.

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	SERC-Central SERC-Central is an assessment area within the SERC Regional Entity. SERC-Central includes all of Tennessee and portions of Georgia, Alabama, Mississippi, Missouri, and Kentucky. Historically a summer-peaking area, SERC-Central is beginning to have higher peak demand forecasts in winter. SERC is one of the six Regional Entities across North America that is responsible for the work under FERC approved delegation agreements with NERC. SERC is specifically responsible for the reliability and security of the electric grid across the Southeastern and Central United States. The SERC Regional Entity area covers approximately 630,000 square miles with a population of more than 91 million. The SERC Regional Entity includes 36 BAs, 28 Planning Authorities (PA), and 6 RCs.																															
Highlights - Based on the projected non-coincident net peak demand forecast as well as existing and planned generation resources, the ARM for the SERC-Central assessment area is projected to exceed the 15% NERC Reference Reserve Margin. - While short-term issues (e.g., forced outages, colder than normal temperatures, or supply issues) around neighboring systems or natural gas pipelines are possibilities, the SERC-Central assessment area expects to maintain real-time operating reserves at all times. Therefore, SERC-Central does not anticipate any significant reliability issues because of fuel supply, inventory, or transportation. - SERC-Central has extensive weatherization processes that include developed procedures specific to freezing events. SERC-Central is prepared to respond to unanticipated operational events and coordinate with neighboring entities to promote overall system reliability.	On-Peak Reserve Margin  <table><tr><th>Year</th><th>Anticipated Reserve Margin</th><th>Prospective Reserve Margin</th><th>Reference Margin Level</th></tr><tr><td>2022-2023</td><td>~25%</td><td>~35%</td><td>15%</td></tr><tr><td>2023-2024</td><td>~30%</td><td>~35%</td><td>15%</td></tr></table> ■ Anticipated Reserve Margin ■ Prospective Reserve Margin — Reference Margin Level	Year	Anticipated Reserve Margin	Prospective Reserve Margin	Reference Margin Level	2022-2023	~25%	~35%	15%	2023-2024	~30%	~35%	15%																			
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On-Peak Fuel Mix  <table><tr><th>Fuel Type</th><th>Percentage</th></tr><tr><td>Nuclear</td><td>~15%</td></tr><tr><td>Pumped Storage</td><td>~2%</td></tr><tr><td>Conventional Hydro</td><td>~5%</td></tr><tr><td>Natural Gas</td><td>~45%</td></tr><tr><td>Coal</td><td>~33%</td></tr></table>	Fuel Type	Percentage	Nuclear	~15%	Pumped Storage	~2%	Conventional Hydro	~5%	Natural Gas	~45%	Coal	~33%	2023-2024 Winter Risk Period Scenario  <table><tr><th>Category</th><th>Value (GW)</th></tr><tr><td>Anticipated Resources</td><td>52.7</td></tr><tr><td>Typical Maintenance Outages</td><td>-0.7</td></tr><tr><td>Typical Forced Outages</td><td>-2.3</td></tr><tr><td>Elliott-level Outages</td><td>-7.1</td></tr><tr><td>Operational Mitigations</td><td>+0.04</td></tr><tr><td>Expected Total Operating Reserve + Extreme Peak Demand</td><td>46.9</td></tr><tr><td>Expected Operating Reserve Requirement</td><td>1.5</td></tr><tr><td>50/50 Demand</td><td>40.5</td></tr></table>	Category	Value (GW)	Anticipated Resources	52.7	Typical Maintenance Outages	-0.7	Typical Forced Outages	-2.3	Elliott-level Outages	-7.1	Operational Mitigations	+0.04	Expected Total Operating Reserve + Extreme Peak Demand	46.9	Expected Operating Reserve Requirement	1.5	50/50 Demand	40.5	Scenario Description (See Data Concepts and Assumptions) Risk Period: Highest risk for unserved energy at peak demand hour Demand Scenarios: Net internal demand (50/50) and (90/10) demand forecast using 30 years of historical data Maintenance Outages: Data collected through a survey of members for outages during December through February Forced Outages: Includes any weighted average forced outage rates on-peak that are not factored into the anticipated resources calculation Elliott-level Outages: Additional forced outages that, when added to the typical outage scenario, equal the total MW capacity on outage due to freezing and fuel issues during Winter Storm Elliott in 2022 Operational Mitigations: A total of 0.04 GW based on operational/emergency procedures
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		SERC-Southeast SERC-Southeast is a summer-peaking assessment area within the SERC Regional Entity. SERC-Southeast includes all or portions of Georgia, Alabama, and Mississippi. SERC is one of the six Regional Entities across North America that is responsible for the work under FERC approved delegation agreements with NERC. SERC is specifically responsible for the reliability and security of the electric grid across the Southeastern and Central United States. The SERC Regional Entity covers approximately 630,000 square miles with a population of more than 91 million. The SERC Regional Entity includes 36 BAs, 28 Planning Authorities (PA), and 6 RCs.																																					
Highlights - Based on the projected non-coincident net peak demand forecast as well as existing and planned generation resources, the ARM for the SERC-Southeast assessment area is projected to exceed the 15% NERC Reference Reserve Margin. - The entities do not anticipate any significant reliability issues because of fuel supply, inventory, or transportation. - Many entities have extensive weatherization processes that include developed procedures specific to freezing events. The entities are prepared to respond to unexpected, day-to-day events and coordinate with neighboring entities to promote overall system reliability.		On-Peak Reserve Margin  <table><caption>On-Peak Reserve Margin Data</caption><tr><th>Year</th><th>Anticipated Reserve Margin</th><th>Prospective Reserve Margin</th><th>Reference Margin Level</th></tr><tr><td>2022–2023</td><td>~32%</td><td>~38%</td><td>15%</td></tr><tr><td>2023–2024</td><td>~42%</td><td>~48%</td><td>15%</td></tr></table>		Year	Anticipated Reserve Margin	Prospective Reserve Margin	Reference Margin Level	2022–2023	~32%	~38%	15%	2023–2024	~42%	~48%	15%																								
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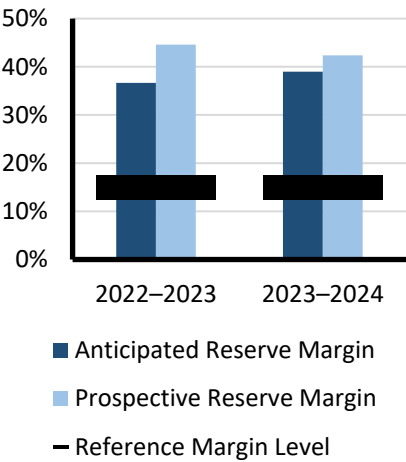
SERC-Florida Peninsula

SERC-Florida Peninsula is a summer-peaking assessment area within SERC. SERC is one of the six Regional Entities across North America that is responsible for the work under FERC approved delegation agreements with NERC. SERC is specifically responsible for the reliability and security of the electric grid across the Southeastern and Central United States. The SERC Regional Entity area covers approximately 630,000 square miles with a population of more than 91 million. The SERC Regional Entity includes 36 BAs, 28 Planning Authorities (PA), and 6 RCs.

Highlights

- Based on the projected non-coincident net peak demand forecast as well as existing and planned generation resources, the ARM for the SERC Florida-Peninsula assessment area is projected to exceed the 15% NERC Reference Reserve Margin.
- Although the entities do not currently anticipate reliability impacts in the upcoming winter season, some entities have expressed concerns about the difficulty of scheduling and receiving coal deliveries on a consistent basis, which would affect unit availability.
- The entities have performed a summary review of their winterization plans as well as the coordination of generation and transmission outages through the Florida Reliability Coordinating Council (FRCC) Operations PC and RC functions.

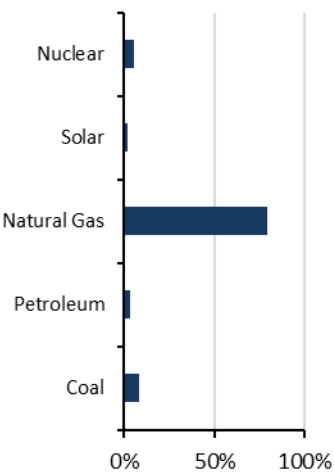
On-Peak Reserve Margin



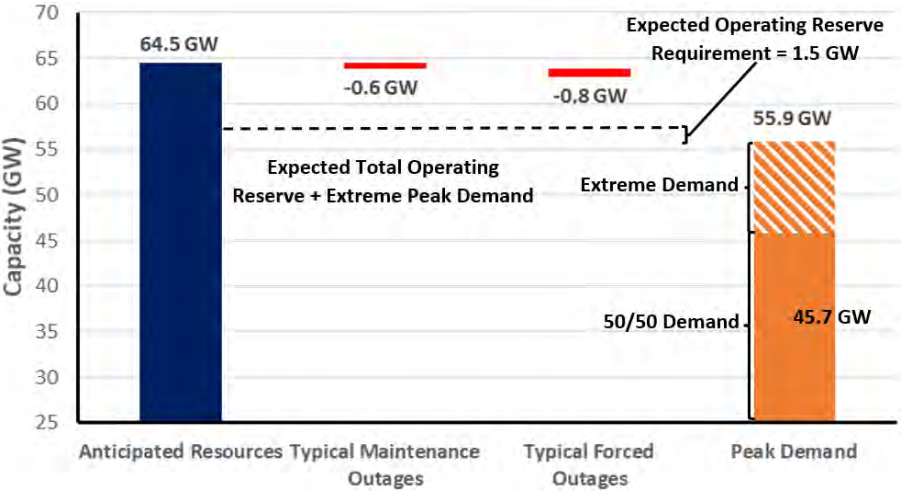
Risk Scenario Summary

Expected resources meet operating reserve requirements under the assessed scenarios.

On-Peak Fuel Mix



2023-2024 Winter Risk Period Scenario



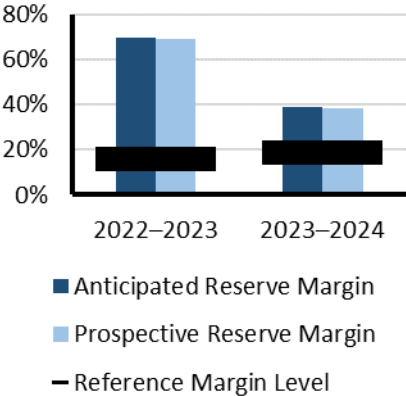
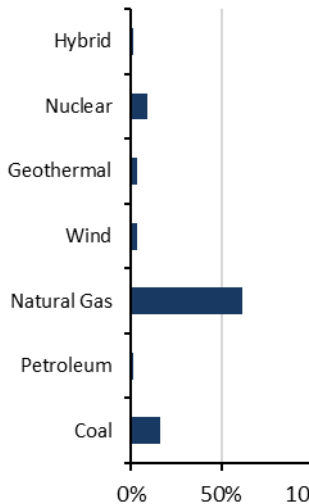
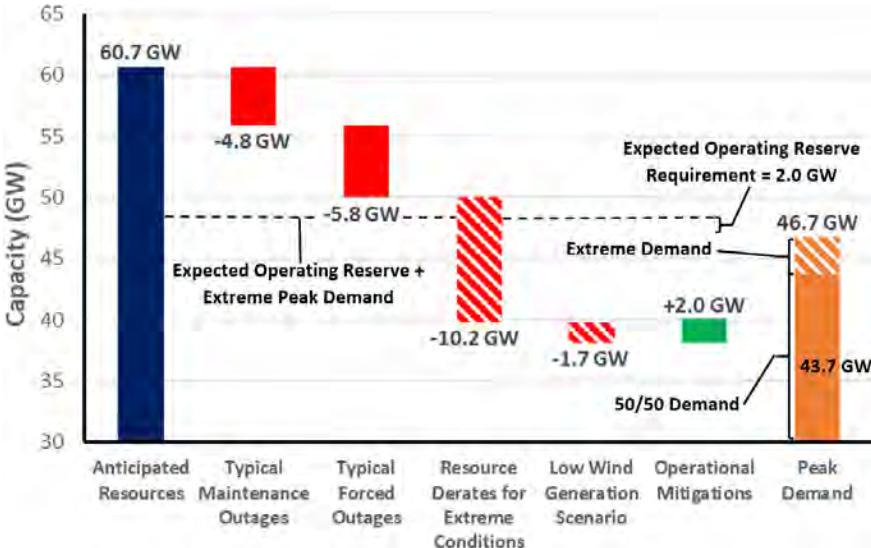
Scenario Description (See Data Concepts and Assumptions)

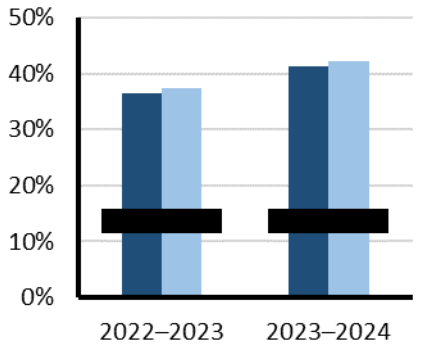
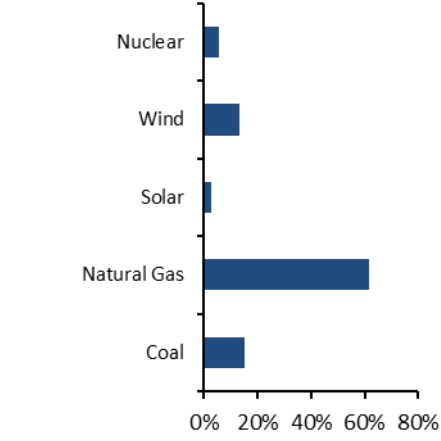
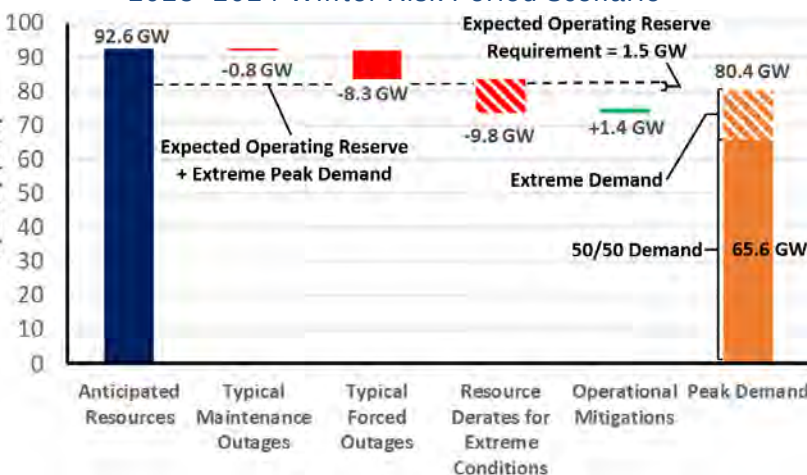
Risk Period: Highest risk for unserved energy at peak demand hour

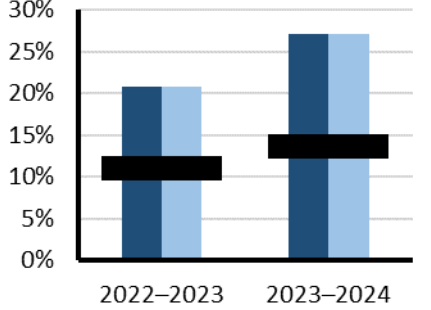
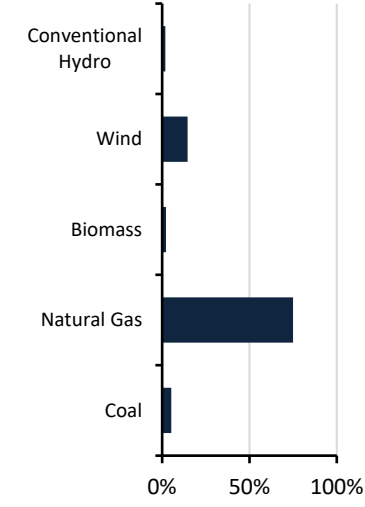
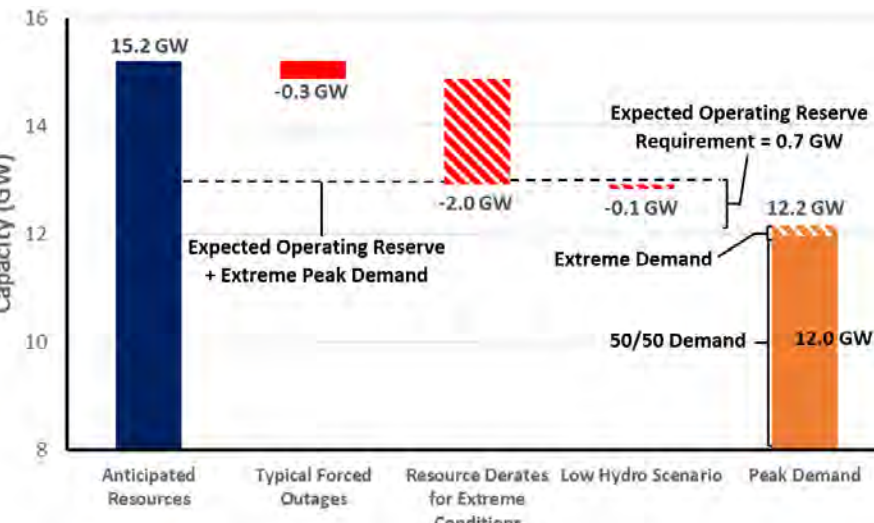
Demand Scenarios: Net internal demand (50/50) and (90/10) demand forecast using 30 years of historical data

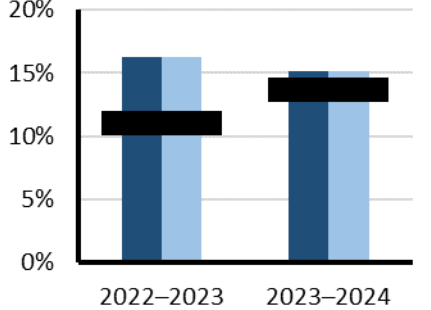
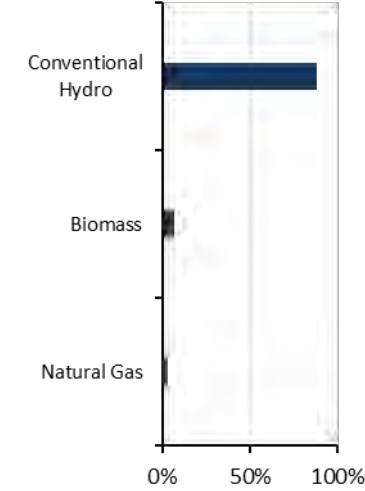
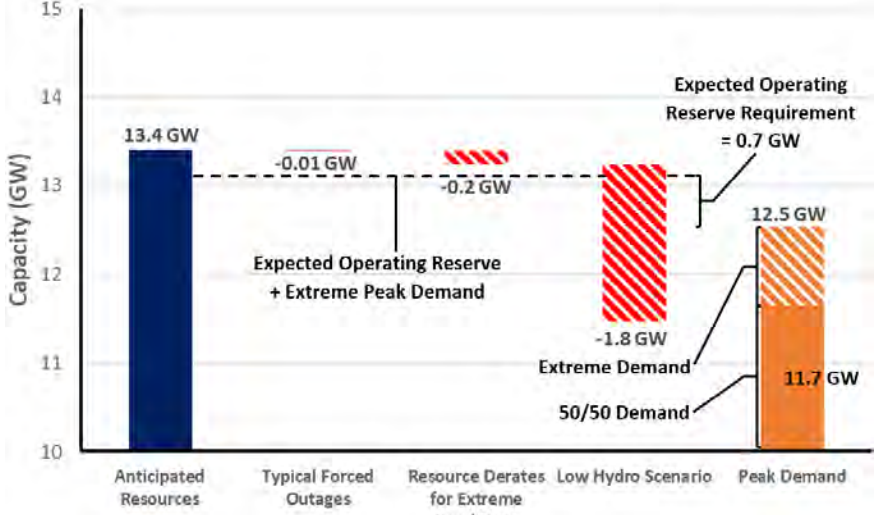
Maintenance Outages: Data collected through a survey of members for outages during December through February

Forced Outages: Weighted average forced outage rates on-peak are factored into the anticipated resources calculation

	SPP SPP PC footprint covers 546,000 square miles and encompasses all or parts of Arkansas, Iowa, Kansas, Louisiana, Minnesota, Missouri, Montana, Nebraska, New Mexico, North Dakota, Oklahoma, South Dakota, Texas, and Wyoming. The SPP long-term assessment is reported based on the PC footprint, which touches parts of the Midwest Reliability Organization Regional Entity and the WECC Regional Entity. The SPP assessment area footprint has approximately 61,000 miles of transmission lines, 756 generating plants, and 4,811 transmission-class substations, and serves a population of more than 18 million.																																		
Highlights - SPP anticipates that planning reserves are adequate for the upcoming winter season. Reserve margins have fallen this winter because of increased peak demand projections and declining anticipated resources. - SPP does not anticipate any emerging reliability issues impacting the area for the 2023–2024 winter season but realizes that interruptions to fuel supply could create unique operation challenges. - SPP continues to work with neighboring areas to address potential electricity deliverability issues associated with extreme weather events. Efforts are aimed at enhancing communications and operator preparedness. - To minimize conservative operations, EEAs, and the response to mid-range forecast error uncertainty in wind forecasts, SPP created some new mitigation processes to deal with high-impact areas of concern. SPP has developed operational mitigation teams, processes, and procedures that have been put in place to maintain real-time reliability needs. - SPP created a Resource and Energy Adequacy Leadership Team that is addressing numerous resource adequacy initiatives that are addressing an expected unserved energy (EUE) standard, fuel assurance, winter requirements, winter PRM, outage policies, demand response, accreditation, and other areas of impact. - SPP hosted its winter preparedness workshop in October 2023.	On-Peak Reserve Margin  <table><thead><tr><th>Period</th><th>Anticipated Reserve Margin</th><th>Prospective Reserve Margin</th><th>Reference Margin Level</th></tr></thead><tbody><tr><td>2022–2023</td><td>~70%</td><td>~70%</td><td>~20%</td></tr><tr><td>2023–2024</td><td>~40%</td><td>~40%</td><td>~20%</td></tr></tbody></table>	Period	Anticipated Reserve Margin	Prospective Reserve Margin	Reference Margin Level	2022–2023	~70%	~70%	~20%	2023–2024	~40%	~40%	~20%																						
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On-Peak Fuel Mix  <table><thead><tr><th>Fuel Source</th><th>Percentage</th></tr></thead><tbody><tr><td>Hybrid</td><td>~1%</td></tr><tr><td>Nuclear</td><td>~5%</td></tr><tr><td>Geothermal</td><td>~1%</td></tr><tr><td>Wind</td><td>~2%</td></tr><tr><td>Natural Gas</td><td>~55%</td></tr><tr><td>Petroleum</td><td>~1%</td></tr><tr><td>Coal</td><td>~10%</td></tr></tbody></table>	Fuel Source	Percentage	Hybrid	~1%	Nuclear	~5%	Geothermal	~1%	Wind	~2%	Natural Gas	~55%	Petroleum	~1%	Coal	~10%	2023–2024 Winter Risk Period Scenario  <table><thead><tr><th>Category</th><th>Value (GW)</th></tr></thead><tbody><tr><td>Anticipated Resources</td><td>60.7</td></tr><tr><td>Typical Maintenance Outages</td><td>-4.8</td></tr><tr><td>Typical Forced Outages</td><td>-5.8</td></tr><tr><td>Resource Derates for Extreme Conditions</td><td>-10.2</td></tr><tr><td>Low Wind Scenario</td><td>-1.7</td></tr><tr><td>Operational Mitigations</td><td>+2.0</td></tr><tr><td>50/50 Demand</td><td>43.7</td></tr><tr><td>Expected Operating Reserve Requirement</td><td>2.0</td></tr></tbody></table> Scenario Description (See Data Concepts and Assumptions) Risk Period: Highest risk for unserved energy at peak demand hour Demand Scenarios: Net internal demand (50/50) and extreme demand forecast using historical data Maintenance and Forced Outages: A capacity derate for maintenance outages, forced outages, and performance in extreme weather based on historical data Extreme Derates: A capacity derate for generator performance in extreme weather based on historical data Low Wind Scenario: 1.7 GW of wind potentially off-line when temperatures fall below their cold weather performance packages Operational Mitigations: A total of 2 GW based on operational/emergency procedures (External Assistance)	Category	Value (GW)	Anticipated Resources	60.7	Typical Maintenance Outages	-4.8	Typical Forced Outages	-5.8	Resource Derates for Extreme Conditions	-10.2	Low Wind Scenario	-1.7	Operational Mitigations	+2.0	50/50 Demand	43.7	Expected Operating Reserve Requirement	2.0
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	Texas RE-ERCOT ERCOT is the ISO for the ERCOT Interconnection and is located entirely in the state of Texas; it operates as a single BA. It also performs financial settlement for the competitive wholesale bulk-power market and administers retail switching for nearly 8 million premises in competitive choice areas. ERCOT is governed by a board of directors and subject to oversight by the Public Utility Commission of Texas and the Texas Legislature. ERCOT is summer-peaking and covers approximately 200,000 square miles, connects over 52,700 miles of transmission lines, has over 1,100 generation units, and serves more than 26 million customers. Texas RE is responsible for the Regional Entity functions described in the Energy Policy Act of 2005 for ERCOT. On November 3, 2022, the Public Utility Commission of Texas issued an order directing ERCOT to assume the duties and responsibilities of the reliability monitor for the Texas power grid.
Highlights - For the upcoming winter season, Texas RE-ERCOT will face reserve shortage risks during high net load hours. In winter, solar generation is not available to serve peak demand, making the system dependent on wind generation and dispatchable resource availability to serve load. - Reserve scarcity risks are greater than last winter due primarily to robust load growth along with insufficient new dispatchable resources to serve the higher net peak loads. - The area has also experienced a large increase in thermal units planned to be indefinitely mothballed to operate under a summer-only availability schedule; a loss of 1,283 MW of winter-rated capacity is expected. - The risk of reserve shortages leading to EEA declarations has increased from “low” to “elevated” for hour-ending 8:00 a.m. based on ERCOT’s probabilistic risk assessment. ERCOT is investigating the option to procure additional capacity to reduce this reserve shortage risk on a competitive basis. - ERCOT does not expect any significant fuel supply issues for the winter. However, fuel-related outages during Winter Storm Elliott (December 22–25, 2023) indicated that natural gas-fired generators that normally experience fuel restrictions during cold weather are expected to continue to face such restrictions. ERCOT’s new Firm Fuel Supply Service was deployed during this storm and is expected to partially offset the lost generation capacity due to these natural gas restrictions. - ERCOT has observed increasing transmission congestion from South Texas to South-Central Texas (including the San Antonio area) that will limit transfers during the winter. A transmission project that includes a new 345 kV double circuit transmission line was recommended with an expected in-service date of June 2027 to address this congestion.	On-Peak Reserve Margin 
Risk Scenario Summary Expected resources meet operating reserve requirements under normal peak-demand scenarios. Above-normal winter peak load and outage conditions could result in the need to employ operating mitigations (i.e., demand response and transfers) and EEAs. Load shedding is unlikely but may be needed under wide-area cold weather events.	
On-Peak Fuel Mix 	2023–2024 Winter Risk Period Scenario  Scenario Description (See Data Concepts and Assumptions) Risk Period: Highest risk for unserved energy at peak demand hour Demand Scenarios: Net internal demand (50/50) and extreme winter peak demand based on 2020–2021 Winter Storm Uri peak demand Maintenance Outages: Based on historical winter data and consideration of ERCOT’s allowed maximum system daily planned outage capacity Forced Outages: Based on the historical averages of maintenance or forced outages respectively for December through February weekdays, hours ending 7:00–10:00 a.m. local time for the last three (2020/2021, 2021/2022, and 2022/2023) winter seasons (Winter Storm Uri-related forced outages between February 15–18, 2021, were excluded from this calculation.) Extreme Derates: Accounts for reduced thermal, wind, and solar PV capacity contributions due to performance in extreme conditions (uses averages from Winter Storm URI with adjustments to account for implemented weatherization improvements) Operational Mitigations: Additional potential capacity from switchable generation and imports

	WECC-Alberta WECC-Alberta is a winter-peaking assessment area in the WECC Regional Entity that consists of the province of Alberta, Canada. WECC is responsible for coordinating and promoting BES reliability across the entire Western Interconnection. WECC is geographically the largest and most diverse Regional Entity serving an area of nearly 1.8 million square miles and more than 82 million customers. The WECC Regional Entity area includes the provinces of Alberta and British Columbia in Canada, the northern portion of Baja California in Mexico as well as all or portions of 14 western U.S. states in between. WECC’s 329 members include 39 BAs, representing a wide spectrum of organizations with an interest in the BES.	
Highlights - WECC-Alberta shows some risk highlighted by the risk period scenario; however, the area is expected to be able to be covered through imports if not islanded. - WECC- Alberta’s operating reserve margins are met before imports in all scenarios except the Low Wind Scenario, which leaves a gap of 0.5 GW, and the Extreme Combined Scenario, which leaves a gap of 1.0 GW under extreme peak demand conditions. Both of these scenarios are anticipated to be able to be covered through imports. WECC-Alberta is a winter-peaking area and did see a few EEA-3s last season due to a combination of extreme demand peaks from cold temperatures, low wind, and the loss of a baseload unit.		On-Peak Reserve Margin  2022–2023 2023–2024 ■ Anticipated Reserve Margin ■ Prospective Reserve Margin — Reference Margin Level
Risk Scenario Summary Expected resources meet operating reserve requirements under normal peak-demand scenarios. Above-normal winter peak load and outage conditions could result in the need to employ operating mitigations (i.e., demand response and transfers) and EEAs. Load shedding is unlikely but may be needed under wide-area cold weather events.		
On-Peak Fuel Mix 	2023–2024 Winter Risk Period Scenario 	Scenario Description (See Data Concepts and Assumptions) Risk Period: Highest risk for unserved energy at peak demand hour Demand Scenarios: Net internal demand (50/50) and (90/10) demand forecast Forced Outages: Calculated using (90/10) scenario Extreme Derates: Resources derates based on (90/10) scenario Low Hydro Scenario: Estimated derate for lower hydro output

	WECC-British Columbia WECC-British Columbia is a winter-peaking assessment area in the WECC Regional Entity that consists of the province of British Columbia, Canada. WECC is responsible for coordinating and promoting BES reliability across the entire Western Interconnection. WECC is geographically the largest and most diverse Regional Entity serving an area of nearly 1.8 million square miles and more than 82 million customers. The WECC Regional Entity area includes the provinces of Alberta and British Columbia in Canada, the northern portion of Baja California in Mexico as well as all or portions of 14 western US states in between. WECC’s 329 members include 39 BAs, representing a wide spectrum of organizations with an interest in the BES.	
Highlights - WECC-British Columbia has adequate resources for anticipated winter conditions. If peak demand exceeds normal forecasts or hydroelectric generation is lower than normal, non-firm imports may be needed to meet required operating reserves. - WECC-British Columbia could require a range of import levels for extreme demand or low-resource scenarios. For expected demand, the area falls short of its operating reserve requirements if hydro output is abnormally low (low likelihood scenario). During the Extreme Peak Demand Scenario (90th percentile), operating reserve margins fall short by 0.6 GW with anticipated resources and could increase for more extreme outages or low-hydro scenarios. Sufficient imports from neighbors in the Western Interconnection are expected to be available, provided that BC does not become electrically islanded.		On-Peak Reserve Margin  2022–2023 2023–2024 - Anticipated Reserve Margin - Prospective Reserve Margin - Reference Margin Level
Risk Scenario Summary Expected resources meet operating reserve requirements under normal peak-demand scenarios. Above-normal winter peak load and outage conditions could result in the need to employ operating mitigations (i.e., demand response and transfers) and EEAs. Load shedding is unlikely but may be needed under wide-area cold weather events.		
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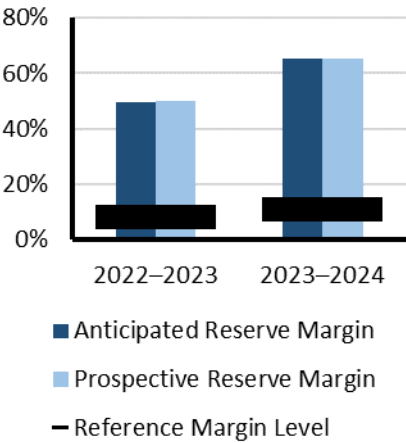
WECC-California/Mexico

WECC-California/Mexico is a summer-peaking assessment area in the WECC Regional Entity that includes parts of California, Nevada, and Baja California, Mexico. WECC is responsible for coordinating and promoting BES reliability across the entire Western Interconnection. WECC is geographically the largest and most diverse Regional Entity serving an area of nearly 1.8 million square miles and more than 82 million customers. The WECC Regional Entity area includes the provinces of Alberta and British Columbia in Canada, the northern portion of Baja California in Mexico as well as all or portions of 14 western US states in between. WECC’s 329 members include 39 BAs, representing a wide spectrum of organizations with an interest in the BES.

Highlights

- WECC-California/Mexico shows adequate energy availability under both expected and extreme scenarios.

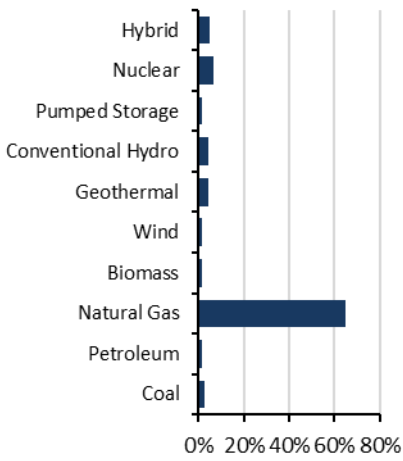
On-Peak Reserve Margin



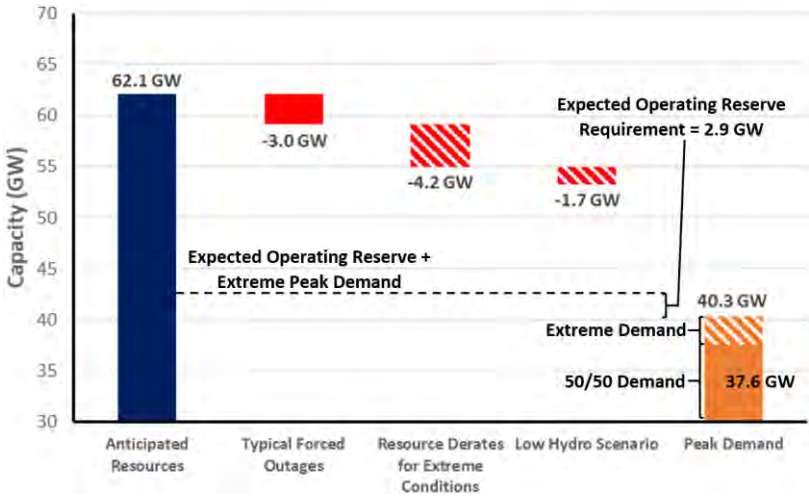
Risk Scenario Summary

Expected resources meet operating reserve requirements under the assessed scenarios.

On-Peak Fuel Mix



2023-2024 Winter Risk Period Scenario



Scenario Description (See Data Concepts and Assumptions)

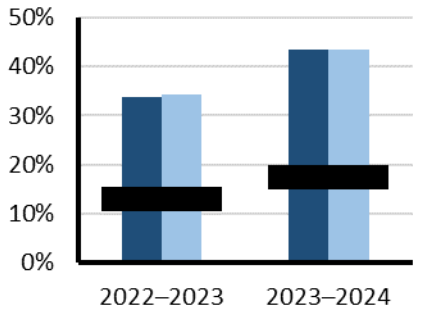
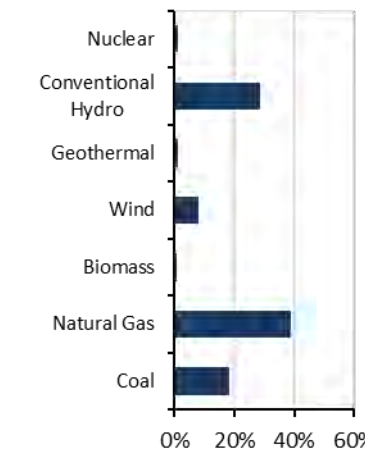
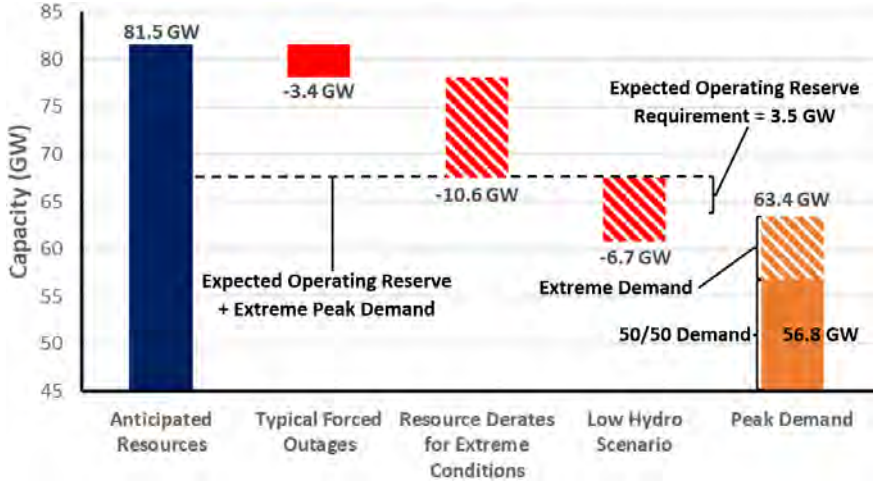
Risk Period: Highest risk for unserved energy at peak demand hour

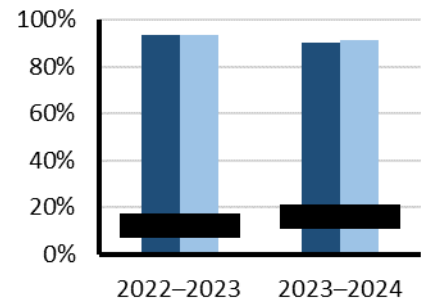
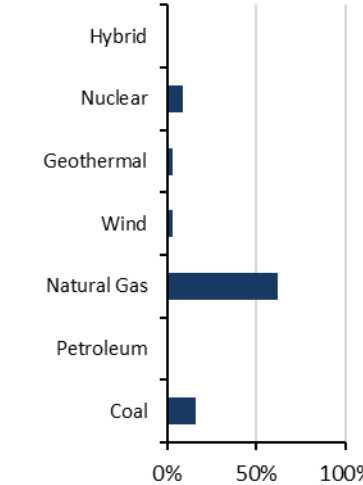
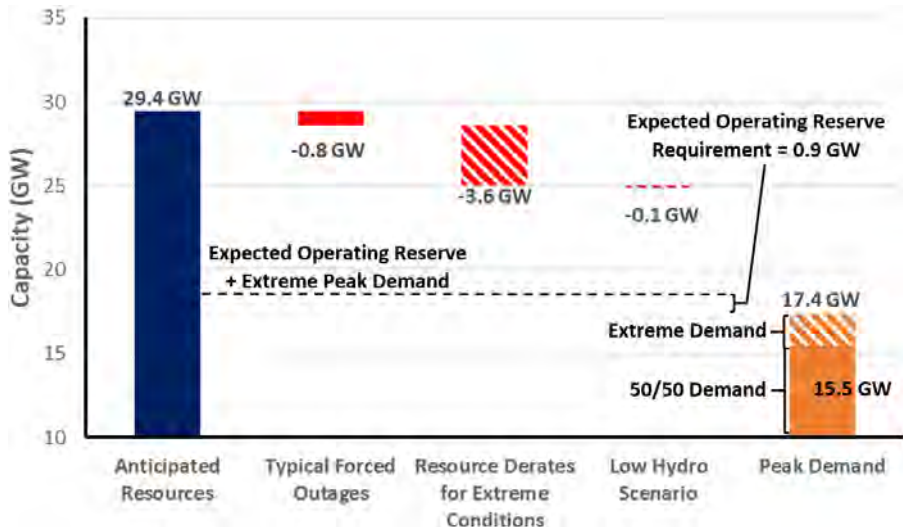
Demand Scenarios: Net internal demand (50/50) and (90/10) demand forecast

Forced Outages: Calculated using (90/10) scenario

Extreme Derates: Resources derates based on (90/10) scenario

Low Hydro Scenario: Estimated derate for lower hydro output

	WECC-Northwest WECC-Northwest is a summer-peaking assessment area in the WECC Regional Entity that includes Colorado, Idaho, Montana, Oregon, Utah, Washington, Wyoming and parts of California, Nebraska, Nevada, and South Dakota. WECC is responsible for coordinating and promoting BES reliability across the entire Western Interconnection. WECC is geographically the largest and most diverse Regional Entity serving an area of nearly 1.8 million square miles and more than 82 million customers. The WECC Regional Entity area includes the provinces of Alberta and British Columbia in Canada, the northern portion of Baja California in Mexico as well as all or portions of 14 western US states in between. WECC’s 329 members include 39 BAs, representing a wide spectrum of organizations with an interest in the BES.	
Highlights - WECC-Northwest shows some risk highlighted by the risk period scenario; however, the area is expected to be able to be covered through imports. - WECC-Northwest has historically been a mixed-season peaking area. Operating reserve margins are met at the expected peak demand hour under all but the Extreme Combined Scenario, where 5.3 GW of imports would be needed to meet operating reserve margins at an expected peak demand (50th percentile) and 10 GW for an extreme peak load level (90th percentile). Depending on the situation in neighboring areas, imports are expected to be available to fill the gap.		On-Peak Reserve Margin  2022–2023 2023–2024 ■ Anticipated Reserve Margin ■ Prospective Reserve Margin — Reference Margin Level
Risk Scenario Summary Expected resources meet operating reserve requirements under normal peak-demand scenarios. Above-normal winter peak load and outage conditions could result in the need to employ operating mitigations (i.e., demand response and transfers) and EEAs. Load shedding is unlikely but may be needed under wide-area cold weather events.		
On-Peak Fuel Mix  0% 20% 40% 60%	2023–2024 Winter Risk Period Scenario  Capacity (GW) 81.5 GW -3.4 GW -10.6 GW -6.7 GW Expected Operating Reserve Requirement = 3.5 GW Expected Operating Reserve + Extreme Peak Demand Extreme Demand 50/50 Demand 63.4 GW 56.8 GW Anticipated Resources Typical Forced Outages Resource Derates for Extreme Conditions Low Hydro Scenario Peak Demand	Scenario Description (See Data Concepts and Assumptions) Risk Period: Highest risk for unserved energy at peak demand hour Demand Scenarios: Net internal demand (50/50) and (90/10) demand forecast Forced Outages: Calculated using (90/10) scenario Extreme Derates: Resources derates based on (90/10) scenario Low Hydro Scenario: Estimated derate for lower hydro output

	WECC-Southwest WECC-Southwest is a summer-peaking assessment area in the WECC Regional Entity that includes Arizona, New Mexico, and part of California and Texas. WECC is responsible for coordinating and promoting BES reliability across the entire Western Interconnection. WECC is geographically the largest and most diverse Regional Entity serving an area of nearly 1.8 million square miles and more than 82 million customers. The WECC Regional Entity area includes the provinces of Alberta and British Columbia in Canada, the northern portion of Baja California in Mexico as well as all or portions of 14 western US states in between. WECC’s 329 members include 39 BAs, representing a wide spectrum of organizations with an interest in the BES.																																		
Highlights WECC-Southwest shows adequate energy availability under both expected and extreme scenarios.		On-Peak Reserve Margin  <table><thead><tr><th>Year</th><th>Anticipated Reserve Margin (%)</th><th>Prospective Reserve Margin (%)</th><th>Reference Margin Level (%)</th></tr></thead><tbody><tr><td>2022–2023</td><td>~95%</td><td>~95%</td><td>20%</td></tr><tr><td>2023–2024</td><td>~95%</td><td>~95%</td><td>20%</td></tr></tbody></table>		Year	Anticipated Reserve Margin (%)	Prospective Reserve Margin (%)	Reference Margin Level (%)	2022–2023	~95%	~95%	20%	2023–2024	~95%	~95%	20%																				
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Data Concepts and Assumptions

The table below explains data concepts and important assumptions used throughout this assessment.

General Assumptions
The reliability of the interconnected BPS is comprised of both adequacy and operating reliability:
- Adequacy is the ability of the electricity system to supply the aggregate electric power and energy requirements of consumers at all times while taking into account scheduled and reasonably expected unscheduled outages of system components.
- Operating reliability is the ability of the electricity system to withstand sudden disturbances, such as electric short-circuits or unanticipated loss of system components.
The reserve margin calculation is an important industry planning metric used to examine future resource adequacy.
All data in this assessment is based on existing federal, state, and provincial laws and regulations.
Differences in data collection periods for each assessment area should be considered when comparing demand and capacity data between year-to-year seasonal assessments.
2023 Long-Term Reliability Assessment data has been used for most of this 2023–2024 assessment period augmented by updated load and capacity data provided by Regional Entities and assessment areas.
A positive net transfer capability would indicate a net-importing assessment area, a negative value would indicate a net exporter.
Demand Assumptions
Electricity demand projections, or load forecasts, are provided by each assessment area.
Load forecasts include peak hourly load⁵ or total internal demand for the summer and winter of each year.⁶
Total internal demand projections are based on normal weather (50/50 distribution⁷) and are provided on a coincident⁸ basis for most assessment areas.
Net internal demand is used in all reserve margin calculations, and it is equal to total internal demand then reduced by the amount of controllable and dispatchable demand response projected to be available during the peak hour.
Resource Assumptions
Resource planning methods vary throughout the North American BPS. NERC uses the categories below to provide a consistent approach for collecting and presenting resource adequacy. Because the electrical output of variable energy resources (e.g., wind, solar) depends on weather conditions, their contribution to reserve margins and other on-peak resource adequacy analysis is less than their nameplate capacity.

⁵ [Glossary of Terms](#) used in NERC Reliability Standards

⁶ The summer season represents June–September and the winter season represents December–February.

⁷ Essentially, this means that there is a 50% probability that actual demand will be higher and a 50% probability that actual demand will be lower than the value provided for a given season/year.

⁸ Coincident: This is the sum of two or more peak loads that occur in the same hour. Noncoincident: This is the sum of two or more peak loads on individual systems that do not occur in the same time interval; this is meaningful only when considering loads within a limited period of time, such as a day, a week, a month, a heating or cooling season, and usually for not more than one year. SERC and FRCC calculate total internal demand on a noncoincidental basis.

<u>Anticipated Resources:</u> • Existing-Certain Capacity: Included in this category are commercially operable generating unit or portions of generating units that meet at least one of the following requirements when examining the period of peak demand for the winter season: unit must have a firm capability and have a power purchase agreement with firm transmission that must be in effect for the unit; unit must be classified as a designated network resource; and/or where energy-only markets exist, unit must be a designated market resource eligible to bid into the market. • Tier 1 Capacity Additions: This category includes capacity that either is under construction or has received approved planning requirements. • Net Firm Capacity Transfers (Imports minus Exports): This category includes transfers with firm contracts.
<u>Prospective Resources:</u> This includes all anticipated resources plus the following: Existing-Other Capacity: Included in this category are commercially operable generating units or portions of generating units that could be available to serve load for the period of peak demand for the season but do not meet the requirements of existing-certain.
Reserve Margin Descriptions
Planning Reserve Margin: This is the primary metric used to measure resource adequacy; it is defined as the difference in resources (anticipated or prospective) and net internal demand then divided by net internal demand and shown as a percentage.
Reference Margin Level: The assumptions and naming convention of this metric vary by assessment area. The Reference Margin Level can be determined using both deterministic and probabilistic (based on a 0.1/year loss of load study) approaches. In both cases, this metric is used by system planners to quantify the amount of reserve capacity in the system above the forecasted peak demand that is needed to ensure sufficient supply to meet peak loads. Establishing a Reference Margin Level is necessary to account for long-term factors of uncertainty involved in system planning, such as unexpected generator outages and extreme weather impacts that could lead to increase demand beyond what was projected in the 50/50 load forecasted. In many assessment areas, a Reference Margin Level is established by a state, provincial authority, ISO/RTO, or other regulatory body. In some cases, the Reference Margin Level is a requirement. Reference Margin Levels may be different for the summer and winter seasons. If a Reference Margin Level is not provided by an assessment area, NERC applies 15% for predominately thermal systems and 10% for predominately hydro systems.
Seasonal Risk Scenario Chart Description Each assessment area performed an operational risk analysis that was used to produce the seasonal risk scenario charts in the Regional Assessments Dashboards. The chart presents deterministic scenarios for further analysis of different resource and demand levels: The left blue column shows anticipated resources (from the resource adequacy data table), and the two orange columns at the right show the two demand scenarios of the normal peak net internal demand from the resource adequacy data table and the extreme winter peak demand—both determined by the assessment area. The middle red or green bars show adjustments that are applied cumulatively to the anticipated resources, such as the following: • Reductions for typical generation outages (i.e., maintenance and forced, not already accounted for in anticipated resources) • Reductions that represent additional outage or performance derating by resource type for extreme, low-probability conditions (e.g., drought condition impacts on hydroelectric generation, low-wind scenario affecting wind generation, fuel supply limitations, or extreme temperature conditions that result in reduced thermal generation output) • Additional capacity resources that represent quantified capacity from operational procedures, if any, that are made available during scarcity conditions Not all assessment areas have the same categories of adjustments to anticipated resources. Furthermore, each assessment area determined the adjustments to capacity based on methods or assumptions that are summarized below the chart. Methods and assumptions differ by assessment area and may not be comparable. The chart enables evaluation of resource levels against levels of expected operating reserve requirement and the forecasted demand. Furthermore, the effects from extreme events can also be examined by comparing resource levels after applying extreme scenario derates and/or extreme winter peak demand.

Resource Adequacy

The ARM, which is based on available resource capacity, is a metric used to evaluate resource adequacy by comparing the projected capability of anticipated resources to serve forecast peak demand.⁹ Large year-to-year changes in anticipated resources or forecast peak demand (net internal demand) can greatly impact Planning Reserve Margin calculations. NPCC-Maritimes marginally does not meet their RML for the upcoming winter. Other than NPCC-Maritimes, all assessment areas have sufficient ARMs to meet or exceed their Reference Margin Level for the 2023 winter as shown in [Figure 4](#).

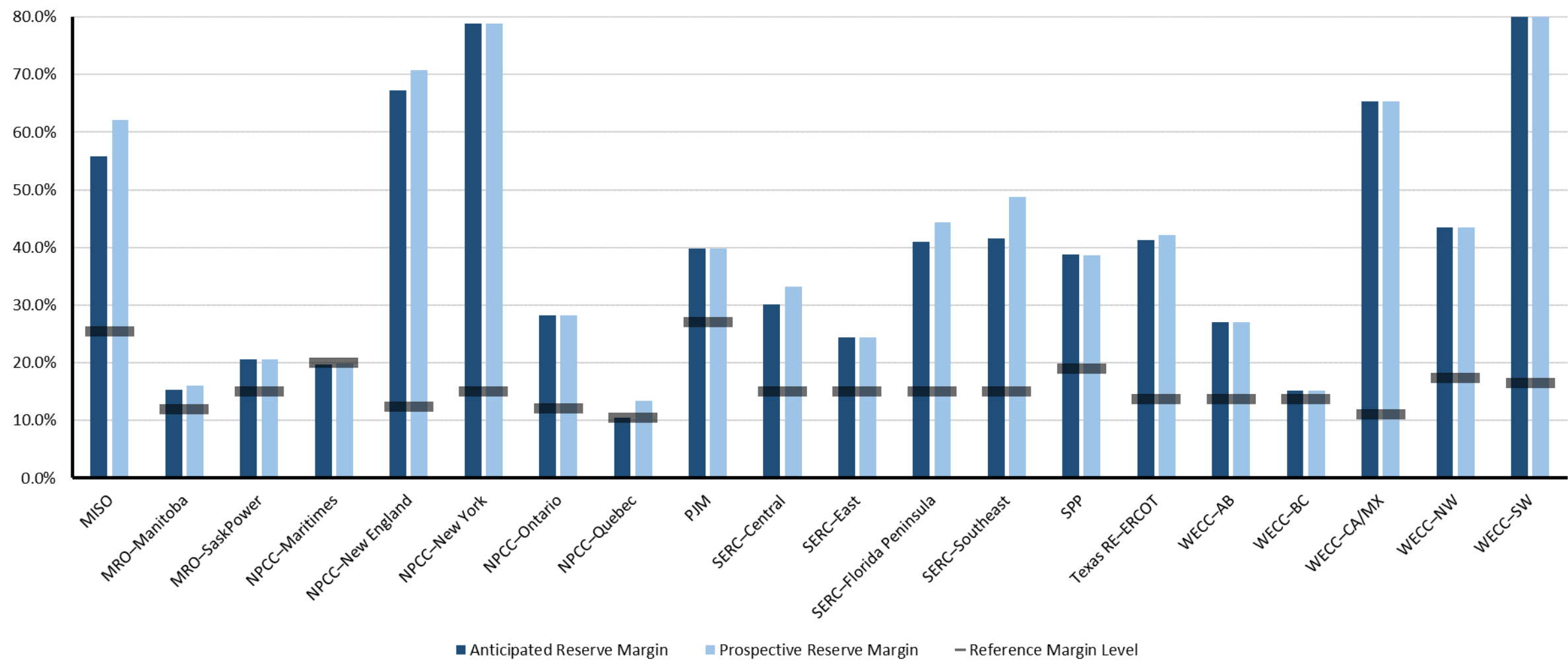


Figure 4: Winter 2023–2024 Anticipated/Prospective Reserve Margins Compared to Reference Margin Level

⁹ Generally, anticipated resources include generators and firm capacity transfers that are expected to be available to serve load during electrical peak loads for the season. Prospective resources are those that could be available but do not meet criteria to be counted as anticipated resources. Refer to the [Data Concepts and Assumptions](#) section for additional information on Anticipated/Prospective Reserve Margins, anticipated/prospective resources, and Reference Margin Levels.

Changes from Year-to-Year

Figure 5 provides the relative change in the forecast Anticipated Reserve Margins (ARM) from the 2022–2023 winter to the 2023–2024 winter. Note that the Reference Margin Level is unchanged for areas that don’t have a 2022–2023 Reference Margin Level shown. A significant decline can indicate potential operational issues that emerge between reporting years. MRO-Manitoba, MRO-SaskPower, NPCC-Québec, and WECC-BC have noticeable reductions in anticipated resources between the 2022–2023 winter and the 2023–2024 winter. All areas except NPCC-Maritimes remain above their Reference Margin Levels for 2023–2024 winter. NPCC-Québec is marginally above its Reference Margin Level. The lower ARMs for MRO-Manitoba, MRO-SaskPower, NPCC-Québec, and WECC-BC do not result in reliability concerns during expected conditions for this upcoming winter. The Canadian winter-peaking systems of MRO-Manitoba, MRO-SaskPower, NPCC-Maritimes and NPCC-Québec have reserve margins that are near Reference Margin Levels but are unlikely to experience high outage rates from their winterized generators. Additional details are provided in the [Data Concepts and Assumptions](#) section.

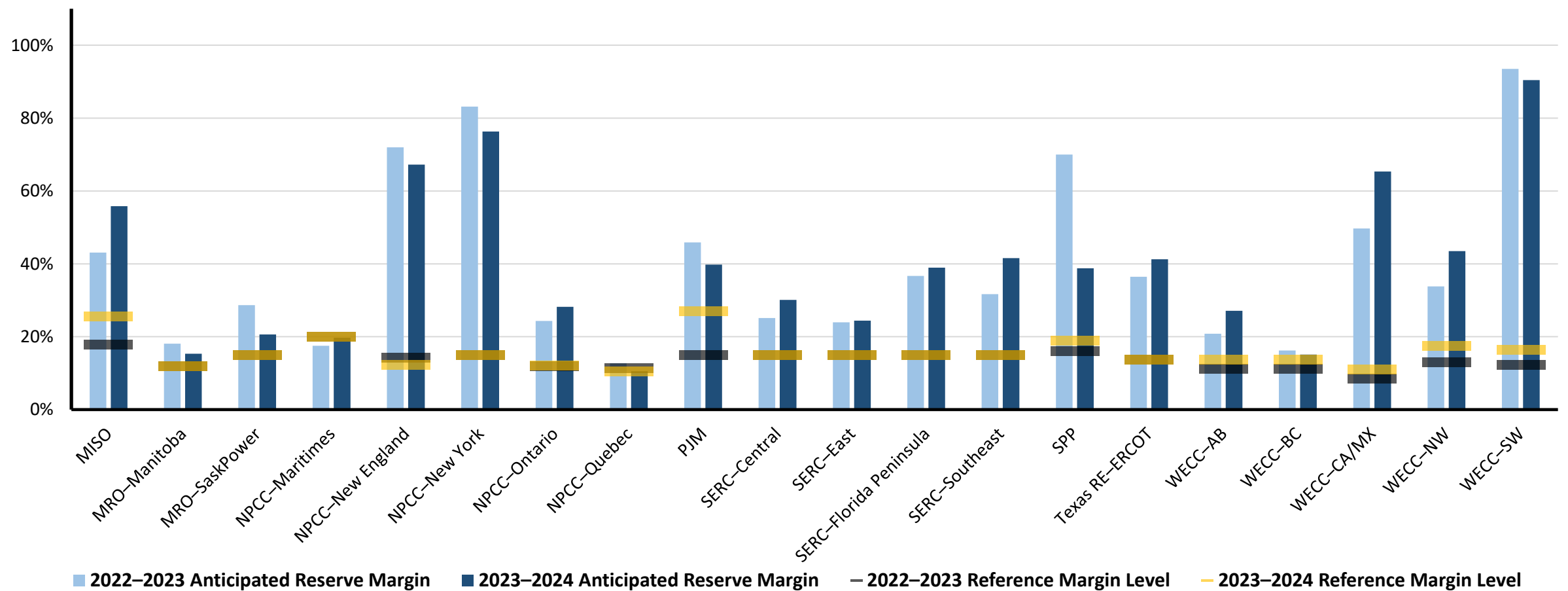


Figure 5: Winter 2022–2023 and Winter 2023–2024 Anticipated Reserve Margins Year-to-Year Change

Net Internal Demand

The changes in forecasted Net Internal Demand for each assessment area are shown in Figure 6.¹⁰ Assessment areas develop these forecasts based on historic load and weather information as well as other long-term projections. Most assessment areas are showing increasing demand for the upcoming winter compared with the last WRA.

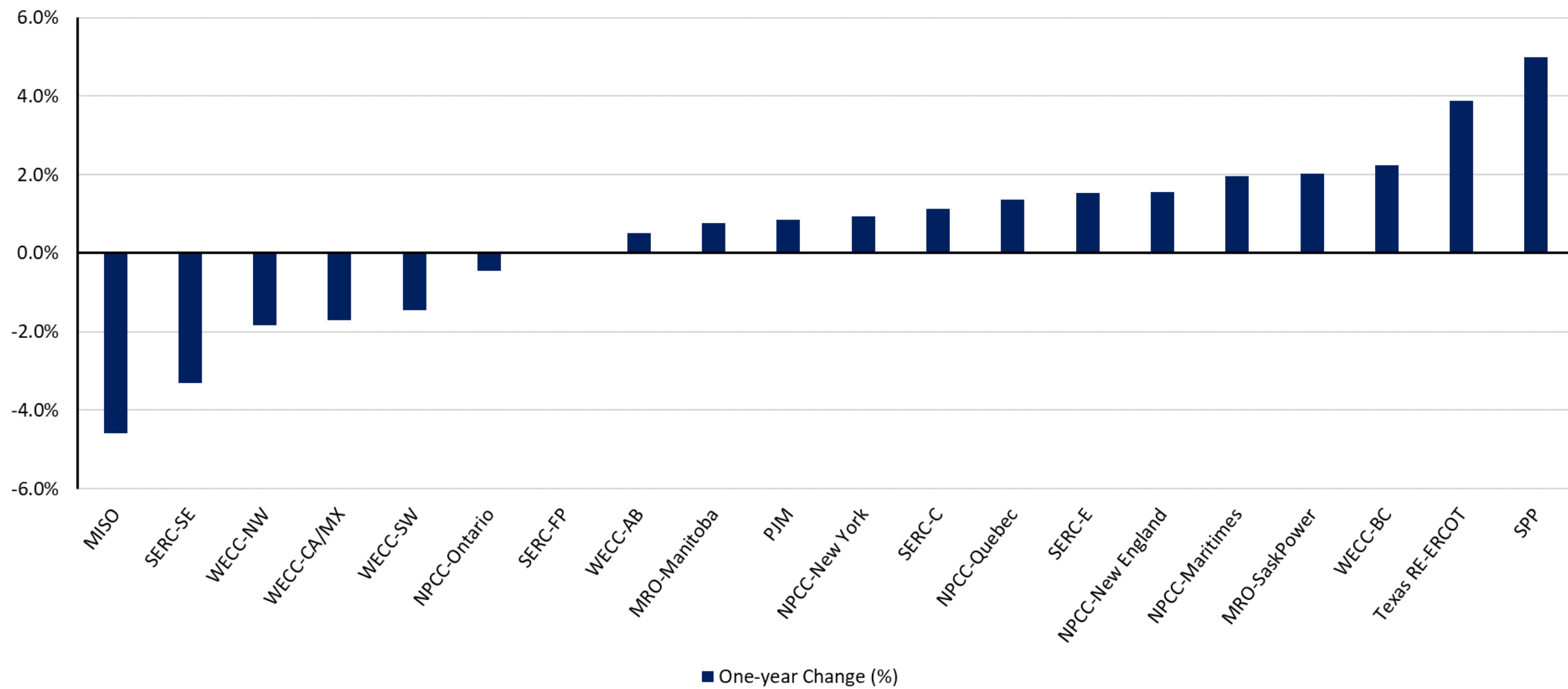


Figure 6: Change in Net Internal Demand—Winter 2022–2023 Forecast Compared to Winter 2023–2024 Forecast

¹⁰ Changes in modeling and methods may also contribute to year-to-year changes in forecasted net internal demand projections.

Demand and Resource Tables

Peak demand and supply capacity data (i.e., resource adequacy data) for each assessment area are as follows in each table (in alphabetical order).

MISO			
Demand, Resource, and Reserve Margins	2022–2023 WRA	2023–2024 WRA	2022–2023 vs. 2023–2024
Demand Projections	MW	MW	Net Change (%)
Total Internal Demand (50/50)	102,611	102,075	0.5%
Demand Response: Available	3,672	7,681	109.2%
Net Internal Demand	98,939	94,394	-4.6%
Resource Projections	MW	MW	Net Change (%)
Existing-Certain Capacity	137,926	146,976	6.6%
Tier 1 Planned Capacity	0	0	-
Net Firm Capacity Transfers	1,352	121	91.1%
Anticipated Resources	141,565	147,097	3.9%
Existing-Other Capacity	669	2,614	290.8%
Prospective Resources	148,125	153,003	3.3%
Reserve Margins	Percent (%)	Percent (%)	Annual Difference
Anticipated Reserve Margin	43.1%	55.8%	12.7
Prospective Reserve Margin	49.7%	62.1%	12.4
Reference Margin Level	17.9%	25.5%	7.6

MRO-SaskPower			
Demand, Resource, and Reserve Margins	2022–2023 WRA	2023–2024 WRA	2022–2023 vs. 2023–2024
Demand Projections	MW	MW	Net Change (%)
Total Internal Demand (50/50)	3,781	3,839	1.5%
Demand Response: Available	67	50	-25.4%
Net Internal Demand	3,714	3,789	2.0%
Resource Projections	MW	MW	Net Change (%)
Existing-Certain Capacity	4,488	4,320	-3.8%
Tier 1 Planned Capacity	0	0	-
Net Firm Capacity Transfers	290	250	-13.8%
Anticipated Resources	4,778	4,570	-4.4%
Existing-Other Capacity	0	0	-
Prospective Resources	4,778	4,570	-4.4%
Reserve Margins	Percent (%)	Percent (%)	Annual Difference
Anticipated Reserve Margin	28.7%	20.6%	-8.1
Prospective Reserve Margin	28.7%	20.6%	-8.1
Reference Margin Level	15.0%	15.0%	0.0

MRO-Manitoba Hydro			
Demand, Resource, and Reserve Margins	2022–2023 WRA	2023–2024 WRA	2022–2023 vs. 2023–2024
Demand Projections	MW	MW	Net Change (%)
Total Internal Demand (50/50)	4,588	4,623	0.8%
Demand Response: Available	0	0	-
Net Internal Demand	4,588	4,623	0.8%
Resource Projections	MW	MW	Net Change (%)
Existing-Certain Capacity	5,705	5,864	2.8%
Tier 1 Planned Capacity	279	90	-67.8%
Net Firm Capacity Transfers	-566	-622	9.9%
Anticipated Resources	5,418	5,332	-1.6%
Existing-Other Capacity	33	36	9.5%
Prospective Resources	5,451	5,368	-1.5%
Reserve Margins	Percent (%)	Percent (%)	Annual Difference
Anticipated Reserve Margin	18.1%	15.3%	-2.8
Prospective Reserve Margin	18.8%	16.1%	-2.7
Reference Margin Level	12.0%	12.0%	0.0

NPCC-Maritimes			
Demand, Resource, and Reserve Margins	2022–2023 WRA	2023–2024 WRA	2022–2023 vs. 2023–2024
Demand Projections	MW	MW	Net Change (%)
Total Internal Demand (50/50)	5,784	5,863	1.4%
Demand Response: Available	282	264	-6.4
Net Internal Demand	5,502	5,599	1.8%
Resource Projections	MW	MW	Net Change (%)
Existing-Certain Capacity	6,461	6,622	2.5%
Tier 1 Planned Capacity	0	0	-
Net Firm Capacity Transfers	4	81	1925.0%
Anticipated Resources	6,465	6,703	3.7%
Existing-Other Capacity	0	0	-
Prospective Resources	6,465	6,703	3.7%
Reserve Margins	Percent (%)	Percent (%)	Annual Difference
Anticipated Reserve Margin	17.5%	19.7%	2.2
Prospective Reserve Margin	17.5%	19.7%	2.2
Reference Margin Level	20.0%	20.0%	0.0

NPCC-New England			
Demand, Resource, and Reserve Margins	2022–2023 WRA	2023–2024 WRA	2022–2023 vs. 2023–2024
Demand Projections	MW	MW	Net Change (%)
Total Internal Demand (50/50)	20,009	20,269	1.3%
Demand Response: Available	610	570	-6.6%
Net Internal Demand	19,399	19,699	1.5%
Resource Projections	MW	MW	Net Change (%)
Existing-Certain Capacity	32,129	31,795	-1.0%
Tier 1 Planned Capacity	162	187	15.2%
Net Firm Capacity Transfers	1,070	958	-10.5%
Anticipated Resources	33,361	32,940	-1.3%
Existing-Other Capacity	142	201	42.1%
Prospective Resources	33,769	33,641	-0.4%
Reserve Margins	Percent (%)	Percent (%)	Annual Difference
Anticipated Reserve Margin	72.0%	67.2%	-4.8
Prospective Reserve Margin	74.1%	70.8%	-3.3
Reference Margin Level	14.3%	12.3%	-2.0

NPCC-Ontario			
Demand, Resource, and Reserve Margins	2022–2023 WRA	2023–2024 WRA	2022–2023 vs. 2023–2024
Demand Projections	MW	MW	Net Change (%)
Total Internal Demand (50/50)	21,255	21,402	0.7%
Demand Response: Available	614	853	39.0%
Net Internal Demand	20,641	20,549	-0.4%
Resource Projections	MW	MW	Net Change (%)
Existing-Certain Capacity	26,051	26,301	1.0%
Tier 1 Planned Capacity	112	24	-78.6%
Net Firm Capacity Transfers	-500	17	-103.4%
Anticipated Resources	25,662	26,342	2.6%
Existing-Other Capacity	0	0	-
Prospective Resources	25,662	26,342	2.6%
Reserve Margins	Percent (%)	Percent (%)	Annual Difference
Anticipated Reserve Margin	24.3%	28.2%	3.9
Prospective Reserve Margin	24.3%	28.2%	3.9
Reference Margin Level	11.8%	12.0%	0.2

NPCC-New York			
Demand, Resource, and Reserve Margins	2022–2023 WRA	2023–2024 WRA	2022–2023 vs. 2023–2024
Demand Projections	MW	MW	Net Change (%)
Total Internal Demand (50/50)	23,893	24,220	1.4%
Demand Response: Available	695	803	15.5%
Net Internal Demand	23,198	23,417	0.9%
Resource Projections	MW	MW	Net Change (%)
Existing-Certain Capacity	40,393	39,697	-1.7%
Tier 1 Planned Capacity	0	0	-
Net Firm Capacity Transfers	2,097	1,589	-24.2%
Anticipated Resources	42,490	41,285	-2.8%
Existing-Other Capacity	0	0	-
Prospective Resources	42,490	41,285	--2.8%
Reserve Margins	Percent (%)	Percent (%)	Annual Difference
Anticipated Reserve Margin	83.2%	76.3%	-6.9
Prospective Reserve Margin	83.2%	76.3%	-6.9
Reference Margin Level	15.0%	15.0%	-4.6

NPCC-Québec			
Demand, Resource, and Reserve Margins	2022–2023 WRA	2023–2024 WRA	2022–2023 vs. 2023–2024
Demand Projections	MW	MW	Net Change (%)
Total Internal Demand (50/50)	39,699	40,642	2.4%
Demand Response: Available	2,759	2,914	5.6%
Net Internal Demand	37,217	37,728	1.4%
Resource Projections	MW	MW	Net Change (%)
Existing-Certain Capacity	42,113	42,423	0.7%
Tier 1 Planned Capacity	255	0	-100.0%
Net Firm Capacity Transfers	-417	-726	74.1%
Anticipated Resources	41,951	41,697	-0.6%
Existing-Other Capacity	0	0	-
Prospective Resources	43,051	42,797	-0.6%
Reserve Margins	Percent (%)	Percent (%)	Annual Difference
Anticipated Reserve Margin	12.7%	10.5%	-2.2
Prospective Reserve Margin	15.7%	13.4%	-2.3
Reference Margin Level	11.3%	10.5%	-0.8

PJM			
Demand, Resource, and Reserve Margins	2022–2023 WRA	2023–2024 WRA	2022–2023 vs. 2023–2024
Demand Projections	MW	MW	Net Change (%)
Total Internal Demand (50/50)	132,980	132,667	-0.2%
Demand Response: Available	6,583	5,189	-21.2%
Net Internal Demand	126,397	127,478	0.9%
Resource Projections	MW	MW	Net Change (%)
Existing-Certain Capacity	185,102	179,060	-3.3%
Tier 1 Planned Capacity	0	0	0%
Net Firm Capacity Transfers	-726	-872	20.1%
Anticipated Resources	184,376	178,188	-3.4%
Existing-Other Capacity	0	0	-
Prospective Resources	184,376	178,188	-3.4%
Reserve Margins	Percent (%)	Percent (%)	Annual Difference
Anticipated Reserve Margin	45.9%	39.8%	-6.1
Prospective Reserve Margin	45.9%	39.8%	-6.1
Reference Margin Level	14.9%	27.0%	12.1

SERC-East			
Demand, Resource, and Reserve Margins	2022–2023 WRA	2023–2024 WRA	2022–2023 vs. 2023–2024
Demand Projections	MW	MW	Net Change (%)
Total Internal Demand (50/50)	44,648	45,044	0.9%
Demand Response: Available	1,180	912	-22.7%
Net Internal Demand	43,468	44,132	1.5%
Resource Projections	MW	MW	Net Change (%)
Existing-Certain Capacity	53,287	54,229	1.8%
Tier 1 Planned Capacity	75	55	-26.6%
Net Firm Capacity Transfers	513	624	21.6%
Anticipated Resources	53,875	54,908	1.9%
Existing-Other Capacity	3	3	0.0%
Prospective Resources	53,877	54,910	1.9%
Reserve Margins	Percent (%)	Percent (%)	Annual Difference
Anticipated Reserve Margin	23.9%	24.4%	0.5
Prospective Reserve Margin	23.9%	24.4%	0.5
Reference Margin Level	15.0%	15.0%	0.0

SERC-Central			
Demand, Resource, and Reserve Margins	2022–2023 WRA	2023–2024 WRA	2022–2023 vs. 2023–2024
Demand Projections	MW	MW	Net Change (%)
Total Internal Demand (50/50)	41,745	42,282	1.3%
Demand Response: Available	1,671	1,753	4.9%
Net Internal Demand	40,074	40,529	1.1%
Resource Projections	MW	MW	Net Change (%)
Existing-Certain Capacity	51,008	50,196	-1.6%
Tier 1 Planned Capacity	0	1,386	-
Net Firm Capacity Transfers	-868	1,145	-231.9%
Anticipated Resources	50,140	52,727	5.2%
Existing-Other Capacity	3,601	1,255	-65.1%
Prospective Resources	53,741	54,002	0.5%
Reserve Margins	Percent (%)	Percent (%)	Annual Difference
Anticipated Reserve Margin	25.1%	30.1%	5.0
Prospective Reserve Margin	34.1%	33.2%	-0.9
Reference Margin Level	15.0%	15.0%	0.0

SERC-Florida Peninsula			
Demand, Resource, and Reserve Margins	2022–2023 WRA	2023–2024 WRA	2022–2023 vs. 2023–2024
Demand Projections	MW	MW	Net Change (%)
Total Internal Demand (50/50)	48,582	48,470	-0.2%
Demand Response: Available	2,870	2,753	-4.1%
Net Internal Demand	45,712	45,717	0.0%
Resource Projections	MW	MW	Net Change (%)
Existing-Certain Capacity	61,987	62,679	0.8%
Tier 1 Planned Capacity	237	344	522.2%
Net Firm Capacity Transfers	250	509	103.6%
Anticipated Resources	62,474	63,531	3.2%
Existing-Other Capacity	3,618	1,563	-56.8%
Prospective Resources	66,092	65,094	-0.1%
Reserve Margins	Percent (%)	Percent (%)	Annual Difference
Anticipated Reserve Margin	36.7%	39.0%	4.3
Prospective Reserve Margin	44.6%	42.4%	-0.2
Reference Margin Level	15.0%	15.0%	0.0

SERC-Southeast			
Demand, Resource, and Reserve Margins	2022–2023 WRA	2023–2024 WRA	2022–2023 vs. 2023–2024
Demand Projections	MW	MW	Net Change (%)
Total Internal Demand (50/50)	46,513	45,101	-3.0%
Demand Response: Available	1,954	2,018	3.3%
Net Internal Demand	44,559	43,083	-3.3%
Resource Projections	MW	MW	Net Change (%)
Existing-Certain Capacity	60,097	60,640	-0.8%
Tier 1 Planned Capacity	1,102	1,165	105.6%
Net Firm Capacity Transfers	-2,524	-815	-67.7%
Anticipated Resources	58,674	60,990	3.9%
Existing-Other Capacity	2,895	3,090	6.8%
Prospective Resources	61,569	64,081	4.1%
Reserve Margins	Percent (%)	Percent (%)	Annual Difference
Anticipated Reserve Margin	31.7%	41.6%	9.9
Prospective Reserve Margin	38.2%	48.7%	10.5
Reference Margin Level	15.0%	15.0%	0.0

Texas RE-ERCOT			
Demand, Resource, and Reserve Margins	2022–2023 WRA	2023–2024 WRA	2022–2023 vs. 2023–2024
Demand Projections	MW	MW	Net Change (%)
Total Internal Demand (50/50)	66,436	70,451	6.0%
Demand Response: Available	3,302	4,868	47.4%
Net Internal Demand	63,134	65,583	3.9%
Resource Projections	MW	MW	Net Change (%)
Existing-Certain Capacity	85,478	92,387	8.1%
Tier 1 Planned Capacity	644	228	-64.6%
Net Firm Capacity Transfers	20	20	0.0%
Anticipated Resources	86,142	92,635	7.5%
Existing-Other Capacity	0	0	-
Prospective Resources	86,710	93,203	7.5%
Reserve Margins	Percent (%)	Percent (%)	Annual Difference
Anticipated Reserve Margin	36.4%	41.2%	4.8
Prospective Reserve Margin	37.3%	42.1%	4.8
Reference Margin Level	13.75%	13.75%	0.0

SPP			
Demand, Resource, and Reserve Margins	2022–2023 WRA	2023–2024 WRA	2022–2023 vs. 2023–2024
Demand Projections	MW	MW	Net Change (%)
Total Internal Demand (50/50)	41,650	43,996	5.6%
Demand Response: Available	13	278	2006.1%
Net Internal Demand	41,637	43,718	5.0%
Resource Projections	MW	MW	Net Change (%)
Existing-Certain Capacity	71,131	61,173	-14.0%
Tier 1 Planned Capacity	0	0	-
Net Firm Capacity Transfers	-359	-498	-38.4%
Anticipated Resources	70,772	60,676	-14.3%
Existing-Other Capacity	0	0	-
Prospective Resources	70,496	60,630	-14.0%
Reserve Margins	Percent (%)	Percent (%)	Annual Difference
Anticipated Reserve Margin	70.0%	38.8%	-31.2
Prospective Reserve Margin	69.3%	38.7%	-30.6
Reference Margin Level	16.0%	19.0%	3.0

WECC-AB			
Demand, Resource, and Reserve Margins	2022–2023 WRA	2023–2024 WRA	2022–2023 vs. 2023–2024
Demand Projections	MW	MW	Net Change (%)
Total Internal Demand (50/50)	11,901	11,961	0.5%
Demand Response: Available	0	0	-
Net Internal Demand	11,901	11,961	0.5%
Resource Projections	MW	MW	Net Change (%)
Existing-Certain Capacity	13,144	13,694	4.2%
Tier 1 Planned Capacity	1,234	1511	22.5%
Net Firm Capacity Transfers	0	0	-
Anticipated Resources	14,378	15,205	5.8%
Existing-Other Capacity	0	0	-
Prospective Resources	14,378	15,205	5.8%
Reserve Margins	Percent (%)	Percent (%)	Annual Difference
Anticipated Reserve Margin	20.8%	27.1%	6.3
Prospective Reserve Margin	20.8%	27.1%	6.3
Reference Margin Level	11.1%	13.7%	2.6

WECC-BC			
Demand, Resource, and Reserve Margins	2022–2023 WRA	2023–2024 WRA	2022–2023 vs. 2023–2024
Demand Projections	MW	MW	Net Change (%)
Total Internal Demand (50/50)	11,395	11,651	2.2%
Demand Response: Available	0	0	-
Net Internal Demand	11,395	11,651	2.2%
Resource Projections	MW	MW	Net Change (%)
Existing-Certain Capacity	13,223	13,166	-0.4%
Tier 1 Planned Capacity	20	134	574.4%
Net Firm Capacity Transfers	0	110	-
Anticipated Resources	13,243	13,410	1.3%
Existing-Other Capacity	0	0	-
Prospective Resources	13,243	13,410	1.3%
Reserve Margins	Percent (%)	Percent (%)	Annual Difference
Anticipated Reserve Margin	16.2%	15.1%	-1.1
Prospective Reserve Margin	16.2%	15.1%	-1.1
Reference Margin Level	11.1%	13.7%	2.6

WECC-CA / MX			
Demand, Resource, and Reserve Margins	2022–2023 WRA	2023–2024 WRA	2022–2023 vs. 2023–2024
Demand Projections	MW	MW	Net Change (%)
Total Internal Demand (50/50)	38,978	38,328	-1.7%
Demand Response: Available	749	755	0.9%
Net Internal Demand	38,230	37,573	-1.7%
Resource Projections	MW	MW	Net Change (%)
Existing-Certain Capacity	55,287	56,405	2.0%
Tier 1 Planned Capacity	1,943	5400	177.9%
Net Firm Capacity Transfers	0	315	-
Anticipated Resources	57,231	62,120	8.5%
Existing-Other Capacity	0	0	-
Prospective Resources	57,326	62,136	8.4%
Reserve Margins	Percent (%)	Percent (%)	Annual Difference
Anticipated Reserve Margin	49.7%	65.3%	15.6
Prospective Reserve Margin	50.0%	65.4%	15.4
Reference Margin Level	8.4%	11.0%	2.6

WECC-NW			
Demand, Resource, and Reserve Margins	2022–2023 WRA	2023–2024 WRA	2022–2023 vs. 2023–2024
Demand Projections	MW	MW	Net Change (%)
Total Internal Demand (50/50)	58,605	57,408	-2.0%
Demand Response: Available	707	578	-18.3%
Net Internal Demand	57,898	56,829	-1.8%
Resource Projections	MW	MW	Net Change (%)
Existing-Certain Capacity	76,477	77,389	1.2%
Tier 1 Planned Capacity	988	2188	121.4%
Net Firm Capacity Transfers	0	1,964	-
Anticipated Resources	77,465	81,541	5.3%
Existing-Other Capacity	0	0	-
Prospective Resources	77,730	81,558	4.9%
Reserve Margins	Percent (%)	Percent (%)	Annual Difference
Anticipated Reserve Margin	33.8%	43.5%	9.7
Prospective Reserve Margin	34.3%	43.5%	9.2
Reference Margin Level	13.1%	17.4%	4.3

WECC-SW			
Demand, Resource, and Reserve Margins	2022–2023 WRA	2023–2024 WRA	2022–2023 vs. 2023–2024
Demand Projections	MW	MW	Net Change (%)
Total Internal Demand (50/50)	16,004	15,743	-1.6%
Demand Response: Available	318	285	-10.6%
Net Internal Demand	15,686	15,458	-1.5%
Resource Projections	MW	MW	Net Change (%)
Existing-Certain Capacity	29,799	28,306	-5.0%
Tier 1 Planned Capacity	553	1129	104.1%
Net Firm Capacity Transfers	0	0	-
Anticipated Resources	30,352	29,435	-3.0%
Existing-Other Capacity	0	0	-
Prospective Resources	30,352	29,587	-2.5%
Reserve Margins	Percent (%)	Percent (%)	Annual Difference
Anticipated Reserve Margin	93.5%	90.4%	-3.1
Prospective Reserve Margin	93.5%	91.4%	-2.1
Reference Margin Level	12.2%	16.4%	4.2

Variable Energy Resource Contributions

Because the electrical output of variable energy resources (e.g., wind, solar PV) depends on weather conditions, on-peak capacity contributions are less than nameplate capacity. In many areas, winter demand peaks in the early morning hours or other times of darkness, resulting in little or no electrical resource output from solar PV resources. The following table shows the capacity contribution of existing wind and solar PV resources at the peak demand hour for each assessment area. Resource contributions are also aggregated by Interconnection and across the entire BPS.

BPS Variable Energy Resources by Assessment Area									
Assessment Area / Interconnection	Wind			Solar			Hydro		
	Nameplate Wind (MW)	Expected Wind (MW)	Expected Share of Nameplate (%)	Nameplate Solar PV (MW)	Expected Solar (MW)	Expected Share of Nameplate (%)	Nameplate Hydro (MW)	Expected Hydro (MW)	Expected Share of Nameplate (%)
MISO	26,082	9,683	37%	2,559	130	5%	4,884	4,688	96%
MRO-Manitoba Hydro	259	52	20%	0	0	0%	6,220	5,548	89%
MRO-SaskPower	615	124	20%	0	0	0%	851	797	94%
NPCC-Maritimes	1,207	261	22%	42	0	0%	1,312	1,180	90%
NPCC-New England	1,463	397	27%	107	1	1%	3,565	2,472	69%
NPCC-New York	2,720	870	32%	154	13	9%	6,731	5,067	75%
NPCC-Ontario	4,943	1,433	29%	0	0	0%	8,985	5,185	58%
NPCC-Québec	3,820	1,375	36%	-	10	-	40,307	32,974	82%
PJM	11,992	3,695	31%	0	0	0%	3,027	3,027	100%
SERC-Central	28	8	28%	774	230	30%	4,967	3,315	67%
SERC-East	0	0	0%	6,245	1,483	24%	3,064	3,013	98%
SERC-Florida Peninsula	0	0	0%	3,499	1,264	36%	-	-	0%
SERC-Southeast	0	0	0%	5,234	1,889	36%	3,288	3,288	100%
SPP	33,120	6,856	21%	351	118	34%	5,465	4,996	91%
Texas RE-ERCOT	37,974	11,910	31%	16,403	2,547	16%	563	477	85%
WECC-AB	4,931	2,221	45%	0	0	0%	894	416	47%
WECC-BC	747	111	15%	0	0	0%	16,519	10,124	61%
WECC-CA/MX	9,443	848	9%	0	0	0%	13,957	4,606	33%
WECC-SW	3,121	994	32%	2,494	103	4%	1,202	844	70%
WECC-NW	20,697	6,319	31%	0	0	0%	41,860	22,752	54%
EASTERN INTERCONNECTION	120,404	35,318	29%	26,673	7,676	29%	52,316	42,578	81%
QUÉBEC INTERCONNECTION	3,820	1,375	36%	-	10	-	40,307	32,974	82%
TEXAS INTERCONNECTION	37,974	11,910	31%	16,403	2,547	16%	563	477	85%
WECC INTERCONNECTION	38,940	10,494	27%	2,494	103	4%	74,432	38,742	52%
INTERCONNECTION TOTAL:	201,137	59,098	29%	45,579	10,337	23%	167,618	114,771	68%

Probabilistic Assessment

Regional Entities and assessment areas provided a resource adequacy risk assessment that was probability-based for the winter season. Results are summarized in the table below.¹¹ The risk assessments account for the hour(s) of greatest risk of resource shortfall. For most areas, the hour(s) of risk coincides with the time of forecasted peak demand; however, some areas incur the greatest risk at other times based on the varying demand and resource profiles. Various risk metrics are provided and include loss of load expectation (LOLE), loss of load hours (LOLH), EUE, and the probabilities of EEA occurrence.

Probability-Based Risk Assessment		
Area	Type of Assessment	Results and Insight from Assessment
MRO-Manitoba	Verification of NERC 2022 Probabilistic Assessment (2022 ProbA)	The annual probabilistic statistics for model year 2024 for the 2022 Probabilistic Assessment (ProbA) show: • Base Case: 29 MWh per year of EUE • Risk Scenario (10th percentile water flow conditions): 477 MWh per year of EUE An expected unserved energy in the 29 to 477 MWh range is a reasonable estimate for the winter 2023–2024 based on the 2022 NERC ProbA Base Case for the year 2024 given comparable loads and resources, and that water flow conditions are, as of late summer 2023, below average but still above the 10th percentile.
MRO-SaskPower	Probability-based capacity adequacy assessment	Results indicate that the expected number of hours with operating reserve deficiency for the 2023–2024 winter season is 0.31 hours. The estimated probability of having generation forced outages of 350 MW or greater in the winter season is 11.2%. A Risk of supply shortfall exists when generation forced outages at this level coincide with periods of high demand.
NPCC	NPCC conducted an all-hour probabilistic reliability assessment that consisted of a base case and severe case examining low resources, reduced imports, and higher loads. The highest peak load scenario has a 7% probability of occurring. Preliminary results are included in this table. NPCC will publish final probabilistic assessment results in December. ¹²	The assessment forecasts that the NPCC Regional Entity will have an adequate supply of electricity this winter and a low risk of disconnecting load. Necessary strategies and procedures are in place to deal with operational challenges and emergencies as they may develop. Results of the probabilistic analysis by assessment area are below. The assessment evaluates the probabilistic indices of LOLE, LOLH and EUE.
NPCC-Maritimes		NPCC’s assessment preliminary results indicate that operating procedures are sufficient to maintain a balance between electricity supply and demand, if needed. Only the low likelihood reduced resource case, highest peak load scenario resulted in an estimated cumulative LOLE risk of ~0.1 days/period, with associated LOLH (<1 hour/period) and EUE (10.6 MWh) over the November–March winter period. The Maritimes area low likelihood resource case assumed that wind capacity would be de-rated by half (1,200 to 600 MW) for every hour in December through February to simulate icing conditions and a 50% natural gas capacity curtailment (610 to 305 MW) to simulate a reduction in gas supply for December through February (dual fuel units assumed reverting to oil) and reduced transfer capabilities.

¹¹ A probabilistic assessment for the 2023-2024 winter is not available for SPP at the time of publication. SPP’s 2023 Loss of Load Expectation (LOLE) Study incorporates modeling assumptions based on recent winter events. SPP expects to complete the study prior to the end of 2023. For more information see the study scope document here: [2023 LOLE Scope](#)

¹² Based on October 2023 revised results. The final [NPCC 2023–2024 Winter Reliability Assessment](#) be available in December 2023.

Probability-Based Risk Assessment		
Area	Type of Assessment	Results and Insight from Assessment
NPCC-New England		NPCC’s assessment preliminary results indicate that operating procedures were not needed to maintain a balance between electricity supply and demand. No cumulative LOLE, LOLH or EUE risks were indicated over the November–March winter period, for all the scenarios modeled. The New England Area low likelihood resource case assumed 500 MW of additional maintenance outages, ~4,817 MW of gas-fired generation unavailable due to fuel supply constraints, and 50% reduced import capabilities of external ties (i.e., 1,850 MW total). The NPCC Probabilistic Assessment did not evaluate a prolonged, extreme cold weather event that threatens to exhaust stored liquid fuels.
NPCC-New York		NPCC’s assessment preliminary results indicate that operating procedures were not needed to maintain a balance between electricity supply and demand. No cumulative LOLE, LOLH or EUE risks were indicated over the November–March winter period for all the scenarios modeled.
NPCC-Ontario		NPCC’s assessment preliminary results indicate that operating procedures were not needed to maintain a balance between electricity supply and demand. No cumulative LOLE, LOLH or EUE risks were indicated over the November–March winter period for all the scenarios modeled.
NPCC-Québec		NPCC’s assessment preliminary results indicate that operating procedures are sufficient to maintain a balance between electricity supply and demand, if needed. Only the low likelihood reduced resource case, highest peak load scenario resulted in an estimated cumulative LOLE risk of ~0.1 days/period, with associated LOLH (<1 hour/period) and EUE (92.7 MWh) over the November–March winter period. The Québec Area low likelihood resource case assumed: 1,000 MW of generation reductions.
PJM	Based on 2022 PJM Reserve Requirement Study (RRS)	PJM is expecting a low risk of resources falling below required operating reserves. PJM forecasts a 40% installed reserve margin, well above the target of 27%. The RRS analyzed a wide range of load scenarios (low, regular and extreme) as well as multiple scenarios for system-wide unavailable capacity due to forced outages, maintenance outages and ambient derations. The RRS report was also influenced by the extreme weather experienced in December of 2022. NERC assesses an elevated risk of energy shortfall for the upcoming winter due to the potential for a weather event on the scale of Winter Storm Elliott to cause similar generation outages from fuel and winterization issues.
SERC	Verification of NERC 2022 ProbA Results	The 2022 Base Case results indicated adequate resources for the SERC Regional Entity. The base case did not include high-outage conditions similar to those experienced during Winter Storm Elliott.
Texas RE-ERCOT	ERCOT Probabilistic Reserve Risk Model	There is a 11.6% probability that ERCOT will declare an EEA1 during the highest-risk hour ending at 8:00 am. The Probabilistic Reserve Risk Model, which performs Monte Carlo simulations, determines the probability that capacity available for operating reserves for a seasonal peak load day is at or below the various EEA risk thresholds.
WECC	The 2022 Western Assessment of Resource Adequacy provides the most recent probability-based resource adequacy risk assessment for Summer 2023 across WECC’s areas.	The Western Interconnection is experiencing heightened reliability risks heading into Summer 2023 due to increased supply-side shortages and fuel constraints along with ongoing drought impacts in some areas, continued wildfire threats, and expanding heat wave events. The installation of new resources for the summer and the availability of the imports, especially during wide-area heat events, affects resource adequacy for the U.S. assessment areas. The reliability and resource adequacy of the Western Interconnection depends on the ability to move power throughout the footprint.
WECC-AB		Alberta is expected to have sufficient resource availability to meet demand and cover reserves under a winter peak defined at the 90th percentile. When wind output is below average, imports are likely to be needed to meet operating reserves for normal and above-normal peak demand.

Probability-Based Risk Assessment		
Area	Type of Assessment	Results and Insight from Assessment
WECC-BC		BC is expected to have sufficient resource availability to meet demand and cover reserves under a winter peak defined at the 90th percentile. When hydroelectric generation output is below average, imports are likely to be needed to meet operating reserves for normal and above-normal peak demand.
WECC-CA/MX		WECC-CA/MX is expected to have sufficient resource availability to meet demand and cover reserves under a winter peak defined at the 90th percentile.
WECC-NW		WECC-NW is expected to have sufficient resource availability to meet demand and cover reserves under a winter peak defined at the 90th percentile. In a scenario involving high thermal generation outages, low wind output, and low hydroelectric generation output, imports are likely to be needed to meet operating reserves for normal and above-normal peak demand.
WECC-SW		WECC-SW is expected to have sufficient resource availability to meet demand and cover reserves under a winter peak defined at the 90th percentile.

Errata

December 2023

- Updated On-Peak Reserve Margin graphics for NPCC-New York (page 18) and SERC-Florida Peninsula (page 25)
- Updated fuel mix chart for WECC-Alberta (Page 28)
- Updated Figure 5 to reflect NPCC-New York 2022-2023 Reference Margin Level and SERC-Florida Peninsula reserve margins (page 36)
- Updated capacity numbers provided by SERC-East, SERC-Florida Peninsula, and SERC-Southeast (pages 40–41)
- Revised percentage change numbers for SPP (page 41)
- Added footnote to reference SPP’s probabilistic study (page 44)

BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c))
Emergency Order: Transalta)
Centralia Generation LLC)
_____)

Order No. 202-25-11

Motion to Intervene, Motion for Clarification, and Requests for Rehearing and Stay
of Sierra Club, NW Energy Coalition, Washington Conservation Action, Climate
Solutions, Public Citizen, and Environmental Defense Fund
(collectively, “Public Interest Organizations” or “PIOs”)

Exhibit 1-92:
WECC 2024 Western Assessment of Resource Adequacy Demand at Risk Analysis

Demand at Risk by Subregion

WECC's annual [Western Assessment of Resource Adequacy](#) (Western Assessment) examines resource-adequacy-related risks concerning the reliability of the Western Interconnection over the next 10 years. Through an energy-based probabilistic approach, WECC looks at the risks throughout the interconnection and five subregions (See Figure 1). This work is meant to help stakeholders target specific areas and topics for deeper evaluation and mitigation.

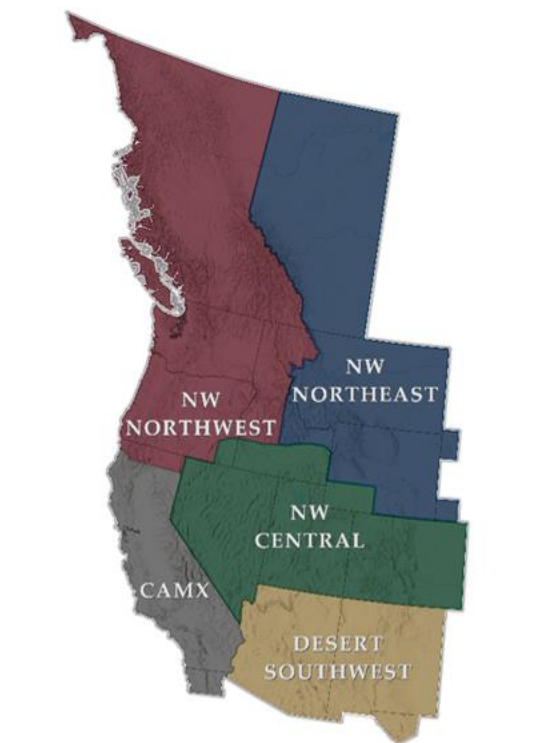


Figure 1: Map of the Western Interconnection with subregions

In the 2024 Western Assessment, WECC studied four resource addition scenarios. In the first scenario (All Additions), all planned resource additions come online in the year scheduled over the next 10 years. The remaining scenarios examine the effects on reliability if only 95%, 85%, and 55% of planned resource additions come online on schedule. This document provides noteworthy demand-at-risk takeaways within the subregions studied.

All Additions

There was demand at risk in one subregion, NW-Northwest, in the scenario in which all planned resource additions were made. A total of 89 demand-at-risk hours appeared in this scenario, with all but four of those hours occurring in the winter (See Figure 2). Most of the risk occurred in 2029 and later years, peaking at 26 hours in 2034.

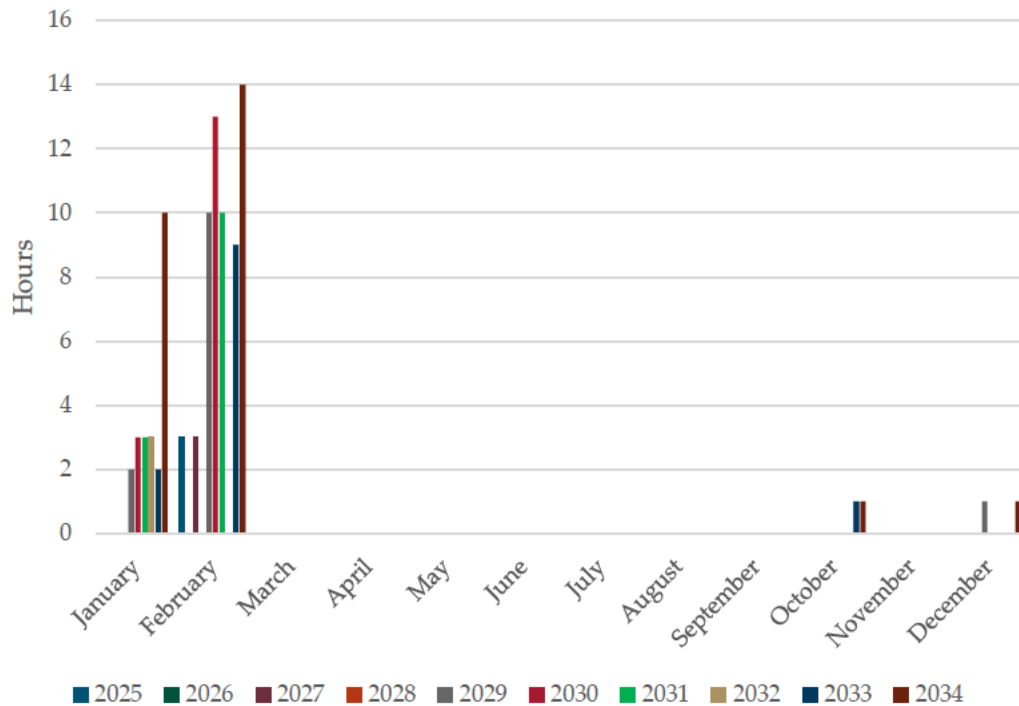


Figure 2: Demand-at-risk hours in the NW-Northwest subregion in the All-Additions scenario

95% Scenario

Demand at risk appeared in two subregions in this scenario: NW-Northwest and NW-Northeast. As in the 100% scenario, most of the demand at risk occurred in the winter months in the NW-Northwest (See Figure 3). In the NW-Northeast, all but four of the demand-at-risk hours occurred in August, beginning with one hour in 2027 and increasing to 51 hours in 2034 (See Figure 4).

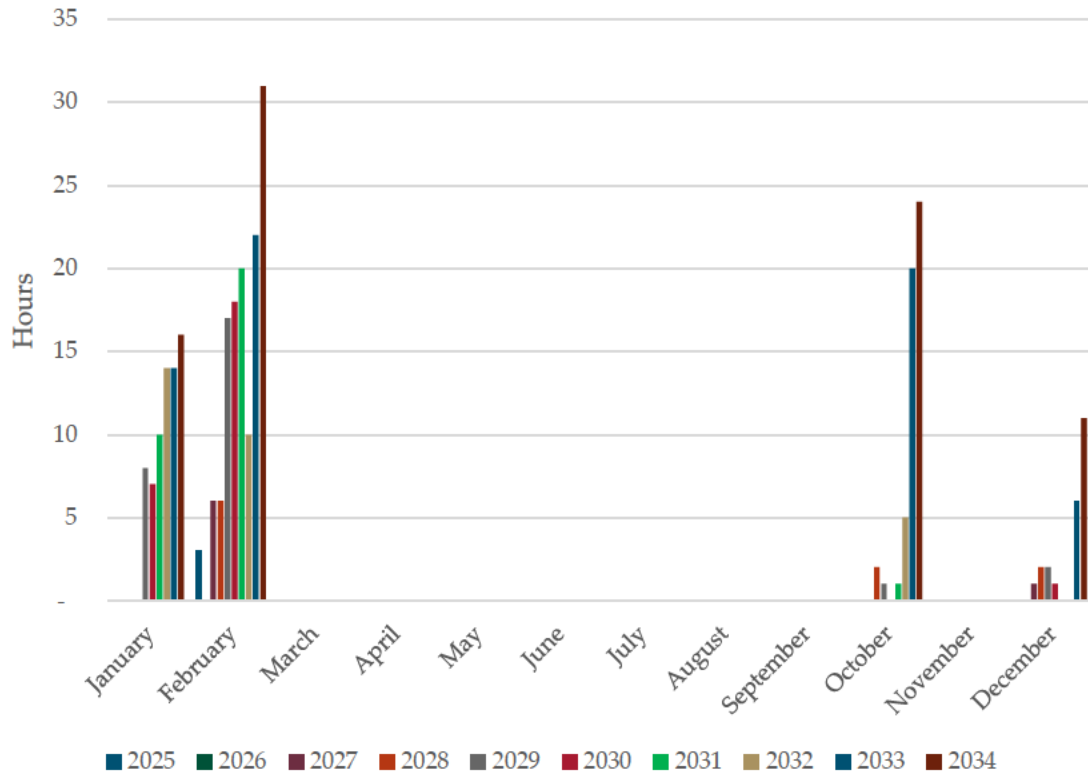


Figure 3: Demand-at-risk hours in the NW-Northwest subregion in the 95% scenario

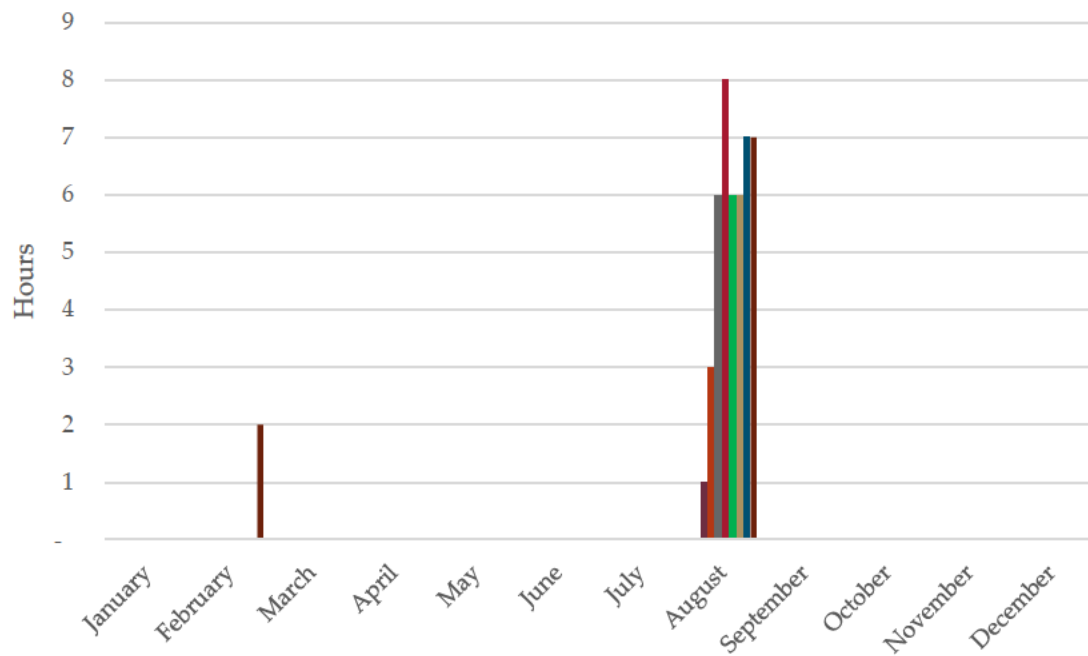


Figure 4: Demand-at-risk hours in the NW-Northeast subregion in the 95% scenario

85% Scenario

Demand at risk occurred in three subregions in this scenario: NW-Northwest, NW-Northeast, and NW-Central. Only one hour of demand at risk appeared in the NW-Northeast subregion (See Figure 6), in August 2034, while 94 hours appeared in the NW-Central (See Figure 7), all between June and September and with almost half of that in 2034. In the NW-Northwest, 311 demand-at-risk hours appeared in this scenario, most of that in the winter (See Figure 5).

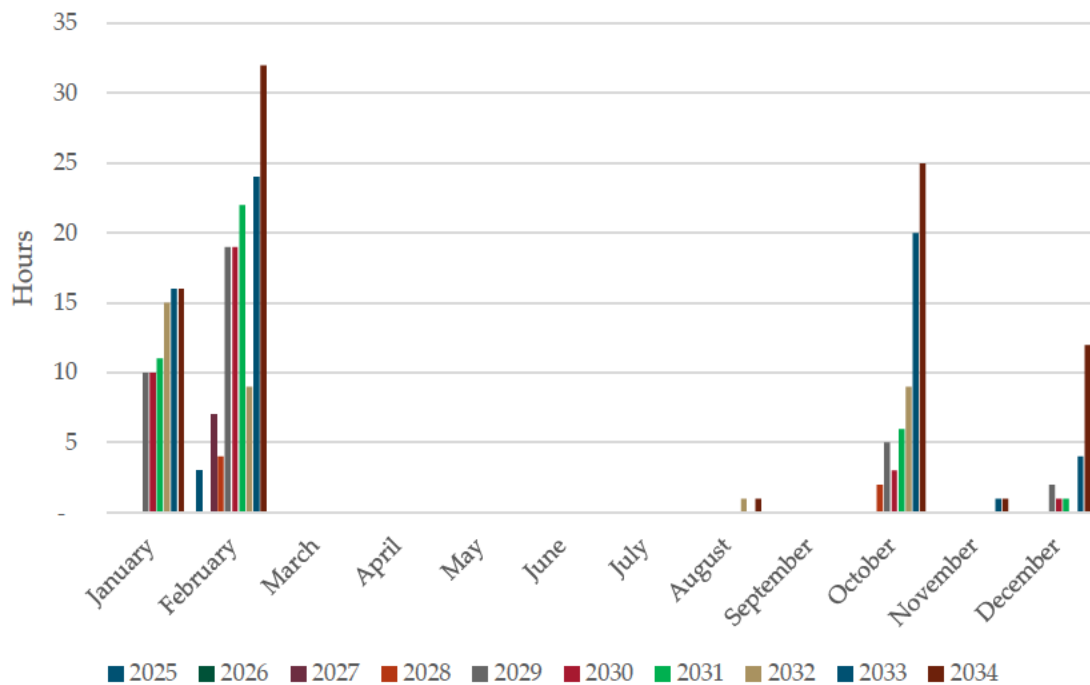


Figure 5: Demand-at-risk hours in the NW-Northwest subregion in the 85% scenario

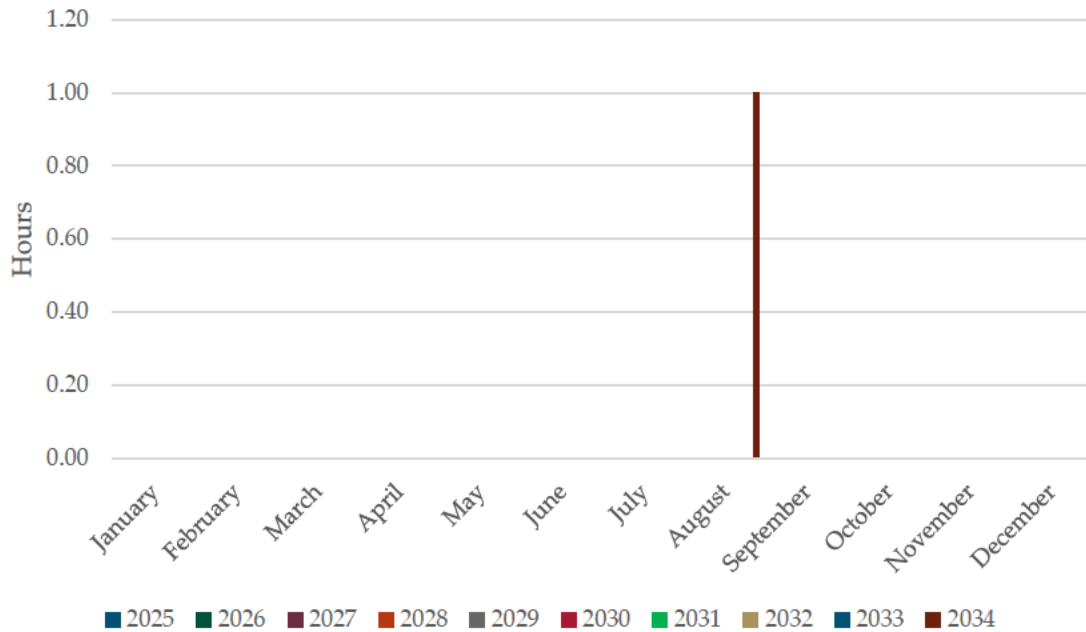


Figure 6: Demand-at-risk hours in the NW-Northeast subregion in the 85% scenario

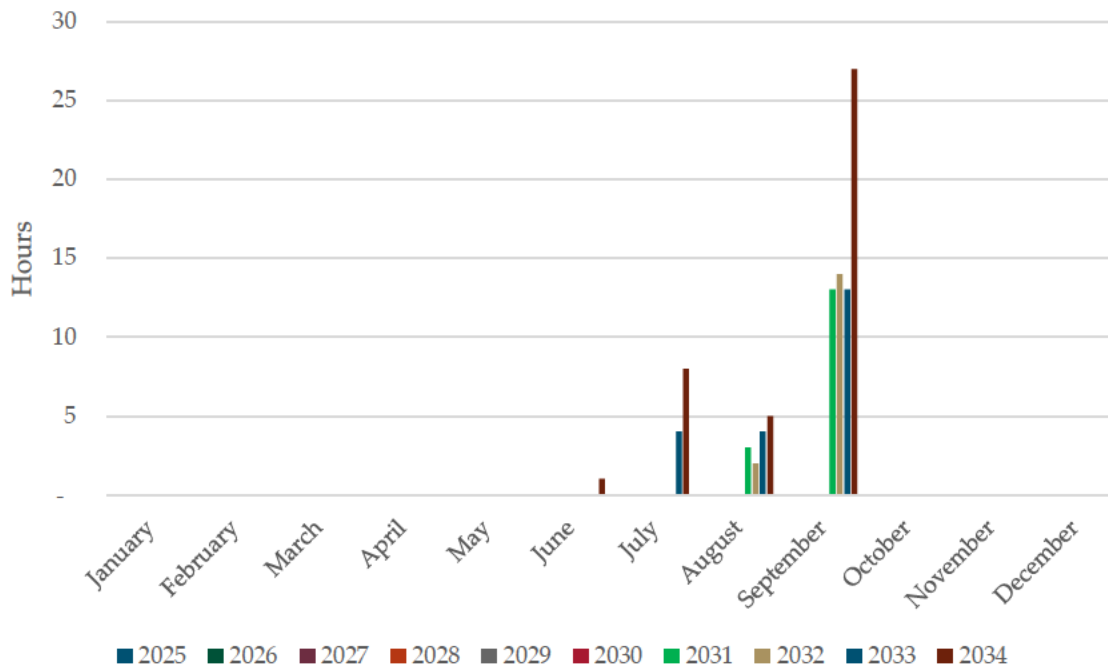


Figure 7: Demand-at-risk hours in the NW-Central subregion in the 85% scenario

55% Scenario

Demand at risk increased to four of the interconnection's five subregions in this scenario. Again, the most demand at risk occurred in the NW-Northwest in this scenario (See Figure 9), beginning in 2025 with eight hours and increasing to almost 800 hours in 2034. Most of the demand at risk in the other subregions occurred in the summer (See Figure 8, 10, and 11).

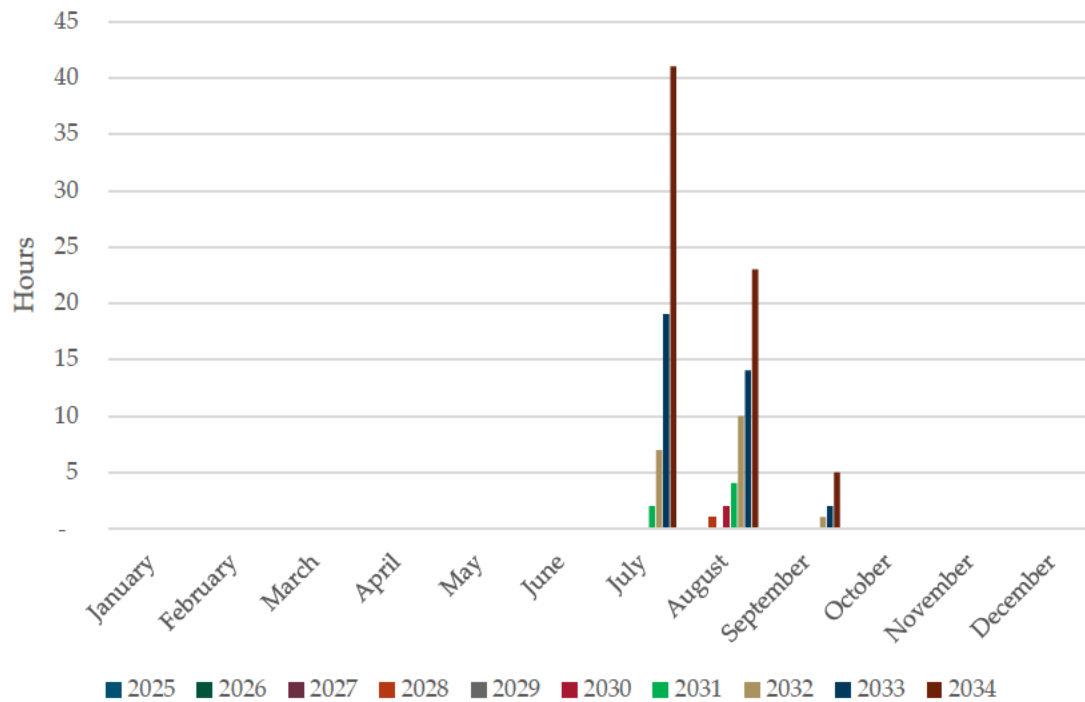


Figure 8: Demand-at-risk hours in the Desert Southwest subregion in the 55% scenario

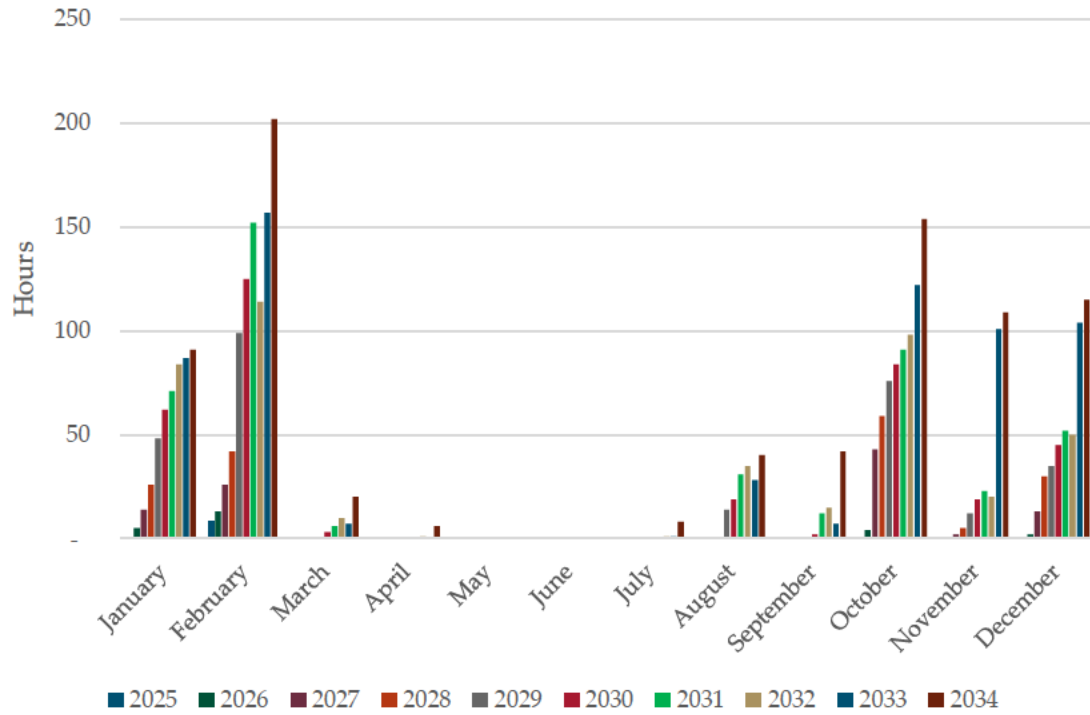


Figure 9: Demand-at-risk hours in the NW-Northwest subregion in the 55% scenario

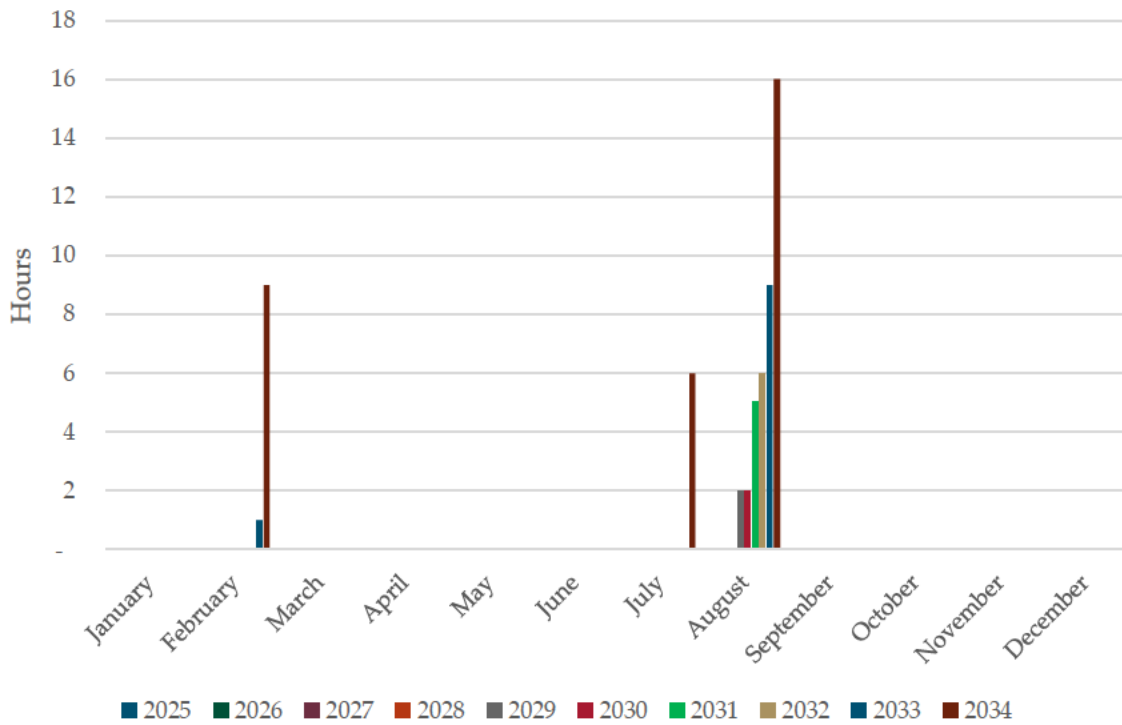


Figure 10: Demand-at-risk hours in the NW-Northeast subregion in the 55% scenario

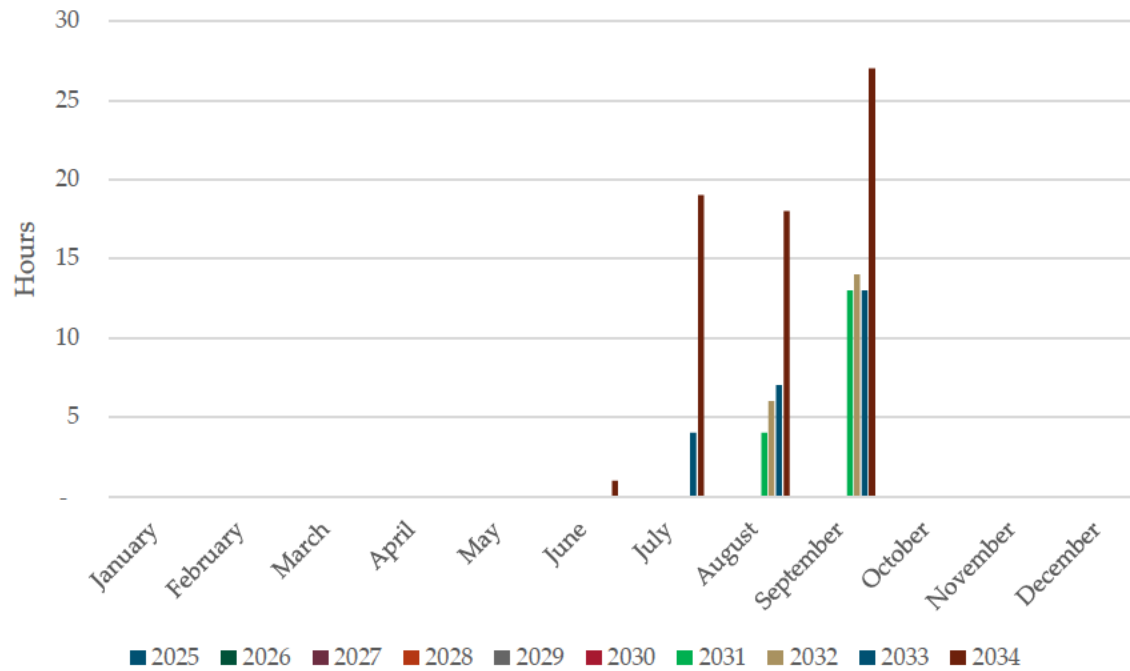


Figure 11: Demand-at-risk hours in the NW-Central subregion in the 55% scenario

BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c))
Emergency Order: Transalta)
Centralia Generation LLC)
_____)

Order No. 202-25-11

Motion to Intervene, Motion for Clarification, and Requests for Rehearing and Stay
of Sierra Club, NW Energy Coalition, Washington Conservation Action, Climate
Solutions, Public Citizen, and Environmental Defense Fund
(collectively, “Public Interest Organizations” or “PIOs”)

Exhibit 1-93:
Bonneville Day-Ahead Market Policy

Bonneville Power Administration

Day-Ahead Market Policy

May 9, 2025

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1. Executive Summary

The Bonneville Power Administration's Day-Ahead Market Policy (Policy) contains the policy direction of the Administrator of the Bonneville Power Administration based on the extensive stakeholder process analyzing Bonneville's potential day-ahead market participation in the California Independent System Operator's (CAISO) Extended Day-Ahead Market (EDAM) or the Southwest Power Pool's (SPP) Markets+. Bonneville conducted its stakeholder process from July 2023 through May 2025. During this time, Bonneville was, and continues to be, an active participant in both CAISO and SPP's stakeholder processes. The purpose of the Day-Ahead Market Policy is to transparently inform stakeholders about the scope of subsequent actions towards market participation.

On March 6, 2025, Bonneville issued its Day-Ahead Market Draft Policy, which proposed Bonneville should participate in a day-ahead market and pursue participation in Markets+ due to its superior market design, independent governance structure, and inclusive stakeholder process. This was followed by a 30-day formal comment period, which resulted in 1,614 comments. This Policy provides background information, addresses issues raised during the comment period and memorializes Bonneville's final direction and provides initial guidance on next steps.

After careful consideration of public input on Bonneville's evaluation principles and key considerations, governance and stakeholder processes, resource adequacy and resource sufficiency, price formation and market power mitigation, transmission and congestion rent and greenhouse gas accounting, Bonneville will adopt the recommendations in the draft policy and pursue participation in a day-ahead market and specifically pursue participation in Markets+.

Bonneville will now shift its focus to joining Markets+ by initiating a formal process to implement Markets+ participation. Bonneville will address customers' and stakeholders' impacts in future proceedings such as its rate case and tariff terms and conditions proceedings, and if Bonneville ultimately joins the market as a participant, it will address impacts in these forums as well as transmission business practice updates and a Provider of Choice power sales contract day-ahead market amendment process. Bonneville will leverage the lessons learned from its Western Energy Imbalance Market (WEIM) decision process, ultimately making a decision to go-live after reevaluating it through the implementation process, including any changes to the structure of Markets+ or underlying facts since the earlier phase of Markets+ final policy.

2. Introduction

In July 2023, Bonneville began to engage the region in a public process to evaluate its potential participation in a day-ahead market. As one of the largest wholesale power and transmission providers in the Western Interconnection, Bonneville’s decision regarding day-ahead market participation will play a critical role in the energy and capacity market landscape for the region.

2.1. Description of the Bonneville System

Bonneville is a federal power marketing administration under the United States (U.S.) Department of Energy, is self-funding, and covers its costs by selling its products and services. Bonneville makes power sales and provides transmission service within its statutorily defined service territory in the Pacific Northwest,¹ including Idaho, Oregon, Washington, western Montana and small parts of eastern Montana, California, Nevada, Utah, and Wyoming. Bonneville markets about 32% of the wholesale electric power generated in the Pacific Northwest² from 31 federal hydroelectric dams, one non-federal nuclear plant, and several smaller non-federal generating resources.³ See Figure 1 for a visual of hydroelectric resources. Bonneville also operates and maintains more than 15,000 circuit miles of high-voltage transmission in its service territory, which is used to deliver power to its customers and transmit power for third-party transmission customers.

Figure 1 | Transmission System and Federal Dams



Bonneville’s statutory mission is threefold: (1) to provide an adequate, efficient, economical, and reliable power supply to its firm power customers in the Pacific Northwest; (2) to provide a transmission system that is adequate to the task of integrating and transmitting power from federal and non-federal resources, providing service to Bonneville’s customers, providing interregional interconnections, and maintaining electrical reliability and stability; and (3) to mitigate the impacts on fish and wildlife from the federally owned hydroelectric projects from which Bonneville markets power.

¹ In this Policy, the “Pacific Northwest” or “region” has the meaning set forth in the Northwest Power Act, 16 U.S.C. § 839a(14).

² Bonneville Power Administration, BPA Facts (Sept. 2024), available at <https://www.bpa.gov/about/newsroom/factsheets>.

³ *Id.*; see also Bonneville Power Administration, 2024 Pacific Northwest Loads and Resources Study (Aug. 2024) (“The White Book”), available at <https://www.bpa.gov/-/media/Aep/power/white-book/2024-white-book.pdf>.

2.2. Development of Day-Ahead Markets in the West

As background, the Bulk Electric System in the U.S. is managed in six different regions.⁴ The Western Interconnection is the largest region encompassing 38 Balancing Authority Areas (BAAs)⁵ that are individually responsible for ensuring the reliable operation of the electric grid.⁶ The regulatory Regional Entity approved by the Federal Energy Regulatory Commission (FERC) for the Western Interconnection is the Western Electricity Coordinating Council (WECC). The North American Electric Reliability Corporation (NERC) delegated some of its authority to create, monitor, and enforce reliability standards to WECC through a Delegation Agreement.⁷ WECC promotes bulk power system reliability and security.

Historically, entities within the Western Interconnection have managed and balanced electricity supply and demand through bilateral transactions across forward contracts of varying duration, day-ahead transactions, and real-time transactions. The CAISO BAA is an exception in its role as an Independent System Operator (ISO).⁸ Outside of the Western Interconnection, most regions have transitioned from a bilateral framework into ISOs or Regional Transmission Organizations (RTOs).⁹ RTOs and ISOs manage about 60% of the U.S. electric power supply¹⁰ and expand market activities through the consolidation of many BAAs into one BAA. They each maintain a single Open Access Transmission Tariff with standardized terms and conditions for transmission service and centralized transmission planning.

One component of RTOs and ISOs is the inclusion of a centrally organized market. A centrally organized market is administered by a market operator, which is a clearinghouse for bids and offers from market participants. Market participants continue to transact bilaterally on a forward time horizon but allow the market to dispatch generation and serve load across the day-ahead and real-time time horizons.¹¹ All centralized markets use Security Constrained Unit Commitment (SCUC) and Security Constrained Economic Dispatch (SCED) accompanied by a nodal network model with Locational Marginal Pricing

⁴ For more information, see Federal Energy Regulatory Commission (FERC), Electric Power Markets, *available at* <https://www.ferc.gov/electric-power-markets>.

⁵ A BAA is defined as “The collection of generation, transmission, and loads within the metered boundaries of the Balancing Authority. The Balancing Authority maintains load-resource balance within this area.” North American Electric Reliability Corp., Glossary of Terms used in NERC Reliability Standards at 5 (Jan. 7, 2025), *available at* https://www.nerc.com/pa/stand/glossary%20of%20terms/glossary_of_terms.pdf. In turn, a Balancing Authority is defined as “The responsible entity that integrates resource plans ahead of time, maintains Demand and resource balance within a Balancing Authority Area, and supports Interconnection frequency in real time.” *Id.*

⁶ BAAs are responsible for meeting North American Electric Reliability Corporation (NERC) reliability compliance standards (*see NERC*, *available at* <https://www.nerc.com>) and Western Electricity Coordinating Council (WECC) reliability compliance standards (*see WECC*, *available at* <https://www.wecc.org>).

⁷ WECC, About WECC, *available at* <https://www.wecc.org/about/about-wecc>.

⁸ FERC Order No. 888, 75 FERC ¶ 61,080, promoted the concept of ISO formation based on an earlier “power pool” concept. Several groups of transmission owners then formed ISOs, some from existing power pools. Along with facilitating open access to transmission, ISOs operate the transmission system independently, and foster competition for electricity generation among wholesale market participants.

⁹ In Order No. 2000, 89 FERC ¶ 61,285, FERC encouraged utilities to join regional transmission organizations (RTOs), which, like an ISO, would operate the transmission systems and develop innovative procedures to manage transmission equitably.

¹⁰ U.S. Energy Information Administration, *About 60% of U.S. Electric Power Supply is Managed by RTOs* (Apr. 4, 2011), *available at* <https://www.eia.gov/todayinenergy/detail.php?id=790#:~:text=Source:%20ISO/RTO%20Council,power%20markets%20and%20energy%20traders>.

¹¹ An RTO is an entity that is independent from all generation and power marketing interests and has exclusive responsibility for grid operations, short-term reliability, and transmission service within the region. Enerdynamics, Energy Knowledge Database, FERC Order 2000, *available at* <https://energyknowledgebase.com/topics/ferc-order-2000.asp>.

(LMP)¹² to create an “economic dispatch.”¹³ Section 1234 of the Energy Policy Act of 2005 defines “economic dispatch” as “the operation of generation facilities to produce energy at the lowest cost to reliably serve consumers, recognizing any operational limits of generation and transmission facilities.”¹⁴

CAISO operated an organized day-ahead and real-time market solely within its BAA footprint comprising most of California until 2014. In 2014, CAISO expanded its real-time market by offering the Western Energy Imbalance Market (WEIM) as an option for other BAAs in the Western Interconnection to join.¹⁵ Voluntarily on an hourly basis, participants offer resources for within-hour dispatch by the market to manage the difference in energy for load and resources between what was scheduled ahead of time and what materializes in real-time. The market operator uses SCED to meet the within-hour real-time energy imbalances with the most cost-effective generation offered to the market. Unit commitment is generally performed by the market participants, not by CAISO in this real-time market. WEIM balances fluctuations in supply and demand by dispatching lower cost resources and it manages congestion on transmission lines to maintain grid reliability and to support integrating new resources.¹⁶

WEIM now includes 21 BAA participants operating the majority of the Western Interconnection.¹⁷ CAISO’s overarching market governance is entrusted to the CAISO Board of Governors. The Board has delegated certain authority for the WEIM to the Western Energy Markets (WEM) Governing Body, subject to the Board’s oversight, in a model referred to as Joint Authority.¹⁸ The CAISO Board of Governors is appointed by the Governor of California with the consent of the California State Senate.

In 2021, SPP launched a second imbalance market offering in the Western Interconnection, the Western Energy Imbalance Service market (WEIS). The WEIS has 16 participants. SPP’s independent board of directors provides ultimate oversight of the administration of the WEIS market. In its role as the market operator, SPP performs analysis to ensure each balancing authority (BA) and market participant in each BA’s boundaries have enough generation in their operating plan to satisfy the load and obligations for that

¹² See SPP Markets+ Tariff, Attach. A § 3.2, available at https://www.spp.org/Documents/71376/Markets%20Plus%20Tariff%20amended%2020240405_filed%20version%202.pdf (“The LMP at a Pnode is the cost of delivering an incremental MW of Energy at that specific Pnode, while satisfying all operational constraints where such cost will include applicable Demand Curve prices if the incremental MW of Energy would result in a corresponding increase in shortage conditions. The LMP at any Pnode is the sum of three components: the marginal costs of Energy (the MEC), the marginal cost of losses (the MLC), and the marginal cost of congestion (the MCC)”). LMPs are the commonly accepted means for settling resources and loads in all centrally organized markets in the U.S. For more thorough details on the history and development of LMPs and the various considerations of how they are used within organized markets, see Harvey Scott & William Hogan, *Locational Marginal Prices and Electricity Markets* (2022), available at https://whogan.scholars.harvard.edu/sites/g/files/omnuum4216/files/whogan/files/locational_marginal_prices_and_electricity_markets_hogan_and_harvey_paper_101722.pdf.

¹³ See FERC, Security Constrained Economic Dispatch: Definitions, Practices, Issues, and Recommendations: A Report to Congress Regarding the Recommendations of Regional Joint Boards for the Study of Economic Dispatch Pursuant to Section 223 of the Federal Power Act as Added by Section 1298 of the Energy Policy Act of 2005 (July 31, 2006), available at <https://www.ferc.gov/sites/default/files/2020-05/final-cong-rpt.pdf>.

¹⁴ 42 U.S.C. § 16432.

¹⁵ See CAISO, Western Energy Imbalance Market (WEIM) (2025), available at <https://www.westerneim.com/Pages/About/default.aspx>.

¹⁶ See CAISO, How the Markets Work (2025), available at <https://www.westerneim.com/Pages/About/HowItWorks.aspx>.

¹⁷ See CAISO, Western Energy Imbalance Market (WEIM) (2025), available at <https://www.westerneim.com/Pages/About/default.aspx>.

¹⁸ See CAISO, Governance (2025), available at <https://www.westerneim.com/Pages/Governance/default.aspx>.

market participant and BA.¹⁹ The WEIS accommodates a diverse set of resource types. This helps ensure the market operates as efficiently as possible and can take advantage of the capabilities of different resources.²⁰ As of 2022, WEIS balanced the demand for real-time energy and the power produced by more than 150 generating units in its multi-state footprint.²¹

Both CAISO and SPP have developed proposals to develop day-ahead markets that would manage a significant increase in the volume of transactions. CAISO began development of EDAM in 2019,²² and SPP began development of Markets+ in 2022.^{23,24} A day-ahead market is designed to optimize a participant's loads, resources, and transmission within the market footprint using a security constrained unit commitment and economic dispatch on a day-ahead basis with hourly granularity coupled with the underlying real-time market. In the real-time WEIM and WEIS markets, participants can submit voluntary bids for the next hour in sub-hourly (15-minute or five-minute) increments. In contrast, in a day-ahead market, participants can bid generation capacity and load for every hour in the day-ahead timeframe, which is then optimized by the unit commitments and economic dispatch accounting for constraints, including transmission availability and congestion. A day-ahead market continues to include a real-time market component, including voluntary submissions of any remaining real-time energy, much like the existing WEIM and WEIS.

Notably, CAISO and SPP employed different stakeholder participation models to develop the EDAM and Markets+ proposals. CAISO designed and authored the EDAM market offering, and Bonneville participated in stakeholder meetings, reviewed proposals, and provided written comments. CAISO ultimately determined which stakeholder suggestions to address and incorporate into the final EDAM design. Certain key issues that Bonneville raised were not fully addressed. In contrast, while SPP developed the initial conceptual framework for Markets+, stakeholder workgroups developed the Markets+ design elements to reflect the operational characteristics of the Western Interconnection. Bonneville participated in the committees, work groups, and task forces that developed Markets+ tariff language and business protocols. The collaborative design framework of Markets+ better addressed the many issues raised by Bonneville and other stakeholders.

2.3. Why is Bonneville Considering Joining a Day-Ahead Market?

Bonneville joined CAISO's WEIM in May 2022, eight years after its inception, after the market had grown into a large footprint and matured in its design elements. With FERC approval of two day-ahead market offerings, Bonneville expects day-ahead markets to gain a foothold, particularly with some states requiring utilities to transition to organized markets.²⁵ Based on its experience as a later entrant to the WEIM, Bonneville believes that early day-ahead market involvement will better meet its customer and stakeholder

¹⁹ See SPP, A Proposal for the Southwest Power Pool Western Energy Imbalance Service (WEIS) (2019), *available at* <https://www.spp.org/documents/60104/a%20proposal%20for%20spp's%20western%20energy%20imbalance%20service%20market.pdf>.

²⁰ See SPP, Western Energy Imbalance Service Market (2025), *available at* <https://www.spp.org/western-services/weis/>.

²¹ SPP, Annual Report 2022 at 4, *available at* <https://spp.org/documents/70194/2022%20annual%20report%20-%20209.26.23.pdf>.

²² See CAISO, Initiative: Extended day-ahead market, *available at* <https://stakeholdercenter.caiso.com/StakeholderInitiatives/Extended-day-ahead-market>.

²³ See SPP, Markets+, *available at* <https://www.spp.org/western-services/marketsplus/>.

²⁴ SPP is also developing RTO West in the Western Interconnection, with the corresponding tariff approved by FERC on March 20th, 2025. See *Southwest Power Pool, Inc., 190 FERC ¶61,169 (2025)*. RTO West is a separate offering from Markets+ and is not co-optimized with the Markets+ footprint.

²⁵ FERC Office of Public Participation, Western Energy Markets Explainer (Jan. 2025), *available at* <https://www.ferc.gov/OPP/western-markets-explainer>.

objectives because the first years of a market greatly influence development and maturation of the market design. The following are some categories of benefits that are associated with day-ahead market participation.

Continued Access to Trading Partners via a Liquid Market

Bonneville has observed a strong interest in day-ahead market development across the West, and many entities have already indicated their intent to pursue participation in the coming years. Today, Bonneville transacts bilaterally to ensure it meets its load service and operational obligations and to maximize the value of net-secondary revenue to keep rates low for customers. As entities joined the WEIM, Bonneville and others outside of the WEIM noticed reductions in the liquidity of the hourly bilateral market. Similarly, Bonneville expects that organized day-ahead market growth may result in reduced liquidity in both the day-ahead and real-time bilateral markets.²⁶ The expected result is fewer options for bilateral purchases of power or fewer counterparties to sell to, which could result in operational impacts and increased financial hurdles associated with these transactions. Participation in a day-ahead market will allow Bonneville continued access to a range of trading partners, without increasing hurdles and barriers to transact, so it can continue to carry out its objectives in the day-ahead and real-time horizons.

Optimization

An organized day-ahead market brings together a variety of resources and loads and enables an optimization to dispatch those resources to serve loads at the least cost. Both buyers and sellers can achieve economic benefit. Dispatched resources are compensated at their bid or higher for the energy they offered to supply. Resources that are not dispatched are given a concrete price signal to either conserve their resource for future periods of higher demand or offer a more competitive bid if they wish to be awarded. Loads can economically bid in day-ahead to indicate a price at which they are willing to purchase energy, and all loads are ultimately served in real-time through the least-cost economic dispatch. The optimization allows for a broader and more transparent exchange of pricing information. Compared to the bilateral world of today, where there are numerous information asymmetries, a market optimization can provide participants, including Bonneville, with access to a more transparent picture of regional operations and tradeoffs, which aids both financial transactions and operational awareness.

In addition, joining a day-ahead market will give Bonneville better access to resources and loads across a broader footprint compared to bilateral markets. This allows for more flexible resources to respond to the needs of loads across that footprint. For resources with significant ramping capabilities, such as Bonneville's hydro resources, the more granular awards and dispatches of an organized market benefit both customers and the region more broadly.

Reliability

As a BA and a Transmission Operator (TOP), Bonneville is tasked with operating the electric grid in a reliable manner. Bonneville may utilize participation in an organized day-ahead market to reliably operate the grid. The market operator has a much wider view of transactional activity and grid operation compared to that of each individual BAA. Prior to real-time, the day-ahead market operator can forecast load needs and transmission constraints (i.e., areas on the transmission grid that may end up operating at their maximum transfer capacity based on expected system conditions), and award resources in a manner that honors those constraints in the day-ahead and real-time horizons. The market operator can also redispatch generation to reliably and most economically serve load (e.g., by supplying energy from a different resource

²⁶ See WECC, Reliability Implications of Expanding the EIM to Include Day-Ahead Market Services: A Qualitative Assessment (Sept. 2020), available at <https://www.westernenergyboard.org/wp-content/uploads/WECC-report-reliability-implications-of-expanding-EIM-to-include-day-ahead-market-services.pdf>.

that relieves a transmission constraint).²⁷ This ability of the market operator may reduce the likelihood and magnitude of transmission curtailments by Transmission Service Providers (TSP)/TOP.

Energy Resources

Bonneville has pledged to respond to customers' requests for integration of energy resources through the Evolving Grid initiative.²⁸ According to WECC's 2024 State of the Interconnection report, entities in the Western Interconnection plan to build close to 172 gigawatts (GW) of resources in the next 10 years. Addressing the changing resource mix and load shapes will be more successful through improved operation and coordination among many BAAs. An organized day-ahead market offers broader access to a larger portfolio of resources, which will enhance reliability because the market operator may dispatch resources within the broader market footprint.²⁹

Timeliness

While many commenters have called for a delay in Bonneville's day-ahead market policy decision, for reasons including for additional time to comment, to allow EDAM governance to continue to develop, to conduct government-to-government consultation, and to conduct further economic analysis, Bonneville must declare a policy direction now. Strategically, Bonneville's timeline allows better coordination with other Bonneville efforts such as Provider of Choice, allows Bonneville an "early seat at the table" for participation in Markets+, places Bonneville on a similar timeline to other entities in the West who are joining day-ahead markets, and maintains two viable market options. In addition, it is necessary for Bonneville to provide clear expectations to its customers, sovereigns, and stakeholders now to mitigate uncertainty and to collaborate on next steps.

2.4. Day-Ahead Market Framework

A day-ahead market is a centrally organized financial and physical electricity market where participants submit hourly resource offers and bids for load. The market optimization combines all offers and bids to determine the least cost energy dispatch to serve load while recognizing physical system constraints. If the market optimization determines the offers and bids to be economical, the participant receives a financially binding award. The resource offers can be updated with the market operator to reflect operational changes, with the ultimate real-time dispatches of resources serving all load economically given physical system conditions. Market participants ultimately receive settlements from the market operator for all resources and loads cleared through the market.

The market operator uses a SCUC and SCED³⁰ accompanied by a nodal network model with locational marginal pricing to create an optimized dispatch plan.³¹ "Unit commitment" determines the optimal

²⁷ See Mareldi Ahumada-Paras, Michael Mastrandrea, and Michael Wara, Stanford Climate and Energy Policy Program, *Grid Regionalization in the West: Reliability Benefits from Increased Cooperation in Electricity Markets and Operations* (Aug. 2024), available at https://woods.institute.stanford.edu/system/files/publications/Woods_Grid_Regionalization_White_Paper_v05_WEB.pdf.

²⁸ See Declaring a National Energy Emergency, Exec. Order No. 14156, 90 Fed. Reg. 8433, 8434 (Jan. 20, 2025).

²⁹ See WECC, Reliability Implications of Expanding the EIM to Include Day-Ahead Market Services: A Qualitative Assessment (Sept. 2020) at 3, available at <https://www.westernenergyboard.org/wp-content/uploads/WECC-report-reliability-implications-of-expanding-EIM-to-include-day-ahead-market-services.pdf>.

³⁰ As a reminder, SCUC stands for security-constrained unit commitment and SCED stands for security-constrained economic dispatch.

³¹ See FERC, Security Constrained Economic Dispatch: Definitions, Practices, Issues, and Recommendations: A Report to Congress Regarding the Recommendations of Regional Joint Boards for the Study of Economic Dispatch Pursuant to Section 223 of the Federal Power Act as Added by Section 1298 of the Energy Policy Act of 2005, available at <https://www.ferc.gov/sites/default/files/2020-05/final-cong-rpt.pdf>.

combination of resources to bring online from those that are available for some or all of the operating day.³² “Economic dispatch” determines the optimal output of all committed resources relative to bid-in or expected load and other resource output forecasts to minimize total cost to serve load.³³ To ensure that the unit commitment and economic dispatch are feasible, the optimization is “security-constrained,” which means that the optimization must adhere to certain limits (known as “constraints”) such as flow across transmission elements and maximum ramp rate of generators. For instance, if increasing the output of a generator that is otherwise economic to serve load would cause flow on a transmission element to exceed its limit, the optimization will instead increase the output of the next least-cost resource that does not cause the flow on that element to exceed its limit.

To incorporate these constraints into the optimization, the market operator has a full nodal network model showing the locations and relevant characteristics of all transmission elements and generation resources of a certain size as well as approximations to represent load across the area. The market operator receives updated constraint information in day-ahead and real-time data submittals from market participants and reliability entities. Transmission Operators and BAs update constraint information on the elements or system areas that have new or existing limitations. Resource Owners/Operators submit hourly offer information about the minimum and maximum amount of generation they are willing to sell and the associated price between those output levels, as well as resource limitations (e.g., ramp rate, minimum or maximum run time when committed, etc.).

For day-ahead optimization, the SCUC and SCED solve simultaneously across all 24 hours of the next operating day. For real-time optimization, the SCED solves for a set number of sub-hourly intervals for the applicable operating hour. In between the day-ahead optimization and the real-time optimization, the market operator runs additional SCUCs.³⁴ These intra-day SCUCs are used to ensure enough generation is online and available to serve expected load as input information changes, such as load forecast increases or an unexpected outage on a previously committed generation resource.

Finally, the market produces financial settlements for all energy traded and load ultimately served. Settlements are for all location-nodes for day-ahead and real-time resources generated and load demand, as well as other associated payments or charges. All centrally organized markets in the U.S. settle based on LMPs, which generally represent the incremental cost to serve another megawatt (MW) of load at a given location. LMPs are composed of the following pricing components: energy, losses, and congestion. In a day-ahead market framework, the award from the day-ahead solution is settled at the day-ahead LMP and is used as the financial reference point for settlement of energy in the real-time solution.

3. Public Process

In July 2023, Bonneville started its public process to evaluate day-ahead market participation including hosting 11 public workshops (see below for a list of workshops and their respective topics) to share and discuss potential benefits and risks. A high priority for Bonneville is ensuring that customers and stakeholders understand the day-ahead market proposals and have multiple opportunities to provide substantive feedback on the decision. Bonneville has accepted public comments and concerns and posted all the written comments on its day-ahead market process website.³⁵ Stakeholder comments have provided valuable information about concerns and issues and have had a direct impact on the decision process. Bonneville appreciates the robust engagement and the feedback it has received.

³² CAISO, Technical Bulletin 2009-06-05, Market Optimization Details § 2 (Nov. 19, 2009), *available at* <https://www.caiso.com/Documents/TechnicalBulletin-MarketOptimizationDetails.pdf>.

³³ *Id.* § 3.

³⁴ Referred to as “Reliability Unit Commitment” in Markets+ and “Residual Unit Commitment” in EDAM.

³⁵ Bonneville Power Administration, Day-Ahead Market, *available at* <https://www.bpa.gov/learn-and-participate/projects/day-ahead-market>.

Additionally, Bonneville coordinated with customers in the Provider of Choice public process to design power products that will be compatible with a day-ahead market for October 1, 2028 through September 30, 2044 contract period.³⁶

Topics covered in the public workshops include:

No.	Meeting Date	Topics
1	July 14, 2023	• Why are we exploring day-ahead market participation? • Overview of public engagement for establishing a Bonneville policy direction on potential day-ahead market participation • Discussion on drafting Bonneville day-ahead market evaluation principles • Overview of day-ahead markets
2	September 11, 2023	• Update on day-ahead market development & update on developing GHG accounting in a day-ahead market • Bonneville will continue to supply electric power to customers in a day-ahead market • Draft day-ahead market evaluation principles • Review of comments received • Section 5(b) of the Pacific Northwest Electric Power Planning and Conservation Act (Northwest Power Act)³⁷ (Section 5(b))/day-ahead market compatibility • Tabletop scenario work with the Public Power Council
3	October 23, 2023	• Energy and Environmental Economics (E3) overview of Western Market Exploratory Group (WMEG) cost/benefit study • Initial takeaways from WMEG Result • Considerations for Bonneville's day-ahead market business case analysis
4	November 29, 2023	• Discussion of Section 5(b) obligations/day-ahead market compatibility • Review of Bonneville's policy direction public process • Considerations for Bonneville's day-ahead market business case • GHG Update and consideration of GHG business case
5	February 1, 2024	• Update on Bonneville's decision process and timeline for CY 2024 • Review of Bonneville's day-ahead market evaluation and decision criteria • Update on Bonneville's day-ahead market public comment tracking • Responses to public comments at this workshop
5.5	May 3, 2024	• Tabletop scenario refresh (from workshop 2) • Workshop 6 scenarios
6	May 8, 2024	• Review of Bonneville's Staff Recommendation on Day-Ahead Market Participation; update on decision process and timeline for CY 2024 • Baseline process and scenario discussions

³⁶ See Bonneville Power Administration, Provider of Choice (Post-2028), available at <https://www.bpa.gov/energy-and-services/power/provider-of-choice>.

³⁷ 16 U.S.C. § 839c(b).

7	June 3, 2024	• Review of Bonneville’s comments on Pathways April 10 proposal and legal analysis • High-level congestion rent scenario • Congestion rent design • Congestion revenue scenario with congestion rights
8	July 18, 2024	• Update on the Pathways initiative • Day-ahead market from the transmission perspective
9	November 4, 2024	• Timeline update and key dates for CY 2025 • Update on Markets+ FERC filing and EDAM engagement • Transmission update • Bonneville’s continued decision process • Evaluation of market governance developments • Bonneville’s supplemental production-cost analysis/result interpretation
10	January 29 & 30, 2025	• Review of Bonneville’s day-ahead market decision process • E3 Case Result – Hydro Operational Limitations Scenario • Expected transmission revenue impact • Day-ahead market participation & implementation fees • Day-ahead market seams, reliability and operational impacts
11	March 19, 2025	• Opportunity to ask clarifying questions of the draft policy

Based on stakeholder feedback, Bonneville also considered potential day-ahead market participation through the lenses of firmness of power supply and certainty of delivery. This Policy addresses firmness of power supply in section 6.2, focusing on ensuring adequate supply through resource planning. Certainty of delivery is addressed in section 6.7, which describes how a day-ahead market paradigm would build upon existing constructs. Section 5.2.5 on GHG accounting addresses how market designs can provide for transparent accounting of environmental attributes.

4. Day-Ahead Market Evaluation Process

Bonneville has been evaluating potential day-ahead market participation based on eight evaluation principles. This section provides further detail for each evaluation principle.

4.1. Discussion of Evaluation Principles

While potential benefits, like those listed in section 2.3, are an important part of Bonneville’s evaluation, there are additional considerations for Bonneville to weigh in its evaluation. In its decision process, Bonneville is assessing the business case for day-ahead market participation based on both quantitative and qualitative evaluation components. Bonneville assessed day-ahead market participation based on the following evaluation principles. These principles were shared with stakeholders in public workshops and include revisions based on stakeholder feedback:

- Statutes – Bonneville meets its statutory, regulatory, and contractual obligations.
- Reliability – Bonneville maintains efficient, economical, and reliable delivery of power and transmission service to its customers.
- Reliability – Market design includes resource sufficiency and/or resource adequacy frameworks that ensure reliability.
- Business – Bonneville’s participation is supported by a sound business rationale.

- Strategy – Bonneville’s participation is consistent with Bonneville’s 2024-2028 Strategic Plan.
- Governance – The market has a durable, effective, and independent governance structure which provides fair representation to all market participants and stakeholders. Decision-making and stakeholder engagement occur in a transparent and inclusive manner.
- Customers – Bonneville’s evaluation of day-ahead market participation includes transparent consideration of the commercial and operational impacts on its products and services.
- GHG – Bonneville will evaluate how participation will impact GHG emissions attributed to the federal system and its regional firm power customers’ ability to comply with applicable state carbon programs. Participation must maintain the value of the low-carbon nature of the federal system to the extent possible.

The sections below highlight how a day-ahead market meets our evaluation principles.

4.1.1. Statutes – Bonneville meets its statutory, regulatory, and contractual obligations.

Bonneville has not identified any legal barriers to day-ahead market participation. See Appendix A for a discussion of Bonneville’s statutory authority to participate in Markets+.

4.1.2. Reliability – Bonneville maintains efficient, economical and reliable delivery of power and transmission service to its customers.

Maintaining the reliability of the power and transmission systems for all of Bonneville’s customers is one of the most important aspects of Bonneville’s various roles. Indeed, reliability is foundational to accomplishing many of the other principles, objectives, and goals upon which Bonneville focuses.

Day-ahead markets and market operators do not assume any of the reliability roles of a utility. Bonneville will retain its reliability roles, such as Transmission Planner, BA, and TOP, and remain responsible for compliance with applicable NERC reliability standards. Further, Bonneville and its federal generating partners maintain full control of federal resources, including authority to manage output and make energy available to the market. Thus, Bonneville will continue to serve its direct role in operation of the federal power and transmission systems and maintaining system reliability.

As described in Section 2.3, participating in a day-ahead market will provide Bonneville opportunities to support or improve reliability due to system optimization and geographic diversity benefits. As Bonneville moves into a day-ahead market implementation phase, Bonneville will continue to assess any potential reliability concerns, identify and design necessary mitigations, and work with the market operators to ensure the markets are able to support those mitigations where necessary.

4.1.3. Reliability - Market design includes resource sufficiency and/or resource adequacy frameworks that ensure reliability.

Bonneville believes that it is important for a day-ahead market to address long-term Resource Adequacy (RA) as well as short-term resource sufficiency. Resource sufficiency generally refers to resources’ availability to produce power (energy and capacity) to serve the expected load in the short term (e.g., moving into the next week, day or hour). RA generally refers to long-term planning and acquisition of resources, if needed, to serve the expected peak or critical load in a season or upcoming year. RA aims to have enough “steel in the ground” (resources built and accessible) to serve a forecasted peak load, while resource sufficiency considers the current operational landscape (e.g., outages or derates, up-to-date variable generation and load forecasts, etc.). The two concepts work in concert to minimize scarcity, emergency, or loss-of-load events.

In a day-ahead market, market participants continue to be responsible for their own RA and sufficiency, and thus they are obligated to bring a resource portfolio (including power purchases) able to meet their

expected load to the market; the market is then able to optimize the dispatch of resources, along with any independently-offered resources, creating a more efficient and economical load service plan reflecting the current system landscape. Market design frameworks try to ensure that market participants are held accountable for this responsibility to receive the shared benefits of an integrated market through penalties or limitations on market access.

Both day-ahead market options include an evaluation for resource sufficiency. EDAM has a set of resource sufficiency evaluation tests and Markets+ has a must-offer obligation, both of which compare an entity's day-ahead load and uncertainty requirements to its available resources to ensure they have sufficient resources to meet their loads or are held accountable. However, as explained further in section 5.2.2, Bonneville prefers the design in Markets+, primarily because it also includes a long-term RA requirement. Markets+ includes a standardized RA requirement, requiring all load responsible entities (LREs)³⁸ to participate in the Western Resource Adequacy Program (WRAP) administered by the Western Power Pool. While the CAISO BAA has its own RA framework, this framework is not extended to other entities outside of CAISO's BAA in general, and the EDAM design does not include a requirement for entities to participate in any RA program. Bonneville believes that Markets+ requiring participation in WRAP, a standardized RA framework, will better meet this principle.

4.1.4. Business - Bonneville's participation is supported by a sound business rationale.

With the emergence of day-ahead market offerings by both CAISO and SPP, most entities in the Western Interconnection are evaluating participation in an organized day-ahead market. While economic value is an important factor, a decision about day-ahead market participation encompasses many considerations beyond just economic value.

Production Cost Modeling (PCM) provides an initial analysis of various simulations. Bonneville joined WMEG and contracted with E3 to explore the economic possibilities. In Section 5.1 Bonneville describes the benefits and limitations of the PCM studies. However, for the evaluation of a day-ahead market, a sound business rationale must encompass factors beyond the short-term economic results. The long-term industry trends must also be considered. These trends could include more entities joining day-ahead markets, new variable energy resources integrating into the system which causes power purchase changes, and the potential development of an RTO. Joining a day-ahead market allows Bonneville to continue to align with the majority of the industry on the business of power markets.

4.1.5. Strategy - Bonneville's participation is consistent with Bonneville's Strategic Plan.

The "Evolving Grid" sets the agency's path for the Pacific Northwest, including the use of Bonneville's transmission system. Through the evolution, Bonneville will maximize the value of the federal hydropower and transmission systems. As the needs of its customers evolve, so must the products and services it offers. Bonneville must address customer demand for more renewable generation and amplifying RA concerns brought about by a changing resource mix. An objective in meeting this goal is fostering market evolution to enhance the delivery of cost-effective, reliable power and transmission service while modernizing business systems and processes. The flexible and reliable power of the Federal Columbia River Power System (FCRPS), coupled with the expansive high-voltage transmission grid, is the bedrock Bonneville will build on to meet these future needs.

4.1.6. Governance – The market has a durable, effective, and independent governance structure which provides fair representation to all market participants and stakeholders. Decision-making and stakeholder engagement occurs in a transparent and inclusive manner.

Bonneville performed a rigorous assessment of day-ahead market offerings from a governance perspective because insufficient independence and limitations on stakeholder engagement pose risks to creating a fair

³⁸ A Load Responsible Entity (LRE) is an entity directly responsible for ensuring an electrical load is served.

and equitable market that brings equitable value to all participants. Risks arise from market governance that retains authority for a single state, entity, or customer class.

At the highest level, the decision-making body for the market must be free of disproportionate obligation to the policies of a single state, entity, or customer class to ensure that market design is on an equal footing for all participants, including Bonneville. In CAISO markets, Bonneville has observed disadvantages for market participants outside of California during market design development and in times of outlier events.³⁹ The staffing and process for decision development and stakeholder engagement should equitably weigh the policies or priorities of all states, entities, and customer classes. Bonneville finds that the governance structure for Markets+ meets that standard.

As it engaged in the stakeholder processes for the development of both markets, Bonneville strongly advocated for the inclusion of sound independent governance principles in market design. Bonneville believes its efforts have positively impacted the governance structures of both EDAM and Markets+.

4.1.7. Customers - Bonneville's evaluation of day-ahead market participation includes transparent consideration of the commercial and operational impacts on its products and services.

Bonneville has conscientiously considered the needs of its large customer base as it evaluated joining a day-ahead market, including public customer/stakeholder workshops⁴⁰ exploring how a decision to participate in day-ahead markets may impact different customer types and how its various power and transmission products and services may work in a day-ahead market. Bonneville also collaborated with customers to design a long-term power sales contract⁴¹ that includes provisions to adapt to potential day-ahead markets to ensure the flexibility to meet a changing landscape. Further, in the public processes for EDAM and Markets+ development, Bonneville advocated for policies and designs to unlock additional value from the federal hydropower and transmission systems that benefit Bonneville and its customers.

Bonneville expects to continue holding day-ahead market public workshops. It will also work through various day-ahead market specifics in its rate cases and tariff terms and conditions proceedings, contract negotiations, business practice change forums, etc., as appropriate. Throughout these various processes, Bonneville will continue to comprehensively address the impacts of day-ahead market participation on the products and services it offers to customers.

4.1.8. GHG - Bonneville will evaluate how participation will impact GHG emissions attributed to the federal system and our regional firm power customers' ability to comply with applicable state carbon programs. Participation must maintain the value of the low-carbon nature of the federal system to the extent possible.

Bonneville is not subject to any state GHG programs in the region. However, Bonneville customers have repeatedly expressed the importance of the low-carbon attributes of their power purchases from Bonneville.⁴² Bonneville markets power from the federal hydropower system, Columbia Generating station,

³⁹ Examples include wheel through priorities in August 2020 and greenhouse gas allocation market design.

⁴⁰ Bonneville Power Administration, Day-Ahead Market, available at <https://www.bpa.gov/learn-and-participate/projects/day-ahead-market>.

⁴¹ Bonneville Power Administration, Provider of Choice (Post-2028), available at <https://www.bpa.gov/energy-and-services/power/provider-of-choice>.

⁴² Examples of customer comments related to GHG emissions can be found in Bonneville's Final Energy Imbalance Market Close-Out Letter § 5.2.3 (Sept. 2021), available at <https://www.bpa.gov/-/media/Aep/projects/energy-imbalance-market/final-eim-close-out-letter.pdf> (full comments available at <https://publiccomments.bpa.gov/CommentList.aspx?ID=421>); Bonneville's Provider of Choice Policy Record of Decision § 8 (Mar. 2024), available at <https://www.bpa.gov/-/media/Aep/about/publications/records-of-decision/2024-rod/rod-20240321-bonneville-power-administration-provider-of-choice.pdf> (full comments available

and other resource acquisitions and market purchases. Today, market purchases are the only resources in the federal system to which state programs attribute emissions. These purchases are an important component of Bonneville's power supply and have historically comprised 3 to 10% of the FCRPS.

Organized markets change GHG accounting dynamics because, absent a GHG accounting design, the market does not specify which resources are dispatched to meet a particular load. For example, when Bonneville joined the EIM in May 2022, the volume of unspecified purchases included in Bonneville's federal system fuel mix slightly increased. This was due to increased transfers of energy to meet load imbalance between Bonneville's BAA and other BAAs, which states accounted for at an unspecified emission factor. Currently, WEIM only employs a GHG accounting mechanism to support implementation of California's cap-and-trade program.

Both EDAM and Markets+ developed mechanisms to support the implementation of carbon pricing programs generally including California's program and Washington's cap-and-invest program. Over 60% of Bonneville's long-term power sales are to customers in Washington and are subject to the state's cap-and-invest program as well as the state's Clean Energy Transformation Act. Bonneville also has customers in Oregon that are subject to Oregon's GHG reporting requirements. Bonneville has participated in day-ahead market GHG accounting conversations mindful of impacts to customers in those states with the goal of ensuring customers can continue to claim low-carbon attributes associated with power purchases from Bonneville. As discussed in section 5.2.5, Bonneville believes the Markets+ design better reflects environmental attributes related to its firm power sales to its customers.

5. Day-Ahead Market Participation Evaluation

Bonneville has spent over two years evaluating whether to join a day-ahead market, and if so, which of the two available day-ahead markets options Bonneville should join. With the principles described in Section 4 in mind, Bonneville has considered quantitative analyses, market design elements, footprint, and other relevant information in its evaluation. On the whole, Bonneville finds that joining a day-ahead market will result in benefits to its customers.

Bonneville contracted with E3 to analyze economic costs and benefits using PCM. The initial PCM results depicted a wide range of economic benefits for day-ahead market participation. Bonneville's assessment is that the forecasted benefits justify participation in either EDAM or Markets+. Subsequent sections of this document further discuss the initial PCM results as well as supplemental analysis Bonneville contracted for with E3.⁴³ These results should not be viewed with the expectation of achieving specific forecasted revenues. The PCM results are forecasts that can be influenced by other factors that may alter the projected outcome. For example, modifications to market design items such as Congestion Rent, Scarcity Pricing, or LMP computation can impact benefits. PCM models also do not account for qualitative elements such as differences in market governance structure that can also produce quantitative impacts.

Overall, the PCM results showed:

- Participation in the EDAM market produces the highest net cost benefit in the cases studied.
- Markets+ offers the lowest cost to serve load but also forecasts reduced generation revenue.

at <https://publiccomments.bpa.gov/CommentList.aspx?ID=480>); and in customer comments received to-date in Bonneville's Day-Ahead Market process (comments available at <https://www.bpa.gov/learn-and-participate/projects/day-ahead-market>).

⁴³ Energy and Environmental Economics, WMEG Cost Benefit Study (CBS), BPA Day-Ahead Market Participation Workshop presentation (Oct. 23, 2023), available at <https://www.bpa.gov/-/media/Aep/projects/day-ahead-market/e3-wmeg-benefits-study.pdf>; Energy and Environmental Economics, BPA WMEG Follow-up Analysis presentation (Nov. 4, 2024), available at <https://www.bpa.gov/-/media/Aep/projects/day-ahead-market/2024/E3Presentation-bpa-stakeholder-meetingnov4-2024.pdf>.

- Although the net cost looks favorable, remaining a WEIM-only participant carries significant risk not easily reflected in the quantitative case result.

As mentioned in section 4, one of the eight evaluation principles is governance. Bonneville is specifically looking for a market that has a durable, effective, and independent governance structure which provides fair representation to all market participants and stakeholders. Bonneville’s evaluation considers the relevant factors associated with governance structures under both Markets+ and EDAM to identify the best governance structure available for Bonneville’s decision regarding day-ahead market participation. RA and resource sufficiency are included in the reliability evaluation principle in market design. RA aims to have enough physical resources (both transmission and generation) to serve a forecasted peak load well into the future (often years or multiple months), while resource sufficiency considers the current operational landscape (outages or derates, up-to-date variable generation and load forecasts, etc.).

Price formation and market power mitigation ensures that market rules provide appropriate price signals, which compensate resources at prices that reflect both the value of the services that resources provide to the market and the operational conditions under which the resource is awarded. EDAM and Markets+ are broadly similar in the way they model constraints and manage transmission, with some key differences, particularly regarding allocation of congestion rents, which are described in section 5.2.4. The market design for GHG accounting—how resources and their associated emissions are assigned to market participants—is critical to ensuring Bonneville’s customers can continue to claim the low-carbon attributes of their federal system power purchases for applicable state programs or for their own utility purposes.

This section discusses the economic and market design benefits associated with Bonneville’s Policy direction to participate in Markets+ with emphasis on governance, RA and resource sufficiency, price formation and market power mitigation, transmission and congestion rent, and GHG.

5.1. Economic Costs/Benefits Analyses

As part of its day-ahead market evaluation, Bonneville assessed costs and benefits using PCM. PCM is an industry-standard approach for analyzing costs and revenues associated with energy trading and load service. PCM is explained below in section 5.1.1.1.

Many entities in the Western Interconnection, including Bonneville, employ PCM in their evaluations of day-ahead markets, in integrated resource planning, and when assessing long-term transmission expansion costs. Bonneville also included consideration of the economic impact to its Power and Transmission business lines, reflecting both the PCM results and additional considerations. Further, Bonneville has considered the implementation costs (both internal to the agency and those paid to the market operator) as well as on-going participation fees associated with the day-ahead market options. These analyses and considerations are discussed in this section.

5.1.1. Production Cost Modeling

Bonneville was part of two separate cost-benefit analyses using PCM as part of its day-ahead market evaluation. Bonneville joined the WMEG in the summer of 2022. WMEG is a group of 25⁴⁴ BAAs within WECC that came together to examine participation in day-ahead market offerings. WMEG hired E3 to provide PCM analysis for each respective BAA across varying market footprints and varying years (2026,

⁴⁴ The 25 WMEG members represented are AEPCO, APS, Avista, Balancing Authority of Northern California (BANC), Black Hills Energy, Bonneville, Chelan County PUD, El Paso Electric (EPE), Grant County PUD, Idaho Power Company, Los Angeles Department of Water & Power (LADWP), NV Energy, PacifiCorp, Public Service of New Mexico (PNM), Platte River power Authority, Public Service of Colorado (PSCO), Puget Sound Energy (PSE), Salt River Project (SRP), Tacoma Power, Tucson Electric Power (TEP), Tri-State Generation and Transmission Authority (TSGT), and Western Area Power Administration (WAPA), which was modeled in 5 separate areas (SNR, CRCM, LAP, WALC/DSW, and WAUW). The rest of the WECC was represented as non-WMEG.

2030, 2035). Following the WMEG analysis, Bonneville contracted directly with E3 in 2024 for supplemental analysis using the WMEG data set to test additional market footprints and sensitivities of a number of other variables. This section discusses both sets of PCM analyses.

5.1.1.1. What is Production Cost Modeling?

PCM is an industry standard simulation software tool that attempts to model a day-ahead market by producing a least-cost dispatch to serve load based on a set of static input data. PCM incorporates SCUC and SCED, which are the processes the day-ahead market uses to optimize participants' loads, resources, and transmission.⁴⁵ The analysis produces hourly generation dispatches and associated electricity production costs to serve load based on numerous operational inputs. Such inputs include loads, generation resources, weather, fuel, and transmission connectivity/constraints.

There are many underlying assumptions that must be made to model such a complex system. In particular, the study results are highly dependent on the composition of the market footprint (i.e., which load, generation, and transmission are included in the market optimization). Identifying a market footprint requires assumptions about which market a utility may choose to join. The footprint composition brings together the resources that will be optimized to serve load at the least cost and is constrained by the transmission connectivity that is utilized by the market to deliver all the footprint resources to load. Adjusting the market participants, and therefore changing the footprint, can offer additional load to be served, additional generators to serve load, and new transmission connectivity that expands the possible solutions of the market optimization. Therefore, the composition of the market is an important and influential component in PCM.

PCM must also assume the cost associated with transmission within a market (usually assumed to be zero) and transmission and other incremental "friction" between markets (sometimes called the "hurdle rate"). Hurdle rates represent the "friction" between markets, which could come in the form of actual costs associated with sales across markets, or as a representative cost representing the inefficiency of two separate optimizations (one for each footprint) as opposed to a single optimization. This could show up as price divergence between markets such that the price in one market must be high enough to incentivize exporting from the other market. Much like the footprint composition, the adjustment (i.e., reduction and variation) in the hurdle rate also proved to be a notable operational model input.

PCM is a powerful tool that relies on a range of assumptions to produce modeling results that provide direction and magnitudes of market participation outcomes. PCM comes with both strengths and limitations. It produces simulations that optimize dispatch of resources to meet demand at the lowest possible cost, facilitate long-term planning and investment decisions, inform policy making and potential regulatory impacts, and provide insight for market dynamics and analysis to help understand price trends and identify opportunities for cost savings. The limitations of PCM are discussed further in the section below.

5.1.1.1.1. Production Cost Modeling Limitations

PCM is a useful industry-standard tool, however, it is accompanied by certain limitations. In PCM, a range of assumptions are required to produce effective modeling. While PCM results are useful in providing market participation outcomes, these results do not represent an exact expected outcome. Moreover, while PCM is a valuable industry standard method to simulate friction and hurdle rates, it is prudent to acknowledge that actual real-world values of friction and hurdle rates may differ from simulated results because of the inherent complexity, uncertainty, and variability associated with the assumptions and data quality in the model. For example, some entities view long-term firm transmission cost as a sunk cost and therefore do not include it in their price evaluation in their decision of whether they transact between

⁴⁵ For information on day-ahead market processes, see section 2.4 above.

markets. Further, there is not a single value that uniformly represents the risk that sellers are willing to take on, and thus a modeled hurdle rate can never perfectly represent reality.

In the supplemental analysis, E3 ran case studies to simulate scarcity events through the application of stressed conditions.⁴⁶ Specifically, E3 applied stressed conditions to the following market footprints 1) Business-as-usual, 2) West-wide market, 3) Alt Split 4A (current market declarations). In the results of these cases, net costs showed a minimal decline and prices in the model did not rise nearly as significantly as would be expected.

The minimal change in forecasted benefits in the PCM results stand in stark contrast to real-world outcomes from recent events such as the 2024 Martin Luther King, Jr. (MLK) holiday weekend winter storm. During that short period of time, the region faced significant competition for available resources to meet load accompanied by hourly prices exceeding the WECC soft-offer cap of \$1,000 per megawatt-hour (MWh). There was also significant congestion on key transmission paths and congestion revenues within WECC exceeded \$100 million dollars. The 2024 MLK weekend event represents an extreme outlier that a PCM cannot replicate. A typical scarcity outlier, experienced over a few days to a week, will likely see multi-hour, peak load block prices rise to triple digits. Frequently, evening hourly prices will rise above this into the mid-to-high hundreds, sometimes exceeding the WECC soft-offer cap, as loads are peaking and renewable resources are ramping down. The pricing levels reflected in the PCM captured neither the extreme event like a 2024 MLK, nor the more typical scarcity event of sustained elevated prices. The PCM pricing outputs simply do not reach the magnitude nor the daily sustained level of pricing that we would expect to see, even under the stressed load parameters. The minimal decline in net cost results for stressed conditions in the PCM study demonstrates that the financial impacts of a scarcity event are not captured in the modeling. Regardless of day-ahead markets, such events occur, and Bonneville simply acknowledges that these risks are not fully represented in the PCM study.

Additionally, PCM studies do not reflect various market design elements such as GHG pricing programs, market power mitigation, out-of-market actions, and market bid caps. Lastly, PCM results cannot account for market design changes and modifications to market rules influenced by the market's governance structure. Bonneville explores a number of these design elements in section 5.2.

5.1.1.2. WMEG Study

Bonneville participated in WMEG with 24 other BAAs in a joint exploration of day-ahead market participation. The WMEG group sought economic analysis results that would help forecast costs and benefits associated with day-ahead market participation for each BAA participating in the study. E3 used PCM to develop categorical results, discussed below in section 5.1.1.2.2, for each BAA. The categorical results were summed together to create a single "net cost" number, which was intended to indicate whether costs or benefits were likely for a given BAA's participation in a day-ahead market. The PCM studies were modeled across three different time horizons of 2026, 2030, and 2035. The 2026 scenarios depicted initial day-ahead market launch. The 2030 scenarios assumed maturation of the day-ahead market by layering on some BAA consolidation and an ancillary services market. The 2035 scenarios modeled a full RTO, which consisted of a single consolidated BAA (however, it did not include any estimates of transmission cost savings). Load, generation, and transmission were also augmented in future cases, reflecting anticipated growth in each category. Each participating BAA received only their respective results, though they were free to share their results on a wider basis. Bonneville publicly released its WMEG PCM results in the fall

⁴⁶ Energy and Environmental Economics, BPA WMEG Follow-up Analysis presentation at 4, 11 (Nov. 4, 2024), available at <https://www.bpa.gov/-/media/Aep/projects/day-ahead-market/2024/E3Presentation-bpa-stakeholder-meetingnov4-2024.pdf> (Task 3: Low Water Year (+ Stressed Load)).

of 2023 in public workshop 3.⁴⁷

5.1.1.3. WMEG Data Elements

Each WMEG member provided generation, transmission, and load data to E3 for use in the PCM to model market activity and calculate categorical costs and benefits. This data was retained by E3 following the completion of the initial WMEG study and used in the supplemental analysis that Bonneville requested.

5.1.1.3.1. WMEG Cost Benefit Categories

The PCM results consisted of eight distinct categories: load costs, generation costs, reserve costs, reserve revenue, generation revenue, wheeling revenue, congestion revenue, and GHG revenue. It is important to emphasize that the results are reported such that costs are represented as positive numbers and revenues are represented as negative numbers (as indicated by the positive or negative sign in the category list below). The eight categories were then added together to create a “net cost,” which indicated whether the WMEG member should expect a cost or benefit. Again, a positive “net cost” indicated cost to the WMEG member because of day-ahead market participation, and a negative “net cost” indicated benefits to the WMEG member because of day-ahead market participation.

Net Variable Cost = Load Cost + Generation Cost + Reserve Cost – Reserve Revenue – Generation Revenue – Wheeling Revenue – Congestion Revenue – GHG Revenue

The following are the categories from the PCM results accompanied by their applicable sign:

PCM Results Categories (as defined in E3’s Western Markets Exploratory Group: Western Day -Ahead Market Production Cost Impact Study)⁴⁸

1. Load Costs (+)

Entities incur a cost to serve load based on (a) the hourly quantity of load (in MWh) that the entity is obligated to serve in each zone of the model times (b) the hourly zonal energy price

2. Generation Costs (+)

The model reports variable production costs for each generating unit as the sum of fuel costs, startup costs, and variable O&M cost for that resource. Generation Costs are attributed to each entity as (a) the total variable production cost of the unit times (b) the percentage share of that unit that is owned or contracted to the entity.

3. Reserve Costs (+)

In the Business-as-Usual (BAU) Case, E3 enforces ancillary service reserve requirements at the BAA level but does not settle these products at a market clearing price. For all the market cases, day ahead forecast error reserves are enforced at the level of a subregion within each market (e.g. the Northwest portion of Markets+), and each entity is assigned a Reserve Cost responsibility based on of (a) the hourly quantity of reserves that entity needs times (b) the hourly market price for reserves within that market sub-region.

4. Reserve Revenue (-)

Each entity is also awarded Reserve Revenue from the market based on (a) the quantity of reserves that are contributed by generators owned or contracted by the entity times (b) the hourly market price for reserves

⁴⁷ For results, see Bonneville Power Administration, Day-Ahead Market, available at <https://www.bpa.gov/learn-and-participate/projects/day-ahead-market> (see Workshops, Oct. 23, 2023, WMEG Materials).

⁴⁸ Energy and Environmental Economics, Western Markets Exploratory Group: Western Day Ahead Market Production Cost Impact Study at 9-11 (June 2023), available at <http://www.oasis.oati.com/woa/docs/NEVP/NEVPdocs/3. E3 WMEG Western Day Ahead Market Production Cost Impact Study - Final.pdf>.

within that market subregion. In the 2030 and 2035 CBA cases, Reserve Costs and Reserve Revenues are calculated separately for each reserve product (spinning reserves, non-spinning reserves, and regulating reserves, as well as day ahead forecast error reserves)

5. Generation Revenue (-)

Generation Revenue is first calculated for each resource based on (a) the hourly energy produced by the generator, times (b) the hourly price at the generator's zone. This Generation Revenue is then attributed to each entity based on the percentage share of each resource that is owned or contracted to the entity

6. Wheeling Revenue (-)

Wheeling revenue is revenue that transmission providers earn by selling transmission service. In the BAU Case, total Wheeling Revenue is calculated in the model for each entity based on the product of (a) the amount of energy exported over transmission lines connected to that entity, times (b) the OATT rate or market wheeling rate applicable that BAA or transmission entity, plus an additional \$/MWh charge for bilateral day ahead market friction. In the RT stage of the BAU Case, wheeling is not charged for transactions between entities in the WEIM or WEIS market. In the DA markets cases, total wheeling revenue is first determined at a market-footprint level based on the (a) amount of energy flowing exported over transmission lines connected to each market footprint times (b) the load-weighted average of OATT rates of zones participating in that market, plus an additional \$/MWh charge for transactional friction on seams between the markets. This total market wheeling revenue is then distributed among market participants based on each participant's percentage share of total load in the market (load-ratio share basis).

7. Congestion Revenue (-)

Price differentials between zones due to transmission constraints creates congestion between entities, resulting in loads paying higher prices than remote generators receive on the other side of congested interface. The value of this difference is assigned back to the entities in the BAU case and for lines within each market footprint. Congestion on the border of each market is allocated among all participants in that market on a load ratio share basis.

8. GHG Revenue⁴⁹ (-)

Revenue associated with any MW of generator output that was attributed as an import into a state with a pricing program (CA/WA). The way Bonneville elected to model its resources in the E3 studies resulted in minimal attribution of imports.

9. Net Cost (+) OR (-)

The difference between the Net Variable Costs for an entity in a market case compared to that entity's Net Variable Revenues.

5.1.1.3.2. Bonneville's Modified Calculation of Net Cost

As Bonneville examined the PCM results, it became evident that certain categories could be set aside, and a net cost could be recalculated with the remaining categories. Bonneville set aside generation cost, reserve cost, and reserve revenue because they were a static or negligible value, meaning there was zero or almost zero difference among scenarios. Further, after some conversation with E3 regarding wheeling revenue, Bonneville and E3 determined that the study approach did not attempt to capture existing transmission contracts. Instead, it assumed that all transactions outside of or between markets required incremental purchase of transmission and that all transactions within a market required no purchase of transmission. These assumptions do not approximate likely transmission purchase patterns for Bonneville customers and therefore do not appropriately reflect a likely outcome of market participation. Therefore, Bonneville

⁴⁹ The text of Result Category No. 8 has been modified from the E3 report for clarity.

removed the wheeling revenue category from the net cost computation when analyzing the PCM results.⁵⁰ Based on the negligible value category exclusions and wheeling revenue exclusion, the results discussed throughout the rest of this document focus on PCM results for load costs, generation revenue, congestion revenue, and GHG revenue, and a net cost summing those four categories (reported as “Net Cost without Wheeling” for clarity). Bonneville separately provides an analysis of the potential impact to transmission revenues in section 5.1.1.7.

Net Cost = Load Cost – Generation Revenue – GHG Revenue – Congestion Revenue

5.1.1.3.3. WMEG Footprints

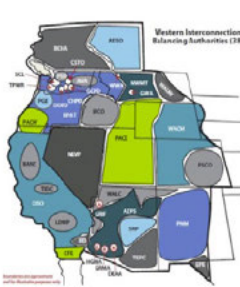
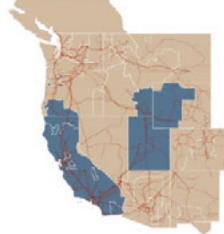
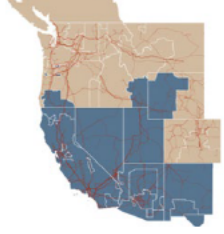
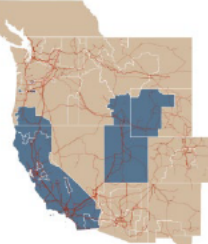
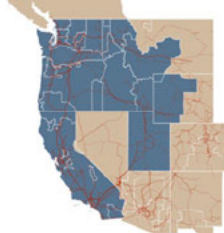
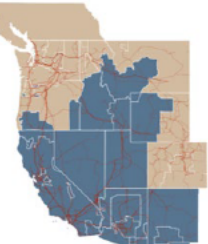
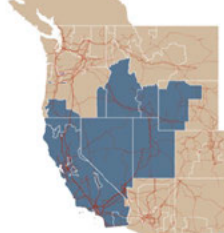
Of the 38 BAAs in WECC, spanning from Canada to Mexico, 25 participated in the WMEG study. In all cases except for a “business as usual” (BAU) case, each BAA in WECC was designated to fall within one of two categories to comprise a day-ahead market footprint:

- 1) The BAA participates in EDAM,
- 2) The BAA participates in Markets+

During the initial 2023 PCM analysis, WMEG members designed a number of footprint scenarios representing the footprints that they determined were most plausible to test the impacts of different market footprints on the benefits. WMEG also included a BAU scenario to represent continued bilateral trading without any entities joining a day-ahead market. These footprints are shown in Table 1 on the next page.

⁵⁰ Energy and Environmental Economics, BPA WMEG Follow-up Analysis presentation at 20.

Table 1 | Footprints used in WMEG studies

	Business-as-Usual This footprint was intended to model the operational and trading world as it exists today. Bilateral trading (no centralized market) in day-ahead; EIM & EIS cover most of WECC in real-time stage	 Main Split PacifiCorp (PAC) + all of California (including Western Area Power Administration Sierra Nevada Region (WAPA SNR)) in EDAM; rest of WECC in Markets+
	EDAM Bookend All US WECC in EDAM; British Columbia Hydro only in Markets+	 Alternative Split 1 PAC + California (excluding WAPA SNR) + SW (AZ + NM + NV) in EDAM; rest of WECC in Markets+
	Markets+ Bookend PAC, CAISO, Los Angeles Department of Water & Power, Turlock Irrigation District, Balancing Authority of Northern California (BANC) (not WAPA SNR) in EDAM; rest of WECC in Markets+ (including WAPA SNR)	 Alternative Split 2 PAC + California (including WAPA SNR) + NW (WA, OR, ID, NWMT) in EDAM; rest of WECC in Markets+
	Alternative Split 3 PAC + California (excluding WAPA SNR) + SW + ID + NWMT in EDAM; rest of WECC in Markets+	 Alternative Split 4 PAC + California (excluding WAPA SNR) + ID + NV in EDAM; rest of WECC in Markets+ [Same as Markets+ Bookend, but NV & ID move to EDAM]

5.1.1.3.4. Bonneville's WMEG PCM 2023 Results

Table 2 shows a summary of Bonneville's results across the footprint scenarios. The top half of the table reflects the categorical results as absolute costs (positive numbers) or revenues (negative numbers). The bottom half calculates the delta result for each scenario relative to the BAU scenario. Again, a positive number represents an increased cost or a decreased revenue (and is accompanied by a red dot), and a negative number represents a decreased cost or an increased revenue (and is accompanied by a green dot).

The full set of Bonneville’s initial WMEG results are available on Bonneville’s website.⁵¹

Table 2 | Bonneville's WMEG Results (Fall 2023, units in millions of dollars)

	A	B	C	D	E	F	G	H	I	J
1	Footprint									
2		Cost/Benefit Category	BAU (2026)	EDAM Bookend (2026)	Main Split (2026)	Markets Bookend (2026)	Alt Split 1 (2026)	Alt Split 2 (2026)	Alt Split 3 (2026)	Alt Split 4 (2026)
3	Category Value	Load Costs	921	944	924	902	919	982	840	861
4		Gen Costs	131	131	131	131	131	131	131	131
5		Gen Revenues	-1341	-1490	-1370	-1329	-1360	-1515	-1152	-1220
6		Congestion Revenues	-50	-60	-53	-53	-48	-49	-51	-48
7		GhG Revenues	0	0	-1	-1	-1	0	-1	-1
8		Net Costs w/o Wheel	-339	-475	-369	-349	-359	-451	-233	-277
9	Δ Category vs. BAU	Δ Load Cost		● 23	● 3	● -19	● -2	● 61	● -81	● -60
10		Δ Gen Revenue		● -149	● -29	● 12	● -19	● -174	● 189	● 121
11		Δ Congestion Revenue		● -10	● -3	● -3	● 2	● 1	● -1	● 2
12		Δ GhG Revenue		● 0	● -1	● -1	● -1	● 0	● -1	● -1
13		Δ Net Cost w/o Wheel		● -136	● -30	● -10	● -19	● -112	● 107	● 62
Green = Benefit Greater than BAU Red = Increased Cost from BAU										

Starting with the top half of the table, the PCM results forecast Bonneville to achieve net benefit in each of the eight cases in Table 2 (see row 8). Moving to the bottom half of the table, benefits greater than BAU are achieved in five out of seven footprints (all footprints except Alt Split 3 and Alt Split 4). Alt Splits 3 and 4 results forecast reduced benefits relative to BAU. While those footprints project significant cost savings in serving load,⁵² the reduction in projected benefits relative to BAU is driven by generation revenues declining⁵³ more than the load costs decline. The generation revenue declines are driven by lower marginal prices observed in these footprints, as Bonneville is a net exporter in the generation data provided, resulting in the impact to revenue outweighing the savings to load.

Notably, Bonneville determined that the BAU scenario studied by E3 assumes all utilities forgo day-ahead market participation and cannot account for what entities will do in the long term. As discussed above in section 5.1.1.2.4, the BAU case fundamentally assumes continued use of bilateral trading activity as the primary tool for energy trading and limited organized market activity (i.e., real-time only). With many entities in WECC evaluating participation and declaring intent to join organized day-ahead markets, the bilateral world, as it is today, is not expected to persist. Bonneville included modeled costs and benefits relative to BAU to provide a sense of the magnitude, and the direction of the impact day-ahead market participation has relative to today. BAU does not represent a realistic future scenario.

5.1.1.4. Bonneville’s Supplemental Cost/Benefit Analysis 2024

Bonneville engaged E3 to perform additional supplemental analysis to enhance its modeling and assumptions for its evaluation of potential day-ahead market participation. Following the release of the WMEG PCM results and review of stakeholder comments on Bonneville’s WMEG results, Bonneville requested E3 to assess additional market footprints and identified scenarios or variables. For the supplemental tasks that used years 2030 and 2035, there were no market maturation pieces layered on the analysis. The new studies applied only load growth, modifications to generation resources (e.g., new builds and retirements), and additions to the transmission grid (e.g., new transmission lines) to the respective year-based cases. The additional PCM analyses are listed below. The full set of Bonneville’s PCM results are

⁵¹ Bonneville Power Administration, Day-Ahead Markets available at <https://www.bpa.gov/learn-and-participate/projects/day-ahead-market>.

⁵² Alt Split 3 Load Cost reduced by \$81m as shown in cell I9; Alt Split 4 Load Cost reduced by \$60m as shown in cell J9.

⁵³ Alt Split 3 Gen Rev declines by \$189m as shown in cell I10; Alt Split 4 Gen Rev declines by \$121m as shown in cell J10.

available on Bonneville’s website.⁵⁴

Note: During the development and execution of the supplemental analysis, Bonneville and E3 identified an issue regarding data underlying the “generation revenue” category. The generation values supplied by Bonneville to E3 were reflective of all generation, including generation applicable to the Slice product. Bonneville and E3 decided to apply a 15% reduction to generation revenue results in the supplemental analysis to ensure generation revenue more accurately reflected Bonneville’s estimated share of generation. This reduction was discussed with all stakeholders during the public workshop on November 4, 2024.⁵⁵

5.1.1.4.1. Supplemental Analysis Tasks

- 1) (Single West-wide Market) | Compute PCM cost benefit values for Bonneville for the EDAM Bookend Footprint for 2030 and 2035.
- 2) Lower Market to Market Hurdle Rates | Adjust the Market-to-Market hurdle rates by running three sensitivities that progressively reduce the hurdle rates.
- 3) Low Water Year (& Stressed Conditions) | Compute PCM cost benefit values for Bonneville for reduced hydro resources due to poor rain and snowpack. Model increased loads to mimic stressed conditions resulting from a multi-day heat and multi-day cold event.
- 4) Bonneville WEIM-Only | Compute PCM cost benefit values for Bonneville where Bonneville decides not to participate in a day-ahead market but remains a participant in CAISO WEIM. Neighboring and adjacent BAAs proceed with day-ahead market participation.
- 5) Additional Transmission Capacity | Compute PCM cost-benefit values for Bonneville where transmission connectivity between the Pacific Northwest and the Desert Southwest is increased.
- 6) Potential Capacity Value | Estimate the range of potential capacity benefits associated with day-ahead market participation.
- 7) Market Seam at California Border | Compute PCM cost benefit values for Bonneville where only entities lying within the state boundary of California participate in EDAM.
- 8) Alt Split 4A – Market Declarations | Compute PCM cost benefit values for Bonneville utilizing a two-market footprint that reflects the current market declarations and leanings.
- 9) Alt Split 2NV Pacific Northwest & Nevada join | Compute PCM cost benefit values for Bonneville where the Pacific Northwest, California, Nevada, and PAC BAAs are modeled as participants in EDAM while the Desert Southwest BAAs are modeled in Markest+.

Supplemental Analysis that was identified but unable to be modeled in PCM - No results were provided by E3

- 1) Market Interactions with WRAP | Understanding the potential difference in ability of either market’s rules & practices to enable realization of RA benefits.
- 2) GHG Regulation | Understanding the impact that Markets+ vs. EDAM rules regarding GHG import treatment and pricing specific to the treatment of resources contracted to load in a GHG zone.

5.1.1.4.2. Supplemental Analysis Footprints

The supplemental analysis used several of the initial WMEG footprints in conjunction with the new footprints in Table 3. Each new footprint was added for a specific reason. Alt 2NV was designed to represent a more realistic scenario in which Bonneville is in EDAM while the Desert Southwest, which is unlikely to

⁵⁴ Bonneville Power Administration, Day-Ahead Markets available at <https://www.bpa.gov/learn-and-participate/projects/day-ahead-market>.

⁵⁵ *Id.*

join EDAM, is in Markets+. Alt 4A was designed to reflect utilities' market declarations and publicly stated leanings available at the time of the analysis. The Non-California West-wide Market footprint was added to see what west-wide benefits could be realized without the complexities presented in attempting to address CAISO's governance. These three additional footprints were used in various combinations with some of the above tasks, but not all additional footprints were tested for every task above.

Table 3 | Updated footprints for additional E3 studies

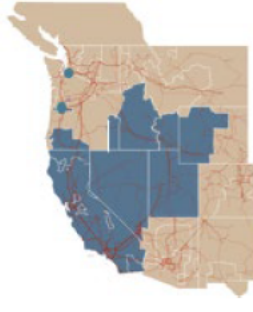
Alternative Split 2NV	Alternative Split 4A
 EDAM: California, PacifiCorp, NV Energy & all Pacific Northwest BAAs Markets+: BAAs located in the Desert Southwest and Rockies	 EDAM: California, PacifiCorp, NV Energy, Idaho Power, Portland General Electric, Seattle City Light Markets+: Rest of US WECC and British Columbia <i>Reflects current day-ahead market declarations & leanings</i>
Non-CA Westwide Markets+	
 EDAM: California LSE's Only Markets+: Rest of US WECC and British Columbia	

Table 4 | Supplemental PCM Case Results⁵⁶

- Section 1 of the table shares the raw case results by category for each of the supplemental analysis cases supplied by E3.
- Section 2 calculates the delta for each category of each case against anchor point BAU.
- Section 3 calculates the delta for each category of each case against anchor point Alt Split 4A.
- Positive numbers are costs and negative numbers are benefits.
- Red dots indicate a cost increase between the case and the anchor point.
- Green dots indicate a benefit increase between the case and the anchor point.

Table 4 | E3 Supplemental PCM results | Δ Supplemental case vs BAU | Δ Supplemental case vs Alt Split 4A

		Supplemental Analysis																					
		Cost/Benefit Category	BAU (2026)	T9 Alt Split 4A (2026)	T2 Alt Split 4A M2M (2026)	T2 Alt Split 4A M2M2 (2026)	T2 Alt Split 4A M2M3 (2026)	T2 Main Split M2M (2026)	T2 Main Split M2M2 (2026)	T2 Main Split M2M3 (2026)	T3 BAU Low Water (2026)	T3 BAU Low Water & Stressed Loads (2026)	T3 Alt Split 4A Low Hydro (2026)	T3 Alt Split 4A Low Hydro & Stressed Loads (2026)	T3 EDAM Bookend Low Water (2026)	T3 EDAM Bookend Low Water & Stressed Loads (2026)	T4 Alt Split 4A BPA EIM ONLY (2026)	T4 Alt Split 4A BPA EIM ONLY Low Stress Load (2026)	T4 EDAM Bookend BPA EIM ONLY Low Hydro Stress Load (2026)	T5 Alt Split 4A Straw (2026)	T5 Hypothetical New Additional TX (2026)	T10 Non-CA WestWide M+ (2026)	T11 Alt Split 2NV (2026)
E3 Supplemental PCM Results	Load Costs		921	739	818	874	910	961	981	983	1104	1132	957	1001	1043	1067	908	1109	1018	780	811	890	873
	Gen Costs		131	131	131	131	131	131	131	131	131	131	131	131	131	131	131	131	131	131	131	131	131
	Gen Rev**		-1140	-835	-987	-1097	-1166	-1231	-1365	-1279	-1201	-1218	-1032	-1067	-1184	-1201	-1129	-1203	-1203	-1104	-977	-1162	-1158
	Congestion Rev		-50	-65	-59	-56	-57	-52	-54	-57	-30	-30	-39	-39	-39	-38	-69	-31	-31	-58	-88	-46	-44
	GHG Rev		0	0	0	0	0	-1	-1	-1	-1	0	0	-1	-1	0	0	0	0	0	0	0	0
Net Cost w/o Wheel			-138	-30	-98	-148	-182	-192	-208	-222	4	15	16	26	-50	-42	-160	5	14	-61	-123	-207	-195
Δ BAU vs Supplemental Case	Δ BAU Load Cost			-182	-103	-47	-11	40	60	62	183	211	36	80	122	146	-13	188	97	-141	-110	-31	-48
	Δ BAU Generation Rev			305	153	43	-26	-91	-125	-139	-61	-78	108	73	45	62	11	-63	36	226	163	-42	-15
	Δ BAU Congestion Rev			-15	-9	-6	-7	-2	-4	-7	20	20	11	11	11	12	-19	19	19	-8	-38	4	6
	Δ BAU GHG Rev			0	0	0	0	-1	-1	-1	0	0	-1	-1	0	0	0	0	0	0	0	0	0
Δ BAU Net Cost w/o Wheel				108	41	-10	-44	-54	-69	-84	142	153	154	164	89	96	-22	143	152	78	15	-69	-57
Δ Alt Split 4A vs Supplemental Case	Δ Alt 4A Load Costs		182		79	136	171	222	242	245	366	393	218	262	305	328	169	371	280	42	72	151	134
	Δ Alt 4A Gen Rev		-305		-152	-262	-301	-397	-430	-445	-366	-384	-198	-232	-350	-367	-294	-369	-270	-79	-142	-347	-320
	Δ Alt 4A Congestion Rev		15		6	9	8	13	11	8	35	35	28	26	27	27	4	34	34	7	-23	19	21
	Δ Alt 4A GHG Rev		0		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	Δ Alt 4A Net Cost w/o Wheel			-108		-67	-118	-152	-161	-177	-192	35	45	47	56	-19	-12	-129	36	44	-30	-92	-177

Green = Benefit Greater than anchor point Red = Increased Cost than anchor point
 **Generation Revenue has been reduced by 15% to reflect slice revenue reduction

Table 5 | Consolidated supplemental case results for Alt Split 4A, Alt Split 4A WEIM Only, Alt Split 2NV, Alt Split 4A M2M, Alt Split 4A M2M2, and Alt Split M2M3

⁵⁶ During the development and execution of the supplemental analysis, Bonneville and E3 identified an issue regarding the “Generation Revenue” category. The load values provided by Bonneville to E3 reflected the preference load that Bonneville serves. The Generation values supplied by Bonneville to E3 were reflective of all generation including generation applicable to the Slice product. Bonneville and E3 decided to apply a 15% reduction to Generation Revenue results in the supplemental analysis to ensure Generation Revenue reflected Bonneville’s estimated share of generation. This reduction was discussed with all stakeholders the public workshop 9 on November 4, 2024.

	A	B	C	D	E	F	G
	BPA Day-Ahead Market →	Markets+	No DAM Market WEIM-Only	EDAM	Markets+	Markets+	Markets+
1		Alt Split 4A (2026)	Alt Split 4A BPA WEIM-Only (2026)	Alt Split 2NV (2026)	Alt Split 4A M2M (2026)	Alt Split 4A M2M2 (2026)	Alt Split 4A M2M3 (2026)
2	Cost/Benefit Category	Declining Hurdle Rates					
3	Load Costs	739	908	873	818	874	910
4	Gen Rev	-835	-1129	-1155	-987	-1097	-1166
5	Gen Costs	131	131	131	131	131	131
6	Congestion Rev	-65	-69	-44	-59	-56	-57
7	GhG Rev	0	0	0	0	0	0
8	NC w/o Wheel	-30	-160	-196	-97	-148	-182
9	Δ Alt 4A Load Costs	--	● 169	● 134	● 79	● 136	● 171
10	Δ Alt 4a Gen Rev	--	● -294	● -320	● -152	● -262	● -331
11	Δ Alt 4A Congestion Rev	--	● -4	● 21	● 6	● 9	● 8
12	Δ Alt 4A GhG Rev	--	● 0	● 0	● 0	● 0	● 0
13	Δ Alt 4A Net Cost w/o Wheel	--	● -130	● -166	● -67	● -118	● -152
14	Δ Alt 4A M2M's vs Alt Split 4A WEIM-Only Net Cost w/o Wheel	--	--	--	● 63	● 12	● -22
15	Δ Alt 4A M2M's vs Alt Split 2NV Net Cost w/o Wheel	--	--	--	● 99	● 48	● 14

These PCM cases were the most stakeholder-cited cases in responses to the Draft Policy.

Supplemental Case Results⁵⁷

On the next page, Bonneville discusses the results from the supplemental analyses. In each case, the figures show raw case results and do not reflect differences against any other study case, though the original BAU result is plotted for reference. Negative numbers represent forecasted benefit, and positive numbers represent forecasted costs.

Figure 2 | All Supplemental Case Results

Figure 2 plots each of the supplemental case results together on a single chart. 2026 case results are depicted with circles, 2030 case results are depicted with triangles, and 2035 case results are depicted as diamonds. Yellow and orange denote dry water years and dry water years accompanied by stressed loads. Purple shades denote modifications to hurdle rates in the model.

⁵⁷ Energy and Environmental Economics, BPA WMEG Follow-up Analysis presentation (Nov. 4, 2024), available at <https://www.bpa.gov/-/media/Aep/projects/day-ahead-market/2024/E3Presentation-bpa-stakeholder-meetingnov4-2024.pdf>.

Figure 2 | E3 PCM results

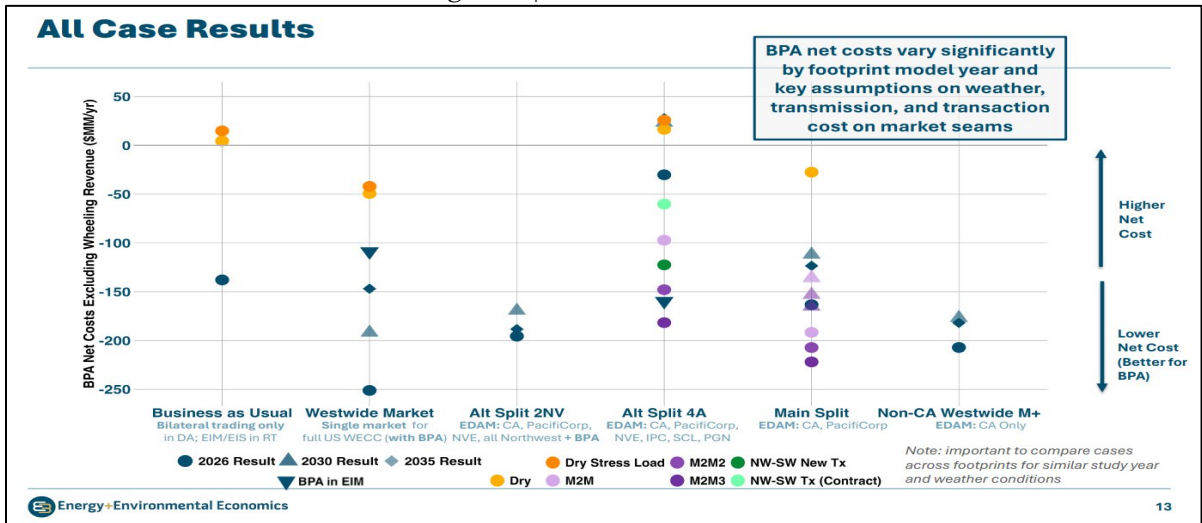


Figure 2 Takeaway: Range of possible outcomes depending on various factors.

This graph shows the comparative impact of individual variables against each other. The graph illustrates an array of potential outcomes impacted by footprint composition, transmission connectivity, and other tested sensitivities. While Figure 2 plots all supplemental case results, not all case results are discussed in detail in the following sections. West-wide Market, Main Split, and Non-CA West-wide M+ are not feasible footprints due to market participation declarations already issued by BAAs.

Figure 3 | 2026 Base Footprint Results

Figure 3 plots 2026 supplemental case results including the new footprints as defined above plotted against some of the original WMEG footprints. We see that both the Alt Split 2NV case and the Non-California West-wide Market result in benefits above the BAU case, whereas Alt Split 4A results in benefits less than the BAU case.

Figure 3 | E3's 2026 Results

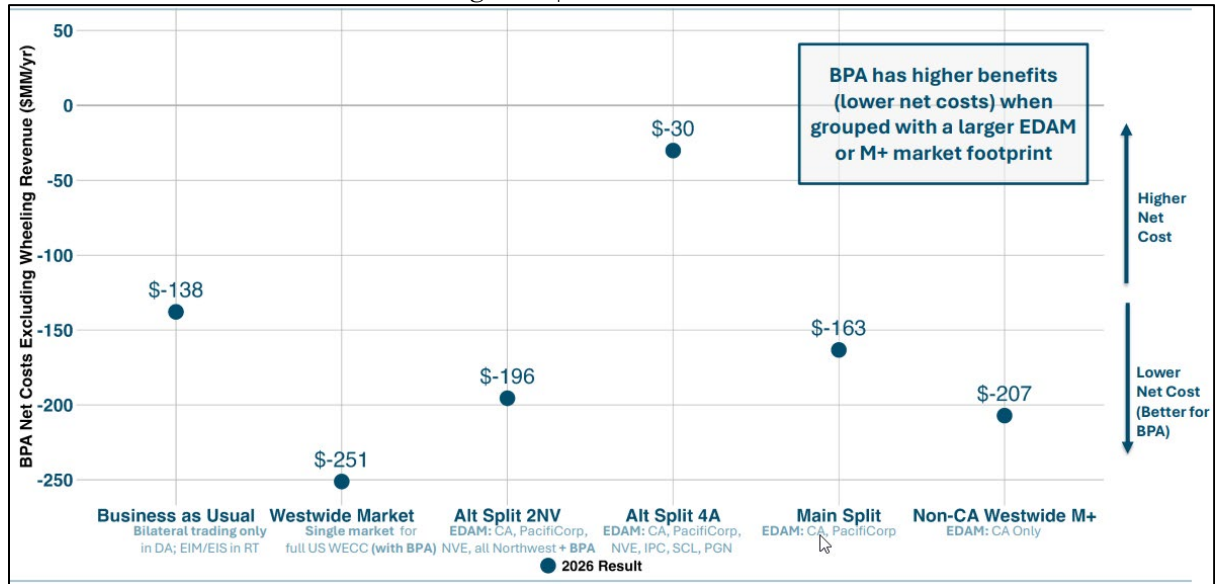


Table 6 | Alt Split 4A vs BAU

	N	O	R
1			
2	Cost/Benefit Category	BAU (2026)	T9 Alt Split 4A (2026)
3	Load Costs	921	739
4	Gen Costs	131	131
5	Gen Rev	-1140	-835
6	Congestion Rev	-50	-65
7	GhG Rev	0	0
8	Net Cost w/o Wheel	-138	-30
9			
10	Δ BAU Load Cost		-182
11	Δ BAU Generation Rev		305
12	Δ BAU Congestion Rev		-15
13	Δ BAU GhG Rev		0
14	Δ BAU Δ Net Cost w/o Wheel		108

Table 7 | Alt Split 2NV vs BAU

	N	O	AK
1			
2	Cost/Benefit Category	BAU (2026)	T11 Alt Split 2NV (2026)
3	Load Costs	921	873
4	Gen Costs	131	131
5	Gen Rev	-1140	-1155
6	Congestion Rev	-50	-44
7	GhG Rev	0	0
8	Net Cost w/o Wheel	-138	-195
9			
10	Δ BAU Load Cost		-48
11	Δ BAU Generation Rev		-15
12	Δ BAU Congestion Rev		6
13	Δ BAU GhG Rev		0
14	Δ BAU Δ Net Cost w/o Wheel		-57

Figure 3 Takeaway: Footprint is a primary driver of results.

As discussed previously, the PCM results are highly dependent on the market footprint. Because Bonneville is a net exporter in the generation input data provided, footprints with higher LMPs, particularly during times of surplus hydro, result in increases to generation revenue that outstrip the increases to load cost. We see this in the Alt Split 4A results, where load costs go down by \$182 million (see cell R10), but generation revenues go down by more (\$305 million, see cell R11). Alt Split 2NV seems to balance this impact. The results show a smaller decrease to load costs than Alt Split 4A (\$48 million, see cell AK10), but an increase to generation revenue (\$15 million, see cell AK11). This is likely due to the timing of price fluctuations.

It is not possible to predict with absolute certainty which footprint will ultimately materialize. As seen in Figure 2 and Table 2, the initial and supplemental PCM analyses resulted in a range of cost or benefit outcomes. Given that there are two day-ahead market options in the region, both with substantial support from various entities across the West, Bonneville determined that it is best to look at the results for footprints with multiple markets. Based upon the information and the modeled footprints available, Bonneville sees Alt Split 4A (see Table 6) as the most realistic footprint with Bonneville in Markets+ and Alt Split 2NV (see Table 7) as the most realistic footprint with Bonneville

in EDAM.

Alt Split 4A is a two-market scenario that divides participation between EDAM and Markets+. Geographically, Markets+ is divided into two regional areas. The first being the Pacific Northwest and the second being the Desert Southwest. EDAM participants are forecasted to lie between these two regional areas, creating a geographic division. The Net Cost without Wheeling Revenue forecast is an annual benefit of \$30 million (as noted in Table 2 T9 – Alt Split 4A 2026), which is a decrease from the BAU case. The decline in benefit appears to be driven by a notable drop in Generation Revenue. Interestingly, this case also forecasts significant savings in Load Cost. Both the Generation Revenue decline and Load Cost savings are the product of lower locational marginal prices in Markets+ (relative to BAU). This footprint demonstrates the dichotomy between seeking the lowest cost to serve load and seeking to maximize value for surplus generation. Bonneville must weigh the challenges of seeking the greatest revenue value for surplus generation, while recognizing that customers may also benefit from the lowest costs to serve load.

Alt Split 2NV is a two-market scenario in which Bonneville, the Pacific Northwest, California, Nevada, and PacifiCorp's service territory are depicted as EDAM participants. Entities located in the Desert Southwest are modeled as Markets+ participants. This footprint creates geographical division, but, unlike in Alt Split 4A, each market maintains contiguous transmission connectivity. The Net Cost without Wheeling Revenue forecasts a benefit of nearly \$200 million. When compared to BAU, Alt Split 2NV forecasts to be nearly \$60 million better. Examining the categorical differences between cases shows that \$48 million in Load Cost savings is driving the forecasted benefit.

Figure 4 | Base Footprint Results & WEIM-Only Results

Figure 4 plots 2026 supplemental case results and layers on the two WEIM-only scenarios that were modeled. In the WEIM-only cases, Bonneville remains outside day-ahead markets while continuing to be a WEIM participant, and the other entities in WECC participate in the day-ahead market in varying footprints. The WEIM-only option was evaluated for the West-wide Market footprint and Alt Split 4A footprint. (Note that Bonneville had not yet developed the Alt Split 2NV footprint for use in this task, so it was not modeled.) The arrows indicate the change in benefit to Bonneville of remaining a non-day-ahead market participant in the respective cases. Specifically, benefits for the West-wide market footprint decline from \$251 million to \$109 million. Conversely, Alt Split 4A sees an increase in benefit from \$30 million to \$160 million should Bonneville remain solely a WEIM participant. These are raw case results and do not reflect differences against any other study case.

Figure 4 | WEIM-only scenario

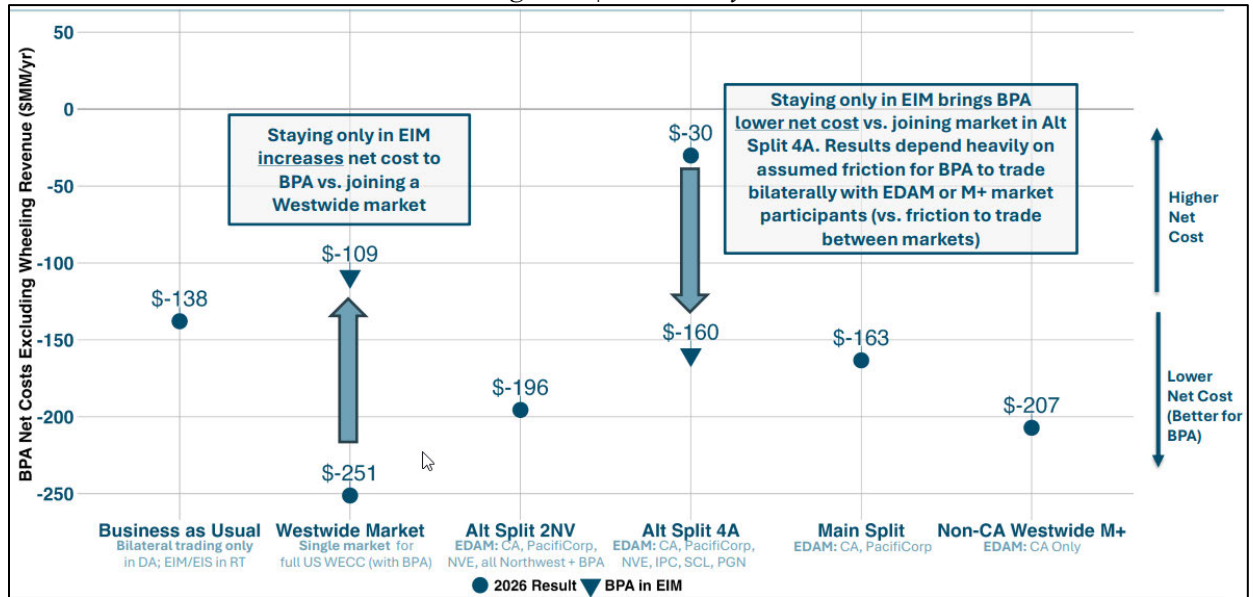


Figure 4 Takeaway: WEIM-only benefits appear positive but the analysis does not consider long-term viability questions.

The results suggest Bonneville achieves benefit remaining outside of a day-ahead market, depending on the footprint. Compared to BAU, Bonneville would achieve benefits slightly greater than those in the current bilateral world if the Alt Split 4A footprint otherwise materializes. Comparing this WEIM-only case to that of Bonneville participating in Markets+ suggests that Bonneville achieves greater benefit by staying out of a day-ahead market. Alternatively, if the West-wide Market footprint materializes and Bonneville remains WEIM-only, Bonneville is modeled to see less benefit than being in EDAM and less benefit than BAU. However, these results cannot be viewed in a vacuum. Bonneville stresses that a significant limitation in these results is the assumption of a simple hurdle rate to access either market, which does not reflect the potential for decreased liquidity in the bilateral markets or increased friction to access either market as those markets grow. In addition, the reduction in access to trading partners may significantly degrade these results and make remaining a WEIM-only participant an unsustainable option in the long term.

Figure 5 | Base Footprint Results & Changing Hurdle Rates

Figure 5 plots 2026 supplemental case results testing multiple sensitivities of market-to-market (M2M) hurdle rates. The hurdle rates cases are noted in shades of purple (with lighter color representing a higher hurdle rate and darker color representing a lower hurdle rate) and were applied to Alt Split 4A and the Main Split footprints. The arrows indicate change in benefit for the respective cases. Both footprints demonstrate increased benefit as the hurdle rates are lowered. These are raw case results and do not reflect differences against any other study case.

As a reminder, hurdle rates are costs affiliated with transacting from one market to another. If no hurdle rate existed in the model, the market dispatch results would effectively be co-optimized results (like a single market footprint). This case study proposed to progressively lower the market-to-market hurdle rates with each new sensitivity. This was simulated through adjustment to transmission costs.

Table 8 | Hurdle Rate Descriptions & Value for M2M Cases

Hurdle Rates - Markets+ Footprint Exports						
WMEG	Supplemental Analysis					
	M2M		M2M2		M2M3	
	DA	Weighted Average OATT +\$6 adder	DA	Weighted Average OATT + \$3 adder	DA	50% of Weighted Average OATT + \$3 adder
	M2M DA = \$10.50/MWh		M2M2 DA = \$7.50/MWh		M2M3 DA = \$5.25/MWh	
	RT	Weighted Average OATT + \$3 adder	RT	Weighted Average OATT + \$3 adder	RT	50% of Weighted Average OATT + \$3 adder
\$14.50 /MWh in DA & RT	M2M RT = \$7.50/MWh		M2M2 RT = \$7.50/MWh		M2M3 DA = \$5.25/MWh	

* Adder encompasses value for Friction & Congestion Risk

Figure 5 | Hurdle Rate Sensitivities

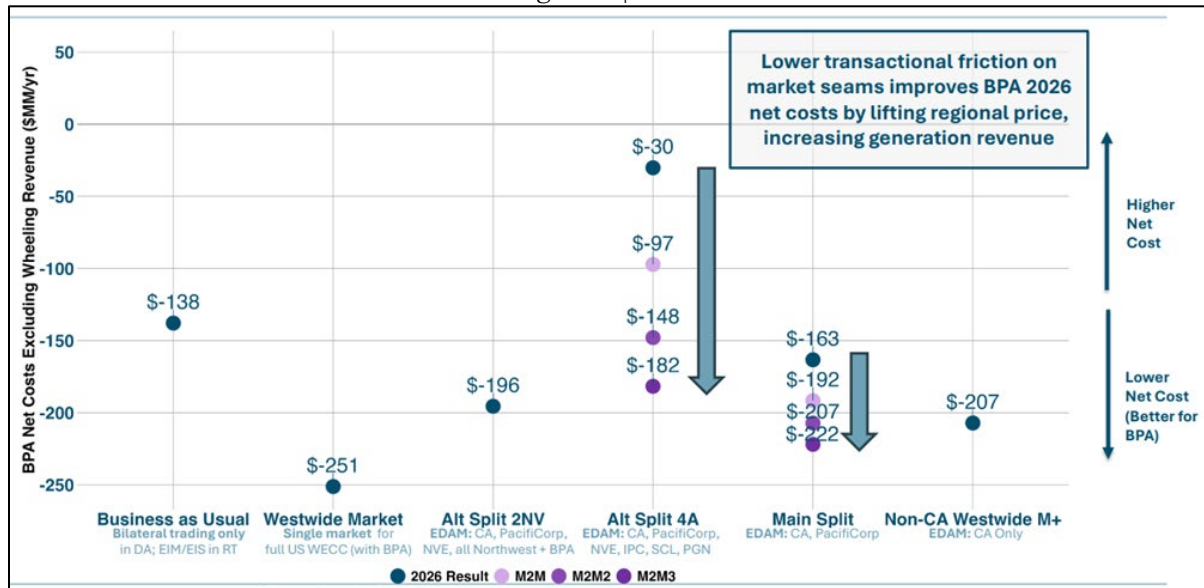


Figure 5 Take-away: Hurdle rates drive differences in footprint benefits; Bonneville can achieve benefits above BAU, including with the current expected Markets+ footprint.

In both footprints tested, Bonneville's results improve with each reduction in the hurdle rate. For the Alt Split4A footprint, all three sensitivities forecast benefits for Bonneville. Two of the three cases forecast benefits greater than BAU. This suggests that Bonneville can achieve incremental net benefits in Markets+ in the Alt Split 4A footprint if it can still access EDAM with minimal friction, and that Bonneville would benefit from working to minimize that friction with both market operators. FERC recently noted that while seams are sure to materialize the market operators, BAAs, and stakeholders should coordinate to develop solutions that minimize friction at the seams. Bonneville concludes that lower hurdle rates are more likely than those initially modeled in the WMEG studies, providing better information that participating in Markets+ participation will result in benefits above business-as-usual.

Figure 6 | Base Footprint Results & Changing Timeline

Figure 6 plots 2026 supplemental case results and layers on future year scenarios which include augmentation of load, generation, and transmission (but do not include any changes to market design). Results for 2030 are plotted with triangles and results for 2035 are plotted with diamonds.

Figure 6: Cases over time 2026-2035

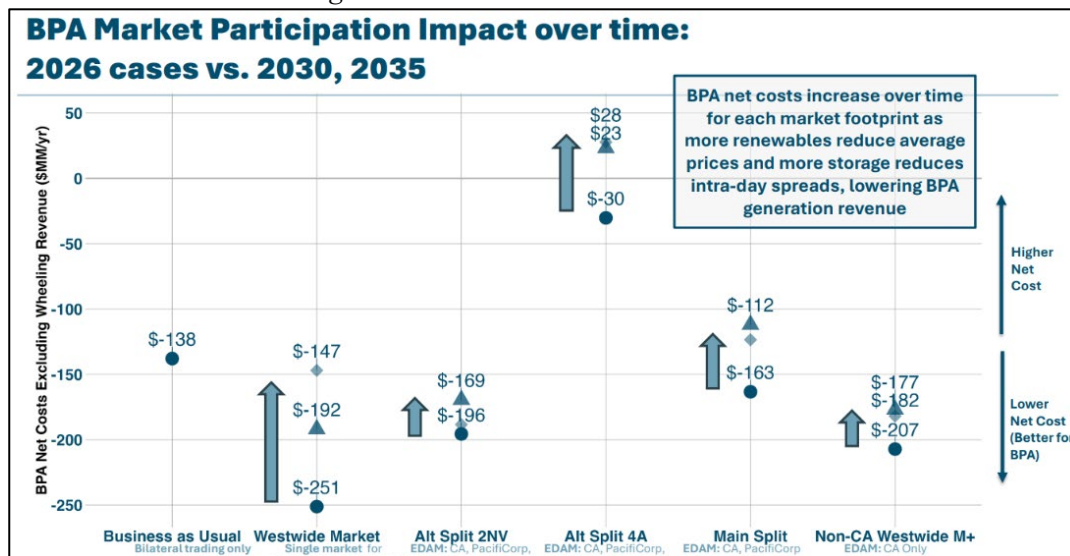


Figure 6 Takeaway: Changing regional resource mix may result in declining benefits over time.

The supplemental PCM analysis also produced study case results for future years of 2030 and 2035. An interesting trend emerged when comparing the case study footprints from 2026 to 2035. In each footprint tested, forecasted Net Costs increase for Bonneville. As time progresses, benefits continue to decline. E3 identified this trend as the result of continued renewable resource participation and the expansion of storage resources. These resource additions result in reduced intra-day price spreads, limiting the value of shapeable hydro. Bonneville would see increased competition from those additional resources within the market and is unable to capture the same amount of Generation Revenue as depicted in early case results.

5.1.1.5. Concluding thoughts on PCM results

PCM results provide general direction (i.e., cost or benefit) and magnitude around market participation. The models offer an array of outcomes that are strongly impacted by the modelled footprint and hurdle rate.

Context for Magnitude of Benefits

To put these numbers in context, Bonneville's Fiscal Year 2026 Power Revenue Requirement is \$3,451,708,000,⁵⁸ and provides the basis for recovering generation-related costs associated with the Federal Columbia River Power System (FCRPS), including the federal investment in hydro generation, fish and wildlife, conservation costs, non-federal power supply, and market purchases.⁵⁹ Bonneville's Fiscal Year 2026 Transmission Revenue Requirement is \$1,626,696,000,⁶⁰ and provides the basis for rates to Federal Columbia River Transmission System (FCRTS) costs, including recovery of the federal investment in transmission and transmission-related assets, operations and

⁵⁸ Power Revenue Requirement Study Documentation - BP-26-E-BPA-02A Table 1A.

⁵⁹ Power Revenue Requirement Study - BP-26-E-BPA-02.

⁶⁰ Transmission Revenue Requirement Study Documentation - BP-26-E-BPA-09A TABLE 1-1.

maintenance and expenses associated with transmission and ancillary services.⁶¹

Bonneville's Power revenue uncertainty, largely driven by its power net secondary revenue uncertainty, has a standard deviation of approximately \$250 million per year and a range of \$2.2 billion.⁶² This is not to diminish the significance of potential increased costs to Bonneville, but it is an important frame to place around the overarching strategic decision, the various other market design considerations, and the highlighted limitations of the PCM results. The general range of potential costs or benefits generated by Bonneville's PCM results of ~\$150 million. This amounts to roughly +/- 3% of Bonneville's annual revenue requirement. This falls within Bonneville's range of Bonneville's net secondary revenue uncertainty.⁶³

Participation in EDAM

Participation in EDAM produces the highest Net Cost benefit in the cases studied. However, examination of the sub-categories comprising the Net Cost illustrates that there are tradeoffs. Higher locational marginal prices drive up Generation Revenues in EDAM cases. The higher prices also result in greater cost to serve load. While Bonneville aims to maximize secondary revenue from surplus generation, it also aims to serve load at the lowest cost. Further, there is no guarantee Bonneville will continue to have significant surplus generation available to market, so the higher projected costs to serve load in EDAM may not always be offset by higher revenue associated with surplus.

Remaining a WEIM-only participant

Remaining a WEIM-only participant, which would require continued reliance on bilateral trading in all time-horizons prior to real-time, carries risks not easily reflected in the PCM. As discussed in section 2.3, staying outside a day-ahead market as other participants join presents risks to bilateral liquidity and introduces additional barriers to access trading partners.⁶⁴ Market participating entities are expected to focus on trading in their respective day-ahead markets and may be unwilling to or limited in the extent they can transact outside the market in the day-ahead time frame. Bonneville anticipates that convincing trading partners to trade bilaterally, instead of offering their resource to the market, may require a premium. This dynamic makes the longevity of remaining solely a WEIM participant unclear.

Participating in Markets+

Markets+ offers lower cost to serve load but also forecasts reduced Generation Revenue. Similar to participating in EDAM, there is tension created between the objectives of serving load at least cost and maximizing surplus revenue. The market hurdle rate sensitivity cases add further context, as they indicate that in the right conditions, Bonneville may achieve benefits greater than BAU.

Overall Takeaways

These PCM results provide good indicators of direction and magnitude regarding day-ahead market participation. However, these results should not be viewed with the expectation of achieving specific forecasted dollars. The PCM results are forecasts that can be influenced by other factors that may alter the projected outcome. For example, modifications to market design items such as Congestion Rent, Scarcity Pricing, or Locational Marginal Price

⁶¹ Transmission Revenue Requirement Study - BP-26-E-BPA-09A. BP-26-E-BP-05A.

⁶² BP-26-E-BP-05-CC01, Power and Transmission Risk Study, at 89 Table 1: Rev Sim Net Revenue Statistics for FY 2026 through FY 2028; *see also* Transmission Revenue Requirement Study Documentation, BP-26-E-BP-05A.

⁶³ Power and Transmission Risk Study, BP-26-E-BPA-05-CC01, at Table 1 (RevSim Net Revenue).

Power and Transmission Risk Study, BP-26-E-BP-05-CC01, at 89, Table 1 (Rev Sim Net Revenue Statistics for FY 2026 through FY 2028); *see also* Transmission Revenue Requirement Study Documentation, BP-26-E-BP-05A.

⁶⁴ *See* WECC, Reliability Implications of Expanding the EIM to Include Day-Ahead Market Services: A Qualitative Assessment, available at <https://www.westernenergyboard.org/wp-content/uploads/WECC-report-reliability-implications-of-expanding-EIM-to-include-day-ahead-market-services.pdf>.

computation can impact benefits. PCM models also do not account for qualitative elements such as differences in market governance structure, nor do they account for the way in which governance structure can impact market design, which impacts quantitative outcomes.

Bonneville views the PCM results as one component of a much larger decision framework for day-ahead market participation. While the PCM results are useful, they alone do not lead to a direct conclusion about which market participation decision Bonneville should make. These PCM results must be used in conjunction with the principles that Bonneville has proposed to inform a day-ahead market decision. The market design aspects discussed in section 5.2 provide important considerations for the broader potential benefits of Markets+ participation.

As explained earlier, one limitation of PCM is that it does not account for impacts to various types of power and transmission customers. The next section discusses Bonneville's proposed direction to continue assessing economic impacts.

5.1.1.6. Business Line Economic Impacts

Day-ahead market growth in the region is expected to impact Bonneville's costs, revenues, trading activity, and net secondary revenue volatility. While Bonneville's decision around day-ahead market participation will affect these impacts, changes are expected to occur regardless of whether Bonneville pursues day-ahead market participation. Bonneville is unable to forecast the financial impact around rates, products, and the volatility for any option prior to issuing its day-ahead market Policy.⁶⁵ This is because the specifics needed to conduct financial analysis, such as final market design, footprint, seams agreements, etc. are not yet known. Inventory and market price risk represent key drivers of overall financial risk to Bonneville, which exist in both bilateral and organized markets.

Most of the quantitative economic analysis on day-ahead market options were performed by E3 using PCM that produce a cost-benefit analysis. This analysis provides insight into the potential economic effect of different day-ahead market footprint options and a high-level evaluation of the overall economic effect on Bonneville. While informative, it does not provide the full range of inputs needed for Bonneville's finance models to show the full impact to setting and modeling rates nor the risk around those costs and revenues. Quantitative evaluation and modeling within both Power and Transmission Services also inform the range of financial impacts to both business lines, and to Bonneville as a whole. However, given what was modeled, Bonneville can understand some of the large drivers for costs and revenues.

5.1.1.7. Power Services

Joining a day-ahead market means that all resources and loads are served through the market clearing process. If customers or other utilities join a day-ahead market as their own market participant (Markets+) or Scheduling Coordinator (EDAM), they will bid and settle their own resources with the market and will have their load settled with the market operator directly. If a Bonneville customer is not a direct market participant, they will not be directly exposed to the day-ahead market settlements; instead, any financial impacts would be passed on through Bonneville rates.

In the context of what that means for cost-based rates, Bonneville will continue to conduct rate proceedings as described in Appendix A, and forecasted Net Secondary Revenue (NSR) will remain a meaningful component of calculating rates. The two main drivers of Bonneville's NSR forecasts in rates are Riverware modeling (forecasted hydro inventory) and Aurora modeling (forecasted energy prices). Aurora modeling results are frequently driven by price expectations for natural gas, and the fuel for frequent marginal resources in the modeling runs. These key drivers of NSR expectations will not be affected by Bonneville's decision to join a day-ahead market, as they will be subject to the same fundamentals regardless of day-ahead market participation. For example, the key drivers that influence prices, such as load demand, hydro inventory, and natural gas prices are fundamental conditions that will drive prices in bilateral markets as well as organized markets. Therefore, the forecasting of these drivers of NSR,

⁶⁵ See sections 5.1.1.6 and 5.1.1.7 below for a discussion of impacts to Power and Transmission customers.

which feed into rate proceedings, are not expected to change with a day-ahead market decision.

NSR represents a forecast of what Bonneville reasonably expects or targets for revenue outside of its long-term contract sales to preference customers (see section 6.7). In addition to continuing to provide long-term contracts, Bonneville expects that it will continue to conduct some level of bilateral forward transacting, however, frequency, volume, and terms may change with the evolution of markets within the region. Instead of bilateral trading in the day-ahead timeframe, Bonneville will see resources and loads cleared through the day-ahead market. As is the case today, actual NSR will deviate from rate case expectations, with the difference being reflected as an increase or decrease to Bonneville's financial reserves. Any financial impacts from day-ahead market participation will be a non-itemized portion of NSR to ensure consistency with the Bonneville objective of maximizing the value of its entire generation portfolio by optimizing across all market options.

The key area of difference introduced is that instead of bilateral transactions in the day-ahead timeframe, Bonneville will trade through the market, introducing financial settlements for resources and loads. In the same way that Bonneville must manage inventory and market price risk presented by regional fundamentals, Bonneville will continue to optimize the system through both commercial and operational actions, while minimizing risks. This will continue to be managed closely to minimize costs and maximize revenue for customers, as done today in the bilateral markets.

5.1.1.8. Transmission Services

The evolution of markets in the Pacific Northwest is ushering in day-ahead markets that will impact Bonneville as a BA and TSP. Just as the WEIM required Tariff, Rates, and Business Practice changes, the day-ahead market will require changes as well. This will affect both Network Integration Transmission Service (NITS) customers and Point-to-Point (PTP) transmission service customers. Bonneville needs to ensure that customers continue to receive reliable service. Bonneville's transmission customers rely on Bonneville for delivery of resources to load, whether in Bonneville's BAA or as a path to another BAA.

As Bonneville has seen two day-ahead markets developing, it has become reasonably certain that several of Bonneville's current transmission customers will be in BAAs that have joined a day-ahead market, even if Bonneville does not move to the same or any day-ahead market. Because Bonneville's transmission will be used in day-ahead, real time, and bilateral markets, Bonneville recognizes concerns about potential transmission cost shifts between these different markets. Bonneville will propose changes to its rates, tariff, and business practices to align cost impacts with cost-causation and ensure customers are informed to adjust their respective future business models as needed to account for the new market paradigm.

Both CAISO and SPP realize that day-ahead markets introduce a potential reduction of both short-term and long-term transmission revenues to participating TSPs.^{66,67} This potential reduction results from the market design principle that all transmission of a participating TSP is available for the market to use, unless that transmission has been explicitly removed from the market's calculations. Because the market has access to all of the TSP's transmission, there is less incentive for entities to purchase transmission.

The E3 PCM analysis attempted to quantify the impact to transmission revenue, but Bonneville removed it from its PCM assessment.⁶⁸ Instead, Bonneville performed its own analysis on the potential impact that day-ahead market participation may have on its transmission revenue. Bonneville focused on PTP transmission because those customers mainly purchase PTP to wheel through Bonneville's BAA, while NITS customers mainly take service and remain in the Bonneville BAA. Bonneville assumed that sales of NITS transmission would remain the same.

⁶⁶ *Cal. Indep. Sys. Operator*, FERC Docket No. ER23-2686, Transmittal Letter at 22-23 (Aug. 23, 2023) ("CAISO EDAM Filing").

⁶⁷ *Sw. Power Pool*, FERC Docket No. ER24-1658, Transmittal Letter at 9-10 (Mar. 29, 2024).

⁶⁸ For more information on the removal of the "Wheeling Revenue" category from the PCM analysis, see section 5.1.1.2.3 above.

Bonneville estimated potential bookends for a potential decrease in transmission sales from \$20 million to \$200 million over time.⁶⁹ Fortunately, both Markets+ and EDAM have a mechanism to help the TSP recover some of the lost transmission revenues due to the day-ahead market; however, they are slightly different approaches.

Markets+ encourages transmission customers to retain and purchase long-term firm transmission rights through its congestion rent design that includes an allocation to transmission rights holders. This allocation allows a transmission customer to directly receive congestion rents if the customer holds firm PTP rights of monthly duration or longer or NITS rights (see section 5.2.4). The EDAM design does not provide the same direct allocation between OATT rights and congestion rents (see section 5.2.4), resulting in a less direct incentive for maintaining long-term transmission rights.

In addition to congestion rent, there are other incentives to maintain long-term firm transmission rights. These include transmission for load service, to meet the WRAP firm transmission requirement, and for interchange transactions importing, exporting, and wheeling through market footprints.

Furthermore, Bonneville has over 65 GW of long-term transmission service requests in its transmission queue, indicating significant demand that could mitigate potential losses of long-term firm sales. Although these customers can remove their requests, Bonneville has not experienced a reduction in its queue. If Bonneville did see a significant reduction of long-term revenues, Markets+ has a robust stakeholder process and governance model that would allow stakeholders to bring concerns up for review.

For the potential revenue loss associated with short-term transmission revenues, both the EDAM and Markets+ day-ahead market designs include a transmission revenue recovery mechanism allowing a participating TSP to recover the potential revenue loss resulting from releasing unsold available transfer capability (ATC) to the market. In Markets+, the Market Transmission Use (MTU) charge mitigates for short-term firm revenue losses, by allowing the TSP to recover the difference between its historical short-term revenue requirement and current short-term revenues.⁷⁰ The EDAM Access Charge provides a recovery mechanism for short-term revenue reductions, potential lost short-term revenues associated with future transmission capacity, and potential wheeling revenue shortfalls.⁷¹ The MTU will be applied in the same manner for all TSPs in Markets+. The EDAM Access Charge, however, will be applied differently for CAISO than for other EDAM Entities because of differences in transmission service offerings.⁷²

In summary, although participation in day-ahead markets may potentially reduce transmission revenues, both day-ahead market designs have mechanisms that help participating TSPs mitigate this impact. In addition, after entry into a day-ahead market, Bonneville will continue to monitor actual transmission revenue recovery and, if needed, advocate through the market stakeholder process for additional market design adjustments to mitigate any potential loss of transmission revenues.

5.1.2. Participation and Implementation Cost Estimates

Both EDAM and Markets+ have participation and implementation fees. Further, there would be implementation work associated with participation in either option. Cost estimates of each option are provided below. These are

⁶⁹ See Bonneville Power Administration, BPA's Public Engagement for Establishing a Policy Direction on Potential Day-Ahead Market (DAM) Participation – Workshop 10 at 15 (Jan. 29-30, 2025), available at <https://www.bpa.gov/-/media/Aep/projects/day-ahead-market/2025/dam-workshop-10-presentation-20250129.pdf>.

⁷⁰ SPP Markets+ Tariff, Attach. A § 7.11 (Market Transmission Use).

⁷¹ CAISO EDAM Filing, Attach. A-2 (Clean Tariff) § 33.26.1 (EDAM Access Charges).

⁷² For example, for potential wheeling revenue shortfalls “the EDAM transmission owner[] will be compensated for the transmission use that supports the excess wheeling at the EDAM transmission owner’s non-firm hourly point-to-point transmission rate or the CAISO participating transmission owner will be compensated for excess wheeling through transmission use at the applicable wheeling access charge transmission rate.” *Cal. Indep. Sys. Operator*, 187 FERC ¶ 61,154, at P 20 (2024).

based on Bonneville's BAA. Bonneville assessed implementation and participation costs from CAISO, SPP, and internal projections based upon the best available estimates in early 2025.

5.1.2.1. Market Operator Implementation Fee Estimates

EDAM Implementation Fees

CAISO's EDAM transmittal letter to FERC discusses implementation fees.⁷³ CAISO estimates the standard fee to be \$1.2 million for each BAA that elects to join EDAM.⁷⁴ Fees can be larger due to the complexity and size of the joining entity, or if an entity seeks additional market simulation or parallel operations time.⁷⁵ CAISO projects typical implementation to take 18 months for each BAA. The timeline can be extended beyond 18 months to accommodate additional market simulation and parallel operations.

Bonneville is one of the largest transmission providers and BAAs in the Western Interconnection and expects a higher than standard implementation fee and a longer than average implementation timeline. If Bonneville were to elect to join EDAM, CAISO estimates the implementation fee to be between \$2.5 million and \$3 million, and the implementation time frame to be between eighteen and twenty-four months.⁷⁶

Markets+ Implementation Fees

Based on Bonneville's proportional share among all likely funding participants, the estimated share of Phase 2 costs is approximately \$26.8 million.⁷⁷ The implementation costs to join Markets+ are higher than those for EDAM because Markets+ will have its own software separate from SPP's other markets, whereas EDAM is an extension of the current CAISO day-ahead market, and WEIM and is implemented with the same software.

5.1.2.2. Ongoing Market Participation Fee Estimates

EDAM On-Going Fees

CAISO has annual operating fees to run the market. These fees cover the staff, tools, and applications needed for the market. These fees are collected through CAISO's Grid Management Charge (GMC). The GMC is charged to each EDAM transaction. Bonneville requested that CAISO provide a forecast of the annual GMC fees assuming that entities who have made declarations or provided market leanings are included in the EDAM footprint. CAISO projected that Bonneville could anticipate \$29 million annually in GMC.

Markets+ On-Going Fees

Markets+ will also have an annual operating fee. This fee will cover staff, tools and applications needed to run and operate the market. The operating fee will be collected based upon the volume of transactions for each respective market participant. Bonneville contacted SPP to request a forecast of Bonneville's anticipated portion of these annual operating expenses. SPP estimated that Bonneville's expense could be between \$13 and \$15 million annually.

⁷³ CAISO EDAM Filing, Transmittal Letter at 105-07.

⁷⁴ CAISO, Extended Day-Ahead Market Final Proposal at 126 (Dec. 7, 2022), *available at* <https://stakeholdercenter.caiso.com/initiativedocuments/finalproposal-extendedday-aheadmarket.pdf>.

⁷⁵ CAISO EDAM Filing, Transmittal Letter at 105.

⁷⁶ See Bonneville Power Administration, BPA's Public Engagement for Establishing a Policy Direction on Potential Day-Ahead Market (DAM) Participation - Workshop 10 presentation at 18-19 (Jan 29-30, 2025), *available at* <https://www.bpa.gov/-/media/Aep/projects/day-ahead-market/2025/dam-workshop-10-presentation-20250129.pdf>.

⁷⁷ *Sw. Power Pool*, FERC Docket No. ER25-1372, SPP Markets+ Phase 2 Funding Agreement at 24 (Feb. 21, 2025).

Table 9 | Estimated Fees Paid to the Market Operator (\$M)

Estimated Fees for Bonneville	On-going Participation Fee (Paid to MO)*	One-time Implementation Fee (Paid to MO)*
EDAM	~\$29M /year	~\$3M
Markets+	~\$15M /year	~\$26.8M
*BAA value/Bonneville share based on Load/Resource Activity		

Table 9 provides a summary of the on-going participation fees (based on footprints reflecting the current declarations and leanings) and the one-time implementation fees for EDAM and Markets+. While EDAM's implementation fee is quite low at \$3 million, the recurring annual fee is double that of Markets+. The ongoing market participation fees above were provided by each respective market operator in early 2025. These are only preliminary estimates based on the information currently available. These estimates can be subject to change. The fees and cost allocations for each market may evolve as each market operator refines their annual market operating expense.

Bonneville has determined that the higher upfront Markets+ implementation fees are justified by the anticipated market benefits, including the superior design elements (discussed primarily in Section 5.2) and lower ongoing participation fees.

5.1.2.3. Internal Implementation Cost Estimates

Joining a day-ahead market would change the operations and systems for Bonneville across Power and Transmission Services. Bonneville performed an initial estimate of the costs to implement either day-ahead market. This assessment was separate from the E3 PCM cost-benefit analysis, which did not evaluate implementation costs. Any assignment of implementation costs to a particular business line will be done as part of an integrated program review process.

To develop the estimate for the implementation cost of joining a day-ahead market, Bonneville identified projects across the agency that would be required for implementation (e.g., metering, outage management, schedule submission, bid curve development, and settlements). The implementation cost of each project was then estimated based on the complexity in project execution. The cost estimate for each market is further broken into the non-labor and the labor components. The non-labor component reflects initial costs for software and hardware upgrades needed for supporting the technological or operational requirements for joining a day-ahead market, while the labor component reflects the incremental staffing costs. Non-labor costs are provided as a range to reflect the uncertainty around the ongoing EDAM and Markets+ design and development.

Bonneville's estimated implementation costs for EDAM and Markets+ are as follows in Table 10⁷⁸ :

Table 10 | Internal Implementation Costs (\$M)

Market	Non-Labor	Incremental Labor	Total Cost (Non-Labor + Incremental Labor)
EDAM	\$11.6M - \$19.7M	\$18.3M	\$29.9M - \$38M
Markets+	\$26.8M - \$47.3M	\$26.9M	\$53.7M - \$74.2M

⁷⁸ CAISO's and SPP's one-time market implementation fees and annual operating fees are not included.

The estimated implementation cost for EDAM is about half of Markets+, as a large portion of Bonneville’s existing infrastructure built for the WEIM could likely be used in EDAM. SPP has been developing Markets+ consistent with SPP’s existing systems and processes, which are different than CAISO’s and will require system modifications to enable Bonneville’s market participation. Additionally, the higher estimate of the Markets+ implementation cost is also driven by an assumption that Bonneville may choose to switch Bonneville’s Reliability Coordinator (RC) from CAISO RC West to SPP RC Services. While the RC change is included in the estimated costs for transparency, the change is not certain and would depend on future policy development.

5.2. Market Design Considerations

Bonneville has thoroughly evaluated various day-ahead market design elements and participated in the design development process for both EDAM and Markets+. While much of the design is similar between the two markets, there are several differences that Bonneville considers significant in its evaluation. These elements are discussed below.

5.2.1. Governance

Independent market governance continues to be paramount to Bonneville’s Policy direction towards participation in Markets+. Bonneville defines its governance principle for market participation as “the market has a durable, effective, and independent governance structure which provides fair representation to all market participants and stakeholders” and that “decision-making and stakeholder engagement occurs in a transparent and inclusive manner.”⁷⁹ Joining a day-ahead market would represent a significant change to how Bonneville operates. The electric industry is grappling with complex issues, and there will surely be additional difficult issues and circumstances in years to come. While Bonneville can never eliminate all risk, Bonneville believes a governance model tailored to support collaborative, unbiased decisions on current and future issues will mitigate risk inherent to the evolution of the industry. It is not possible to quantify a dollar value for the attributes of independent governance, but substantial value comes through in the decision process for market design and Bonneville’s ability to influence that design. As noted, current examples include, but are not limited to congestion revenue, fast start pricing and GHG accounting.

Through its public discussion of market participation and consideration of market platforms, Bonneville has heard near-consensus agreement that independent governance is a core principle for regional market design.⁸⁰ Bonneville’s evaluation considers the relevant factors associated with governance structures under both Markets+ and EDAM to identify the best governance structure available for Bonneville’s decision regarding day-ahead market participation. While entities may disagree about what level of governance is sufficiently independent, Bonneville wants the decision-making body for a market to be free of disproportionate obligation to the policies of a single state, entity or customer type. Ideally, management and operations of the market would be independent of any single state or participating entity. In the near term, at the management level, the staffing and process for decision development and stakeholder engagement should equitably weigh the policies or priorities of all states, entities, and customer classes. Finally, the market’s design and policies should be equitable in its consideration of the approaches established by all states with participating entities. The following discussion explains the evaluation under each of these factors.

Independence of the decision-making body

In its consideration of EDAM and Markets+, Bonneville evaluated the independence of their respective decision-

⁷⁹ Section 4.1.6 above.

⁸⁰ See, e.g., Letter from Western State Utility Regulators to the Western Interstate Energy Board (July 14, 2023), available at <https://www.westernenergyboard.org/wp-content/uploads/Letter-to-CREPC-WIEB-Regulators-Call-for-West-Wide-Market-Solution-7-14-23-1.pdf>.

making bodies.

Today, governance for EDAM is entrusted to the CAISO Board of Governors. The Board has delegated certain authority to the Western Energy Markets (WEM) Governing Body, subject to the Board's oversight, in a model referred to as Joint Authority.⁸¹ The CAISO Board of Governors is appointed by the Governor of California with the consent of the California State Senate. Board members oversee CAISO in both its role as the market operator and largest BAA in the market. Members of the WEM Governing Body are nominated from stakeholder sectors and approved by current members of the Governing Body. The Governing Body acts on recommendations developed under the CAISO stakeholder process, which is largely CAISO staff driven. CAISO utilizes working groups to develop the initial stages of policy initiatives then proposals are developed by staff with open comment opportunities for all stakeholders.

The Governor of California's selection of the CAISO Board of Governors risks undue influence of a single state over EDAM. In addition, California law establishing authority for the CAISO Board of Governors requires it to act in the interests of the people of California.⁸² While these governance elements were reasonable for the original CAISO market that only operated within California, they are significant flaws in the governance of a regional market that includes participants in other states. These flaws require mitigation that is currently only proposed.

As addressed in Appendix B, a number of regional entities have acted in pursuit of this objective through Pathways,⁸³ which will be discussed in more detail. Pathways has continued development of proposals for a new entity with an independent governance structure that is capable of overseeing an expansive suite of West-wide wholesale electricity markets and related functions. In 2024, the CAISO Board of Governors and the WEM Governing Body jointly approved additional governance changes that were recommended from Step 1 of Pathways. These changes placed the sections of the CAISO Tariff for WEIM and EDAM under the primary authority of the independent WEM Governing Body. WEM Governing Body decisions will be reviewed by the CAISO Board of Governors on a consent agenda. If the Board disagrees with the Governing Body's decision or vice versa, CAISO will prepare and submit dual filings to FERC on behalf of each body. The CAISO Board of Governors may exercise sole authority for FERC filings in exigent circumstances. Critically, the day-to-day management of policy development and market operations remains with CAISO management who ultimately report to the CAISO Board of Governors. Additionally, the Board's considerations as a BA have the potential to influence its decisions as the market operator.

In contrast, Markets+ will be governed by the Markets+ Independent Panel (MIP).⁸⁴ MIP members must be independent of market participants. They are selected through a nomination process of the Markets+ Governance and Nomination Committee and confirmed by the Markets+ Executive Committee. One independent member of the SPP Board of Directors serves on the MIP. The SPP Board of Directors retains authority for specific financial oversight of Markets+. The independent board acts on recommendations developed through a transparent process involving all market participants and stakeholders. The participants and stakeholders collaborate in working groups that have proven effective to build consensus and, where consensus is elusive, to frame the different perspectives for the independent board's consideration in its decisions.

Markets+ decision-making will be under the authority of the MIP whose members, save one representative of the SPP Board, are selected by the Markets+ participants. Additionally, Markets+ is separate from the SPP RTO, so its only focus is on being a market operator. From this comparison, Bonneville finds that the independence of the

⁸¹ See CAISO, Governance (2025), available at <https://www.westerneim.com/Pages/Governance/default.aspx>.

⁸² Cal. Pub. Utils. Code § 345.5 (2025).

⁸³ See Western Interstate Energy Board, West-Wide Governance Pathways Initiative (2025), available at <https://www.westernenergyboard.org/wwgpi/>.

⁸⁴ SPP Markets+ Tariff, Attach. O (Markets+ Governance) § 4.2 (Markets+ Independent Panel). Pending initiation of operations as Markets+, this independent board role is exercised by the Interim Market Independent Panel (IMIP) of three members of the SPP Board. References to the ongoing role of the Markets+ independent governing board will be to the MIP.

Markets+ decision-making body is superior to that of the EDAM and is more likely to result in decisions that create a fair and equitable market that allows Bonneville to meet its load service, power marketing, and transmission obligations.

Decision development and stakeholder engagement

In Bonneville's experience, a market's structure for both stakeholder engagement and decision development are critical to ensuring fair and equitable decision outcomes. Bonneville places great weight on the supporting structure for market decision development through market operator staff and the roles of participants and stakeholders in policy development. This structure is critical to ensure that Bonneville's interests are heard and adequately addressed in the decision process. The difference is not theoretical; Bonneville has been an active participant in both EDAM and Markets+ stakeholder processes and has experienced the difference in terms of decision-making for agenda priorities, collaborative process, and consensus decisions.

Bonneville has observed that the Markets+ structure has a proven track record of effectiveness. Notably, the structure delivered the complete tariff design on an abbreviated schedule through 2023. The structure involved working groups and task forces of market participants and stakeholders who conducted their discussions in publicly noticed and accessible meetings. The structure uses "indicative voting" to document support and opposition from participating stakeholders individually and by sectors. The use of indicative voting promoted collaboration among participants and built confidence in the outcomes. A prime example of the success of the Markets+ governance structure is the development of a mechanism for GHG accounting that meets customer compliance obligations for multiple states and pricing approaches while not adversely affecting states without those obligations.

Bonneville proposed and obtained consideration of its statutory and contractual obligations through the Markets+ process. The working group processes are publicly accessible and consider perspectives from utilities, states, and independent organizations. Stakeholders themselves can set the agenda for issues to be considered by the Interim MIP (IMIP). SPP staff provide appropriate facilitation and technical support roles while respecting the decision-making roles of market participants. The Markets+ Executive Committee (MPEC) ultimately votes on decisions to be brought before the MIP, providing a final opportunity for input from the sectors. Decisions reflected negotiation and compromise, with the IMIP returning issues to the MPEC when insufficient consensus had been reached.

The Markets+ governance structure relies on the time and abilities of market participants and stakeholders to develop market design proposals and deliberate on recommendations. Bonneville acknowledges concerns about that level of commitment. From Bonneville's perspective, this time is well invested for the value of collaboration among participants, shared understanding of the issues and tradeoffs involved, and for durable outcomes. The experience to date has been demanding, to be certain. However, it has yielded unparalleled engagement in the complex challenge of establishing a market. As the market moves into implementation, the cadence of participant work should be more manageable and provide opportunities for entities to combine their efforts.

Bonneville has not experienced the same depth of balanced stakeholder consideration in the staff-driven CAISO engagement model. Bonneville acknowledges the knowledgeability of CAISO staff and CAISO's efforts to develop a more participatory stakeholder engagement process. Bonneville appreciates and respects the professionalism and expertise that CAISO staff routinely display in their stakeholder process. This process, however, could be enhanced through increased stakeholder leadership in policy and implementation development, evaluation, and decision processes. The CAISO governance model also continues to present challenges in resolving contentious regional issues. CAISO must navigate competing priorities for staff and management time on regional issues versus the demands for attention to its own BAA and participating transmission owners.

Bonneville concludes that the Markets+ decision development and stakeholder engagement process is the best approach to ensure a fair and equitable market across multiple states and fair consideration of Bonneville's objectives and obligations.

Reasonable harmonization of state policies

The influence of an individual state in market design can manifest in the obligation of the market to incorporate that state's regulatory or policy design as predetermined conditions. Bonneville, especially from its role as serving utility customers in seven states, seeks a governance model that fosters harmonizing differing state policies.

The structure of the Markets+ policy process supports treatment of different state policies on an equal basis. The policy development process invites market participants to bring their state compliance obligations to the market design and includes the active participation of state representatives. Bonneville observes that this structure has allowed consideration of different state policy designs to arrive at a high degree of consensus on designs that serve the goals of multiple states and the utilities that serve them.

By contrast, CAISO market design rests on a foundation of California state policies. In the design of a regional wholesale market, this approach carries forward to a choice that either California's policy design, for example in GHG accounting, must be accepted as the market standard, or that the market must develop and incorporate alternative designs for those participants outside California.

Bonneville determines that the equivalent consideration of state policies by the Markets+ governance design is superior to that of the EDAM. Currently, there are two FERC approved day-ahead market tariff options available to Bonneville but one—Markets+—is superior with respect to stakeholder engagement, decision-making, and overall market governance.

5.2.1.1. Impact of Pathways on Bonneville's -Day-Ahead Markets Decision

Bonneville has assessed the progress made by Pathways in evaluating its day-ahead market alternatives. Through the Pathways engagement, Bonneville has supported the option for creation of an independent entity with independent administration and operation. While Pathways has made progress in advancing the governance of the WEIM and EDAM, the initial structure proposed in the Step 2 final proposal does not meet Bonneville's standards for independent governance as discussed in detail in Appendix B. The proposed approach is also dependent on legislation successfully passing in California to enable the Regional Organization (RO) structure as proposed, and allowing expansion to greater independence as described in the Step 2 proposal. California Senate Bill 540 seeks to enable the Pathways Step 2 recommendation. The legislation would authorize the CAISO and California investor-owned utilities to participate in voluntary energy markets governed by an independent regional organization. Proposed legislation responds to a delicate balance between the interests of parties outside of California, including Bonneville, that the independent regional organization be wholly separated from undue influence of California state government; and the interests of parties in California that the regional organization support California energy and environmental policies. To achieve this balance, the current legislation seeks to reassure California that there are adequate safeguards for respecting California policies through providing for rights of withdrawal as ordered by the California Public Utilities Commission (CPUC). The proposed legislation provides that the CPUC may order California IOUs to withdraw in response to market rules or operations that it deems "detrimental to California consumers or California procurement, environmental, reliability, or other public interest policies." While presented as a "savings" provisions representing current CPUC authority, this scope of authority is made explicit by the proposed legislation. In continuing legislative committee discussions, the bill author and legislators have discussed adding more "guardrails" to ensure market respect for a broad list of California policies and adding requirements for additional legislative review of the RO structure and functions. In emphasizing these authorities as a means of reassuring California policy leaders, it causes reasonable and substantial concern for entities outside of California. Entities outside of California, including Bonneville, will be in a difficult negotiating position within the regional organization governance structure when any proposed rule or business practices can be referred to the CPUC or Legislature for a determination that the proposal will be "detrimental" to a broad and general set of policies. The legislation does leave available improvements in the stakeholder process and market design process to make it more equitable for parties inside and outside of California. Nevertheless, Bonneville is concerned that the legislation as drafted may not meet Bonneville's governance requirement. At the time of this Policy direction, uncertainty remains regarding whether SB 540 will ultimately be passed and, if so, in what form.

5.2.2. Resource Adequacy and Resource Sufficiency

As discussed in section 4.1.3, a primary aspect of reliability impacted by market design is resource sufficiency and by extension, RA. RA generally refers to long-term planning and procurement of resources to serve expected peak or critical load in a year or season. Resource sufficiency generally refers to procurement of enough resources to serve expected load in the short term (e.g., moving into the week/day/hour). In considering generation and transmission, RA aims to have enough physical resources (e.g., long term expected generation output, new generation or transmission construction) to serve a forecasted peak load well into the future (often many months or years), while resource sufficiency considers the current operational landscape (e.g., outages or derates, up-to-date variable generation and load forecasts, etc.). The two concepts work in concert and are both vital to minimizing scarcity, emergency, or loss-of-load events. The market operator does not take on the role of LRE in either day-ahead market option.⁸⁵ All day-ahead market participants are still responsible for their adequacy and sufficiency, and thus obligated to enter the day-ahead market timeframe with a resource portfolio (including power purchases) that can meet their expected load.

Markets+ contains both an RA and resource sufficiency requirement. As a prerequisite to joining Markets+, entities that are LREs must participate in WRAP.⁸⁶ WRAP is a regional RA program that increases transparency into the resources and transmission needed to reliably supply power to meet a participant's existing and future load demands. Participation in WRAP requires consistent planning from all participants (which is measured using common RA metrics applied consistently to all participants), to help prevent any entity from leaning on the power supplies of others. Current WRAP participants include most utilities within the Western Interconnection outside the state of California.⁸⁷ For long- and short-term planning, the WRAP Forward Showing program requires entities to demonstrate that they have the available generation capacity needed to meet its forecasted peak P50 obligations plus an established planning reserve margin, and 75% of the transmission (as firm transmission) needed to bring generation to load.⁸⁸ While Markets+ participation is not required to be a WRAP member, Markets+ is the only day-ahead market choice in the West that requires participants to be in a common RA program, in this case, WRAP.

WRAP feeds into Markets+ via the market's day-ahead and real-time Must Offer Obligations. The Must Offer Obligations require all entities to bring at least the amount of generation needed to meet their forecasted load. If an entity fails to meet its Must Offer Obligation, that entity is financially penalized to discourage failures in the future, but physical market transfers and the optimization of the market footprint are not impacted. This simplified approach is supported by the Markets+ common RA metrics provided by universal WRAP participation because market participants are not only checked for day ahead and real-time sufficiency, but are also assessed for RA much farther out than real time. The inclusion of WRAP and the potential charges for failure to be resource adequate disincentivizes utilities who do not have adequate resources from leaning on other market participants in order to serve load in a manner that is stronger than the EDAM design, which, as explained below, relies only on penalties in the operational timeframe.

The EDAM design does not propose a uniform RA metric nor require EDAM entities to participate in an RA program. EDAM does leverage a Resource Sufficiency Evaluation (RSE) to ensure its footprint is adequate heading into the day-ahead and real time operating periods. EDAM's design leverages the WEIM design which calls for the limiting of an entity's BAA-BAA market transfers for entities that ultimately fail the real time RSE unless entities elect to accept

⁸⁵ A Load Responsible Entity (LRE) is an entity directly responsible for ensuring an electrical load is served.

⁸⁶ SPP Markets+ Tariff, Attach. A § 5.1.1; *id.* Appendix 3 (Attestation Regarding RA and Participation in WRAP).

⁸⁷ Western Power Pool, WRAP Participant Map (last mod. Dec. 30, 2024), available at <https://www.westernpowerpool.org/news/wrap-area-map>.

⁸⁸ Western Power Pool, WRAP Tariff § 16.3 (FS Transmission Requirement), available at https://www.westernpowerpool.org/private-media/documents/WRAP_Tariff_Effective_1.27.25.pdf ("The FS Transmission Requirement must be met with NERC Priority 6 or NERC Priority 7 firm point-to-point transmission service or network integration transmission service, from such Participant's Qualifying Resource(s) or from the delivery points for the resources identified for its Net Contract QCC or for its RA Transfer to such Participant's load.").

energy transfers through Assistance Energy Transfers, which include an associated penalty charge.⁸⁹

The Markets+ Must Offer Obligation and the EDAM RSE serve a similar purpose, which is to evaluate whether each entity has procured enough resources to support its anticipated demand for the coming day, but the Markets+ integration of WRAP helps ensure equal and prudent planning and resource acquisition in the longer term. By leveraging the WRAP Forward Showing Program through its day-ahead and real-time Must Offer Obligations, Markets+ standardizes, simplifies, and solidifies each market participant's requirements to bring sufficient resources to the market to serve its loads. The more simplified resource sufficiency tests that Markets+ employs in the day-ahead and real-time also have the potential to provide benefits to Bonneville and other Markets+ participants. WRAP participation and the Markets+ Must Offer Obligations ensure sufficiency in a manner that sends strong financial signals that disincentivize future failure to bring sufficient capacity to the market and compensate those who make up any shortage, while still allowing all entities, and the market as a whole, to maintain a reliable, optimized footprint.⁹⁰

While some California utilities are subject to RA requirements under the CPUC jurisdiction, these metrics may be different than those used in WRAP. Further, EDAM participants outside of California may be participants in WRAP, but they are not required by the EDAM market to participate in any RA program. EDAM's lack of common RA metrics makes it difficult to assess whether the footprint as a whole will be resource adequate in the planning horizon. While the EDAM RSEs are intended to prevent market participants from leaning on other market participants by failing to provide sufficient resources to meet their own loads absent market optimization, there are limited options in the day-ahead timeframe for addressing footprint wide sufficiency issues. A lack of a common RA program leaves the task of disincentivizing leaning solely to the EDAM RSE. Limiting transfers for entities that fail the real time RSE is suboptimal for all market participants, and the AET rate alone does not provide as robust an incentive for participants to maintain resource adequacy or resource sufficiency as the design of Markets+. ⁹¹ As long as EDAM entities find it more economical or convenient to pay the AET, they can lean on other EDAM entities as a substitute for effective long-term planning to meet their load obligations. The combination of both WRAP charges and the Must Offer Obligation makes such a determination less likely in Markets+.

As concerns continue to grow about RA in the Western Interconnection,⁹² the Markets+ design is objectively superior to EDAM because it combines a common long-term RA metric with short-term resource sufficiency obligations, ensuring adequate supply, reliability, and fair compensation. Therefore, Bonneville views Markets+ as the superior day-ahead market choice for supporting regional RA.

5.2.3. Price Formation and Market Power Mitigation

Appropriate price formation ensures that market rules provide appropriate price signals, which compensate resources at prices that reflect both the value the resources provide to the market and the operational conditions that drive the need to procure certain energy or capacity products. Price formation should also ensure that resources respond appropriately and accurately to dispatch instructions from the market. Key aspects of price formation⁹³ issues can include: uplift payments (including bid cost recovery which can undermine actionable price signals), offer caps and offer mitigation usage, scarcity pricing, fast start pricing, and operator actions (and any associated impacts, or lack thereof, on pricing).

⁸⁹ CAISO, Extended day-ahead market resource sufficiency evaluation discussion at 8 (Oct. 21, 2022), *available at* https://www.caiso.com/Documents/ExtendedDay-AheadMarketResourceSufficiencyEvaluation-Presentation-Oct21_2022.pdf. CAISO, WEIM Resource Sufficiency Evaluation Enhancements – Phase 2 (November 7, 2022), *available at* https://stakeholdercenter.caiso.com/InitiativeDocuments/Presentation-ResourceSufficiencyEvaluationPhase2-Nov7_2022.pdf.

⁹⁰ SPP Markets+ Tariff, Attach. A §§ 5.1.1(C), 5.1.2(C).

⁹¹ CAISO, Extended day-ahead market resource sufficiency evaluation discussion at 8.

⁹² WECC, 2024 State of the Interconnection (Sept. 2024), *available at* <https://feature.wecc.org/soti/index.html>.

⁹³ For more information see FERC, Energy Price Formation (June 17, 2020), *available at* <https://www.ferc.gov/industries-data/electric/electric-power-markets/energy-price-formation>.

Related to price formation and necessary for a well-functioning electricity market, is the monitoring and mitigation of market power. The exercise of market power is when one or more entities reduce output below competitive levels so as to raise market-clearing prices.⁹⁴ Due to the nature of the deregulated electricity industry, with several large suppliers, who are regionally concentrated and loads with limited ability to exercise price sensitive demand, there is a possibility for the exercise of market power by certain entities. While organized markets are structured to encourage competitive and efficient outcomes through their formation, structural or behavioral issues may allow exercises of market power, which can be mitigated by design. Market power mitigation tests and rules, when effectively implemented, ensure that resources can bid their marginal costs, but are not able to exercise market power. Both market operators and market monitoring departments are committed to monitoring for and mitigating the exercise of market power, though they have different methodologies for assessing the market.

In EDAM, the Market Power Mitigation (MPM) assessment is an extension of the existing WEIM methodology, which looks to address structural market power in participating BAAs. BAA-level MPM uses a dynamic competitive path assessment to evaluate whether the available generation within the participating BAA can competitively meet its own demand without additional transfer imports. If the dynamic competitive path assessment conditions are deemed non-competitive, then all participating resources in the affected BAA are adjusted to the competitive locational marginal price or a lower value of their submitted bid or applicable Default Energy Bid (DEB).

Under the pivotal supplier assessment for MPM, large entities flowing on constrained paths are more likely to be considered a pivotal supplier and face price mitigation measures, by the nature of their structural location, leading to potential over-mitigation. Given the geographical structure of western BAAs, the mitigation assessment based on the pivotal supplier is determined on the participant's potential ability to exercise market power, rather than on the participant's observed behavior. Bonneville appreciates that CAISO is reviewing this aspect of the market design in its Price Formation Enhancements initiative.

In contrast, the Markets+ design leverages the conduct and impact framework for MPM which is used in other organized markets.⁹⁵ The conduct test evaluates whether a resource offer is significantly higher than the reference cost of energy, and the impact test determines whether that offer would significantly impact the market prices. If suppliers have been found to fail both conduct and impact tests, then mitigation measures can be applied. Under this framework, resource offers are actively assessed and a negative outcome to the market must occur in order to be considered an exercise of market power. Basing mitigation assessments on the perceived potential to exert market power, as EDAM does, particularly during times of scarcity, creates misaligned incentives and market signals which can prevent appropriate market outcomes. The Markets+ conduct and impact approach is more effective because it mitigates based on the exercise of observed market power, not the potential for market power, thus minimizing over mitigation.

In addition to the assessment for MPM, a key aspect of the market design is to ensure that the reference price calculation, the offer price used when a resource is mitigated, is appropriate. The methodology to determine the reference price for a mitigated offer curve will vary by resource type. For resources such as storage hydro, a key aspect is the opportunity costs associated with future generating periods. For storage hydro, the Markets+ and EDAM are very similar, as the Markets+ design was built upon the approach utilized in WEIM. Bonneville's internal opportunity cost estimation, a component of bid formulation, is dynamic and based on non-public information, making independent verification impossible, though both markets attempt to approximate Bonneville's

⁹⁴ For more information see Scott Harvey and William Hogan, Market Power and Withholding (Dec. 20, 2001), *available at* https://scholar.harvard.edu/files/whogan/files/market_power_withholding_harvey-hogan_12-20-01.pdf.

⁹⁵ See SPP Markets+ Tariff, Attach. B (Market Power Mitigation Plan) & Attach. C (Market Monitoring Plan); *see also* SPP Markets+ Protocols § 11 (Market Monitoring and Mitigation), *available at* <https://www.spp.org/Documents/73199/MarketsPlus%20Protocols%20-%20Combined%20-%20MPEC%20Approved%20as%20of%2020250131.pdf>.

cost for mitigation purposes. Imperfect cost verification (conduct verification) further reinforces the important role of an impact test to reduce inappropriate over-mitigation.

In EDAM, CAISO employs the DEB model for hydroelectric resources. The DEB uses a formula to estimate the opportunity cost of hydro, focused on three main pricing components: a gas-price floor, short-term energy prices, and a long-term geographic floor. This approach specifically tailors the DEB of a participating resource to its geographic location. Markets+ stakeholders worked with SPP's Market Monitoring Unit to develop the Seasonal Hydroelectric Offer Curve (SHOC) framework. The SHOC is very similar to the DEB but also accounts for a hydro project or aggregation of projects' seasonal storage horizon as part of the opportunity cost calculation.⁹⁶ Both designs do their best to account for the flexibility of the system, allowing participants to preserve the value of hydro for future months when appropriate for their resource(s), helping other market participants benefit from the flexible nature of these resources. Bonneville prefers the Markets+ SHOC approach because it distinguishes between hydro resources with and without significant storage availability.

CAISO has undertaken stakeholder initiatives, such as the Day-Ahead Market Enhancements (DAME) and Price Formation Enhancements, to review and address changes to products and prices within its market. During its DAME⁹⁷ effort, CAISO created the Imbalance Reserve Product, which recognized the need to procure additional flexible products that can be economically awarded to help provide additional capacity and reduce out-of-market actions by the market operator. The CAISO/EDAM footprint had a demonstrated need for this product due to the uncertainty swings in the load-resource balance caused by the variable renewable resource mix within the footprint and the need for dispatchable resources that are deliverable and can ramp between fifteen-minute intervals⁹⁸. While Bonneville was initially very supportive of this product, the final product design changed significantly in the final stages of the stakeholder process, at which point Bonneville identified a number of significant areas of concern, as did other stakeholders⁹⁹. While Markets+ does not include a comparable product, WRAP includes financial incentives to ensure equitable procurement of capacity to prevent leaning on the capacity of others, as well as compensation for holdback and energy deployment. Bonneville accepted the position that developing a similar product in Markets+ without a demonstrated need could impose additional and unnecessary costs to load service and agreed to move the topic to the Markets+ "parking lot" for consideration after go-live. Bonneville will monitor its participation in Markets+ and consider whether it feels a similar product would be necessary and/or beneficial to the Markets+ design. Bonneville is confident that the Markets+ stakeholder process will address any concerns that arise.

In the Price Formation Enhancements initiative,¹⁰⁰ scarcity pricing and fast-start pricing are critical elements because they can ensure resources are appropriately incentivized and compensated for the attributes they bring to a market dispatch, while reducing the need for out-of-market actions. In addition to ensuring accurate prices in the short term, price formation can help send better price signals for developing supply to meet future demand. Transparent and equitable price formation is an important step toward increasing market efficiency through increased competition, potentially ensuring supplier cost recovery while reducing the cost load pays.

CAISO has mechanisms for implementing a level of scarcity pricing when the system is low on reserves and

⁹⁶ See SPP Markets+ Tariff, Attach. B (Market Power Mitigation Plan) & Attach. C (Market Monitoring Plan); *see also* Markets+ Protocols § 11.

⁹⁷ See the CAISO Day-Ahead Market Enhancements Initiative page for more details on these efforts and for Bonneville-submitted comments, *available at* <https://stakeholdercenter.caiso.com/StakeholderInitiatives/Day-ahead-market-enhancements>.

⁹⁸ *Id.*; *see also* CAISO, Day-Ahead Market Enhancements Stakeholder Technical Workshop presentation at 6 (June 20, 2019), *available for download at* <https://stakeholdercenter.caiso.com/StakeholderInitiatives/Day-ahead-market-enhancements>.

⁹⁹ See CAISO, Day-Ahead Markets Enhancements Initiative (comments submitted by Western Power Trading Forum, Vistra, The Energy Authority, and Powerex) *available at* <https://stakeholdercenter.caiso.com/StakeholderInitiatives/Day-ahead-market-enhancements>.

¹⁰⁰ *See id.*

network modeling needs to solve for tighter bid-supply conditions, but it does not currently have a design that includes compensation for fast-start pricing. Fast start pricing allows a generator's commitment costs, in addition to marginal fuel costs, to be considered in economic bid evaluation and directly captured in LMPs paid to all resources. CAISO is currently reviewing these topics as part of its Price Formation Enhancements initiative, in which Bonneville is actively engaged, although many stakeholders continue to oppose the adoption of fast start pricing. The absence of fast start pricing in CAISO reduces costs for California load by reducing fair and transparent compensation for generation in both California and throughout the West, including Bonneville's generation. In contrast, Markets+ incorporates fast-start as well as scarcity pricing into its day-ahead market design, which Bonneville believes helps to ensure accurate, fair compensation for all suppliers of flexible and reliable generation.

Bonneville's position on price formation and market power mitigation assessments has not changed from the April staff recommendation.¹⁰¹ These are cornerstones of organized markets. Markets+ design elements ensure that resources can efficiently respond to market signals and be appropriately compensated, while avoiding over mitigation and ensuring transparent market pricing. Therefore, Markets+ design is more aligned with Bonneville's perspective regarding MPM and price formation, which can help improve outcomes for both resources and loads.

5.2.4. Congestion Modeling and Congestion Rent

Generally, the overall transmission design between EDAM and Markets+ is similar. Both day-ahead market frameworks rely upon transmission made available by market participants, TSPs, and transmission customers to facilitate the transfer of energy across the market footprint.¹⁰² Market participants and participating TSPs in EDAM and Markets+ must make their transmission available for market use as a condition of participation, unless specifically opted out according to the respective market's rules. The CAISO EDAM Tariff allows participating entities to let transmission customers designate any of the transmission rights they hold as non-participating. The EDAM design intends for the EDAM Entity to make the ultimate decision to enable this market feature in its BAA.¹⁰³ The SPP Markets+ Tariff includes the opt-out of transmission from the market as part of the market design and has already established a communication process to opt-out transmission. In addition, both markets are designed to recognize market participants' existing transmission rights that can still be exercised in the day-ahead and real-time horizons. This is further explained in Section 6.8.

Physical Congestion Modeling

Ultimately, both EDAM and Markets+ will model constraints and manage transmission similarly. From a BAA perspective, each market will have to ensure that each participating and adjacent BAA can continue to calculate its

¹⁰¹ Bonneville Power Administration, Staff Recommendation on Day-Ahead Market Participation (Apr. 2024), available at <https://www.bpa.gov/-/media/Aep/projects/day-ahead-market/2024/02-day-ahead-market-attachment-1-staff-recommendation.pdf>.

¹⁰² SPP Markets+ Tariff, Attach. D (Markets+ Transmission) § 1.0 (General); CAISO EDAM Filing, Tariff Appendix B.33 (EDAM Transmission Service Provider Agreement (EDAMTSPA)).

¹⁰³ The CAISO EDAM tariff provides:

Transmission Not Available in the Day-Ahead Market. If the CAISO is informed through the prospective EDAM Entity implementation process or by the EDAM Entity Scheduling Coordinator for the EDAM Transmission Service Provider that accommodation of incremental intra-day schedules in the Real-Time Market should be unavailable in the Day-Ahead Market according to the EDAM Transmission Service Provider tariff, the CAISO will accept a notification from the EDAM Entity Scheduling Coordinator associated with the EDAM Transmission Service Provider and will adjust Day-Ahead Market availability of the impacted transmission elements and the associated transmission service rights.

Cal. Indep. Sys. Operator Corp., FERC Docket No. ER23-2686, Transmittal Letter, Attach. A-2, Tariff § 33.18.3.3 (Aug. 23, 2023).

Net Scheduled Interchange (NSI), Net Actual Interchange, manage area control error (ACE)¹⁰⁴ in real-time, and perform After the Fact (ATF) energy accounting. Further, capacity or energy transfers from each BAA (EDAM and Markets+) must accurately account for Bonneville transmission rights that were used to facilitate the transfers. At times, these BAA-to-BAA rights and transfer accounting models in each market may end up being constrained and produce congestion revenue which will need to be allocated. Further, each market will also be able to model physical constraints (e.g., flowgates, paths, or lines). When the physical limit (or allocation of a physical limit) is reached in either the day-ahead or real-time, each market will attempt to honor the limit and potentially produce congestion revenue. Any congestion revenue would be allocated under the market tariff or under the participating BA's tariff in the case of EDAM, as described below.

Congestion Rent Allocation

Congestion rents¹⁰⁵ are payments to participants that occur within a market when the types of constraints described above become limiting (i.e., when congestion occurs). When congestion occurs at a constraint, the least-cost energy cannot be awarded to be delivered to all loads while respecting the constraint limits. The price to serve an incremental MW of load on either side of the constraint is different, resulting in different costs to serve demand in different locations.

To illustrate, a hypothetical generator clears at \$25/MW and some portion of its output is serving load across a constraint. Due to congestion, it cannot send an incremental MW of energy across the congested element. Another resource offers \$35/MW. The load will pay \$35/MW rather than \$25/MW because its incremental MWs are served by the other resource offering \$35/MW. In this scenario, the market operator will have received more money than it distributed due to the congestion that caused price separation between LMPs.¹⁰⁶ The market operator must then allocate these congestion revenues in some manner to ensure that it remains revenue neutral. Methodologies for how a market allocates this congestion revenue vary, but generally the aim is to return it to the loads and to the transmission rights holders.

In most RTOs and ISOs, this allocation is effectuated by the conversion of physical OATT rights to Congestion Revenue Rights (CRRs) or similar path-specific financial rights, which can also be procured through auctions. However, neither Markets+ nor EDAM will rely on these financial instruments. Congestion rent is instead dictated by the respective market design and as applicable, the participating TSP OATT. The congestion rent designs and allocation methodologies for the proposed day-ahead markets are quite different.

EDAM breaks all congestion rents into two categories: congestion revenue and transfer revenue. In EDAM, congestion revenues are allocated to the BA where the binding constraint is modeled.¹⁰⁷ Transfer revenue is

¹⁰⁴ Area Control Error (ACE) is a real-time calculation performed by every BAA's Automatic Generation Control (AGC) system that indicates when something has changed and the BAA or interconnection is not balanced, such as: BAA load deviated from forecast, generator deviated from schedule, interchange deviated from schedule, or interconnection frequency deviated from schedule. ACE is measured in megawatts (MW).

¹⁰⁵ Congestion management includes all operational actions taken by grid/transmission operators to **proactively** and efficiently manage congestion, maintain the smooth flow of energy, and minimize the need to take operator actions in real-time. One aspect of congestion management is ensuring that a Market Operator honor the operational limits provided by TSPs and TOPs and that these operational limits are reflected in the market dispatch. Respecting these operational limits can result in price separation between loads, which results in congestion revenue or rent. Congestion revenue or rent is the money collected by the market operator due to the operational limitations that result in price separation between load and generation. Congestion rent is the term used in Markets+ and how we will refer to this topic generally. EDAM specifically differentiates between congestion revenue and transfer revenue as two components of the allocation of these congestion rents.

¹⁰⁶ To see a more detailed example of congestion, please see Bonneville Power Administration, BPA's Public Engagement for Establishing a Policy Direction on Potential Day Ahead Market (DAM) Participation - Workshop 7 presentation (June 3, 2024), available at <https://www.bpa.gov/-/media/Aep/projects/day-ahead-market/2024/dam-workshop-7-presentation-060324.pdf>.

¹⁰⁷ See CAISO EDAM Filing, Tariff § 33.11.1.2 (Congestion Revenue).

collected when the net EDAM Transfer scheduling limit is reached in the day-ahead market, representing price separation between neighboring BAs in EDAM.¹⁰⁸ The transfer revenue is allocated equally between the two BAs, unless there is an alternative commercial arrangement.¹⁰⁹ An EDAM transfer rights holder that makes capacity available to CAISO is eligible to receive transfer revenue and congestion revenue settlements through the Scheduling Coordinator.¹¹⁰ The allocation of congestion revenue and transfer revenue collected by the EDAM entity will be suballocated according to that EDAM BAA's OATT. The suballocation of congestion rents is thus subject to the individual rules of the transmission service provider's Tariff. This can present undue complexity for customers by producing a wide set of outcomes depending on the tariff or tariffs to which a customer is subject.

A fundamental challenge Bonneville sees with the EDAM approach to congestion rent is the allocation being based on BAs, rather than a footprint-wide allocation which focuses on rights attributable to key constraints. A transaction occurring inside of EDAM, even a scheduled delivery that exists entirely within one BA, could be exposed to congestion that occurs elsewhere within the EDAM footprint. Per the EDAM design, the revenues of this transaction would be solely distributed to the BA where the congestion is binding. Due to the nature of physical flows, this could be a frequent occurrence. Without the means to recover revenue from congestion that may have occurred in a neighboring BAA, entities are presented with the potential to be exposed to congestion charges without the means to adequately hedge or recover revenue from the costs incurred by load. When the congestion revenue occurs within the BAA, there is no guarantee that the BA's OATT will allocate congestion by constraint within their BAA, presenting additional risk that loads will be exposed to costs and unable to recover offsetting congestion revenue.

Issues with the EDAM design and concerns regarding parallel flows became apparent when PacifiCorp filed its Tariff revisions with FERC to enable its participation in EDAM.¹¹¹ Protesters raised concerns that the EDAM design did not allow for "a sufficient congestion hedge to transmission customers exercising their transmission rights."¹¹² In response to these protests, CAISO initiated an expedited stakeholder initiative to address these concerns. CAISO's proposal is "to allocate parallel flow congestion revenues to the EDAM balancing area where these revenues accrue associated with the exercise of long-term firm and monthly firm Point-to-Point and Network Integration Transmission Service rights based on submitted day-ahead balanced source and sink self-schedules."¹¹³ While this proposed change presents a better hedge than the current design, Bonneville's concerns regarding the BAA sub-allocation design and the lack of direct hedging by constraint remain. In addition, proposed tariff revisions of entities pursuing participation in EDAM require self-scheduling in order to receive congestion rent.¹¹⁴ Incentivizing self-scheduling significantly reduces economic participation in the market and limits optimization benefits.

Markets+ takes a very different approach to the allocation of congestion rents. It does not differentiate between congestion occurring within BAAs or between BAAs, but rather it evaluates allocations across the entire footprint, specifically the rights associated with individual constraints. The allocation of eligible rights by physical constraint across the entire footprint, rather than allocating by BAA, mitigates the concerns with the EDAM design highlighted above. In Markets+, congestion rents associated with physical constraints are allocated directly and proportionally to the transmission rights holders of firm and conditional firm PTP transmission service, network integration

¹⁰⁸ See *id.* § 33.11.1.1 (Energy Transfer Revenue). This language allows for either a 50/50 allocation or another pre-existing commercial arrangement.

¹⁰⁹ See *id.*

¹¹⁰ See *id.* § 33.18.4 (CAISO Transmission at EDAM Interties).

¹¹¹ *PacifiCorp*, FERC Docket No. ER-25-951-000.

¹¹² *Draft Final Proposal: EDAM Congestion Revenue Allocation* at 3 (April 16, 2025) (available at: <https://stakeholdercenter.caiso.com/InitiativeDocuments/Draft-Final-Proposal-EDAM-Congestion-Revenue-Allocation-April-16-2025.pdf>).

¹¹³ *Id.* (parentheticals omitted).

¹¹⁴ *Portland Gen. Elec.*, FERC Docket No. ER-25-1868-000, Transmittal Letter at 17 (April 3, 2025); *PacifiCorp*, FERC Docket No. ER-25-951-000, Transmittal Letter at 18-19 (Jan. 16, 2025).

transmission service, and legacy transmission service of monthly or longer service increments whose rights are associated with that physical path, who have not opted these rights out of Markets+. ¹¹⁵

Under the Markets+ design, PTP eligibility will be based on the eligible transmission service request (TSR), while NITS eligibility is tied to an allocation cap based on the customers' monthly peak load and the allocation across paths is based on the designated network resources offered to serve their loads. ¹¹⁶ However, if NITS customers use secondary NITS service, the Markets+ design does not include secondary service in the direct congestion rent allocation. In these cases, there may be congestion revenue, but SPP will not allocate it directly to the Market Participant. SPP will allocate any undistributed congestion revenue to the TSP, and the TSP will allocate those revenues according to its tariff. ¹¹⁷ In addition, the congestion revenue design will be monitored by the Markets+ stakeholders, with an emphasis on ensuring equity between customer types, and evaluated for potential changes in the future that may result in updates to the Markets+ design if appropriate ¹¹⁸. If participants require an allocation between two binding BAAs to be enabled, similar to what is done for transfer revenue in EDAM, the Markets+ Tariff allows for an allocation between binding BAAs. ¹¹⁹

Based on an assessment of these two approaches, Bonneville believes that the Markets+ constraint-level congestion rent design is more robust because it better recognizes the topology of the market footprint and directly aligns with how Bonneville models and manages transmission constraints. For this reason, along with the concerns regarding the EDAM design methodology for allocation of congestion revenue, Bonneville strongly supports the congestion revenue allocation methodology of Markets+.

5.2.5. Greenhouse Gas Accounting

Bonneville is not subject to any state GHG programs in the region. However, it is important to many of Bonneville's customers to maintain the low-carbon attributes of the federal system. The market design for GHG accounting—how resources and their associated emissions are assigned to market participants—is critical to ensuring Bonneville's customers can continue to claim the low-carbon attributes of the federal system to comply with various state-mandated GHG programs or for their own utility purposes. This is a particularly challenging area because the various state GHG-reduction programs have created a patchwork of inconsistent policy goals and economic drivers across the West that can be challenging for utilities to navigate in wholesale power markets. EDAM and Markets+ meet the GHG accounting needs of states and participants in two ways.

First, a dispatch-based solution has been developed that supports state carbon pricing programs like California's cap-and-trade program and Washington's cap-and-invest program. The dispatch-based solutions incorporate a price on carbon for generation located in the state subject to the state program and electricity imports to the state. The market optimization selects resources to be attributed to serving load in the state based on the most economically efficient outcome for the market, including the carbon price for the applicable state.

Second, out-of-market (i.e., non-dispatched based) tracking and reporting mechanisms are being developed to support the needs of states and participants generally. This accounting supports a participant's ability to claim their owned and contracted resources for GHG reporting purposes. Bonneville considered how a day-ahead market GHG accounting design will impact Bonneville's customers across the region. Bonneville believes that a market design must address GHG accounting in a way that works fairly and equitably for all participants and states and does not

¹¹⁵ See SPP Markets+ Tariff, Attach. A § 7.16 (Congestion Rent Eligible Transmission Service Reservation Verification).

¹¹⁶ *Id.* § 7.16 (Congestion Rent Eligible Transmission Service Reservation Verification).

¹¹⁷ *Id.* § 9.2.15 (Day-Ahead Excess Congestion Rent Allocation Distribution Amount).

¹¹⁸ This monitoring plan was approved as part of the MCRTF protocols. SPP, Markets+ Monitoring Metrics Congestion Rent (Aug. 14, 2024), *available at*:

<https://www.spp.org/Documents/72193/Congestion%20Rent%20Monitoring%20Approach%20Clean.docx>.

¹¹⁹ SPP Markets+ Tariff, Attach. A § 7.16 (Coordinated Interchange Scheduling Limits). Similar to the EDAM design, this language allows for either a 50/50 allocation or another mutually agreed upon ratio.

prioritize a single state's policy.

Generally, day-ahead markets can improve GHG accounting by providing greater transparency and granularity of dispatch data, providing more specific emissions information associated with serving load inside the market footprint.¹²⁰ In recent years, markets have needed to develop solutions for addressing GHG accounting to support state program requirements and individual participant needs. Where state programs have enacted a price on GHG emissions, the market needs a way to determine what is least-cost for the entire market and simultaneously least-cost for meeting load in a state with the pricing program. In addition, the market needs a method for assigning dispatch of specific resources (and their associated emissions) to specific loads to support the GHG reporting needs and emission reduction goals for states and individual utilities.

GHG accounting and reporting for organized markets is an actively evolving area with markets developing solutions to meet state program GHG requirements and state programs updating rules to adapt to market design. There are still uncertainties about how organized market GHG accounting will work with state GHG reporting, and additional uncertainties as to how this transpires into the GHG reporting provided to states for purchases from the federal system. While Bonneville cannot provide explicit details on what GHG reporting will look like for Bonneville's customers with participation in a day-ahead market, significant progress has been made related to GHG market design and related state GHG reporting in recent years and there is sufficient information available to describe and assess generally how the market design will work. The GHG market designs are described below.

There is currently insufficient information to determine if joining a day-ahead market will increase or decrease emissions attributed to federal power purchases from Bonneville. There are a number of unknown factors that are material to overall emissions impacts, including what resources are participating in the market, the market's GHG tracking and reporting rules combined with state-specific GHG reporting requirements, and changes in market behaviors of participants (e.g., shifts from use of traditional bilateral markets to organized markets). Nevertheless, there is enough information available for Bonneville to determine that the Markets+ design is superior to the EDAM design as described below.

5.2.5.1. GHG Accounting for Carbon Pricing Programs

EDAM and Markets+ have developed solutions that dispatch and attribute least-cost resources (including GHG costs) to load in a carbon pricing state to support the needs of states with carbon pricing programs, like California and Washington. The market operators aim to meet the needs of states and utilities subject to the carbon pricing program without negatively impacting states and utilities without such a program. However, in many cases, challenging trade-offs are inevitable because the market must balance the differing policies of states with respect to GHG reduction.

Bonneville believes that Markets+ GHG accounting design for carbon pricing programs achieves a reasonable approach to a market design that supports states with carbon pricing programs while not unfairly impacting states and entities not subject to carbon pricing. Conversely, Bonneville finds that CAISO's design falls short. As explained below, Bonneville anticipates CAISO's current design could have adverse financial impacts to Bonneville's customers and jeopardize customers' abilities to continue to report the low-carbon attributes of their power purchases from the federal system. There are two fundamental differences in design features that lead Bonneville to this conclusion.

5.2.5.1.1. Markets+ "Type 1A" attribution ensures attribution of federal system power contracted to utilities in states with carbon pricing programs

For customers located in Washington and subject to the state's cap-and-invest program, Markets+ design is superior because it better supports customers' ability to claim the low-carbon attributes of the federal system. Markets+

¹²⁰ See, e.g., CAISO, Average Emissions Rate Report, available at <https://www.caiso.com/library/average-emissions-rate-reports>.

design (for “Type 1A” attribution of power to a state) will result in greater assurance that power from the federal system will be attributed to Bonneville’s Washington customers. Markets+ design allows participants to register resources as “Type 1A” if they have contracts with load in the GHG Pricing Zone.¹²¹ This “Type 1A” treatment recognizes that utilities have entered into contractual arrangements to procure clean or low-carbon energy and honors those contractual agreements by attributing the resource (if it is economical within the market dispatch) to load in the state. This “Type 1A” treatment is a critical feature that will allow customers to identify federal resource amounts that are contracted to its customers in Washington¹²² and the market design will ensure those resources are attributed to Washington load if dispatched.

The Markets+ design recognizes contractual commitments that meet certain qualifications as “Type 1A” resources. Type 1A resources are optimized in the same way as in-state resources, resulting in the inclusion of the appropriate GHG adder in the offer prices and attribution to load in the state with the GHG pricing program. Thus, the design ensures attribution of the low carbon attributes of the federal system to Washington loads that have contracted with Bonneville.

EDAM’s design recognizes contractual commitments¹²³ but not in an equivalent manner to Markets+ Type 1A treatment. EDAM’s design recognizes contractual commitments, but does not guarantee the federal system, if dispatched, will be attributed to Washington. The market will seek the most economic solution for the market, including the carbon pricing states (both California and Washington). The federal system could be dispatched and attributed to Washington or it could be dispatched and used to meet load in the rest of the market, when it is the most economical solution for the entire market footprint (this is more akin to Markets+ Type 1B).¹²⁴ Thus, EDAM’s design, if extended to Washington, would not provide the same level of assurance that federal power would be attributed to Washington loads. Further, EDAM does not appear to support assured attribution, even for self-scheduled resources (although, if it did, self-scheduling would not be an efficient market design because it would not allow for an optimized dispatch when appropriate).

EDAM’s market design, paired with the design of Washington’s cap-and-invest program, could dispatch fossil fuel generation located inside Washington to help meet power balance of the market as a whole, and attribute the resulting GHG emissions to load across Washington, including that of Bonneville’s preference customers. At the same time, less expensive federal power could also be dispatched by the market but not attributed to Bonneville’s power customers in Washington. This could occur because in-state resources¹²⁵ always have the GHG adder¹²⁶ in their dispatch, so the market optimization will by default first deem all in-state resources to be serving load inside the carbon pricing state, to achieve a least-cost solution for the entire footprint of the market. This could happen even if the market also dispatches a cheaper out-of-state clean resource that is contracted to Washington load. While this is a good solution for economic efficiency when considered across the entire market footprint, it can create unintended consequences for Washington loads that have contracts with clean or low-carbon resources located outside of the state. This inability to ensure federal power is attributed to Washington prevents Bonneville’s

¹²¹ See SPP Markets+ Tariff, Attach. K §§ 2, 3.2.2.

¹²² Currently, in Bonneville’s BAA, only its customers in Washington will have load included in a GHG Pricing area.

¹²³ See CAISO, Extended Day-Ahead Market Final Proposal § 7(c) and (d) (Dec. 7, 2022), *available at* <https://stakeholdercenter.caiso.com/initiativedocuments/finalproposal-extendedday-aheadmarket.pdf>.

¹²⁴ Type 1B is energy from a resource with an agreement to supply load inside a GHG pricing zone. Type 1B energy is only attributed to the GHG pricing zone if it is the most economic solution for meeting power balance for the entire market. See SPP Markets+ Tariff § 1 (Definitions, Type 1B Energy) and Attach. K § 3.2.3.

¹²⁵ In-state resources are generally resources physically located in the state with the GHG pricing program (e.g., Washington). However, pursuant to Washington’s Climate Commitment Act, the federal system is considered to be external to the GHG Pricing Zone. See Wash. Rev. Code § 70A.65.010(42)(c).

¹²⁶ A GHG adder represents the monetary value of an individual resource’s emission factor multiplied by the cost of compliance with the respective state program (e.g. cost of allowances). See CAISO EDAM Filing, Tariff § 29.32(a) (GHG Bid Adders); SPP Markets+ Tariff § 1 (Definitions, Specified GHG Adder).

Washington customers from claiming the low carbon attributes of the system and therefore equates to increased costs for Bonneville and its long-term firm power purchasers.

5.2.5.1.2. *Markets+ Baseline “Threshold” Run recognizes Bonneville’s load obligations in determining energy eligible for attribution, limiting the risk that energy contracted to other utilities will be attributed to states with GHG pricing programs*

For customers located outside Washington, Markets+ design (the “threshold enhanced floating surplus” approach)¹²⁷ gives Bonneville the ability to manage how much energy from the federal system can and cannot be attributed to load in a state with carbon pricing (referred to as a GHG pricing area). Bonneville expects that the low-carbon nature of the federal system will often make it a least-cost option (including GHG cost), and, thus, result in attribution to load in California or Washington. Markets+ design includes market mechanisms that largely limit the amount of energy (aside from contracted amounts) that can be attributed to a GHG pricing area to circumstances when that energy is surplus to a market participant’s total load obligations.

Markets+ design enables the resource owner to set a threshold reflective of the market participant’s load obligations. Markets+ uses a baseline run that takes those obligations (the “threshold”) into account by only making amounts dispatched over the threshold available for attribution to a GHG pricing area. The threshold run looks at the entire footprint of the market and is currently expected to run approximately every 15 minutes¹²⁸ and should yield results that are fairly aligned with the optimization and ultimate dispatch of the resource. In other words, the existing load obligations of the resource are a direct consideration of how much energy is eligible for and ultimately attributable to a GHG pricing area. This is a key feature of Markets+ design that would help ensure that Bonneville’s customers can continue to claim the low-carbon attributes of their federal system power purchases for applicable state programs or for their own purposes.

While the newly adopted EDAM design will allow a participant to indicate how much energy they are willing to attribute to a GHG pricing area,¹²⁹ there is no in-market mechanism that aligns the participant’s load obligations to the baseline run or optimization and resource dispatch. Rather, EDAM’s baseline run (the “reference pass”)¹³⁰ takes a broader look at resources across the market footprint to establish eligibility for attribution. As the CAISO explained in its EDAM filing, the EDAM counterfactual will “approximate how a balancing area outside the GHG regulation areas will meet its own load with its internal generation as well as supply from other balancing areas outside of the GHG regulation area. The goal of the GHG reference pass is to reflect how supply resources can optimally serve demand in the EDAM footprint without net imports into the GHG regulation areas and the associated cost of compliance with GHG regulation.”¹³¹ As a practical result of this, EDAM limits attribution of a resource to amounts that are determined to be surplus to the load needs of the entire market footprint rather than surplus to the participant’s load obligation.¹³²

Bonneville has two concerns with the EDAM design. First, this design incorrectly assumes that the best way to prevent leakage¹³³ is by assuming the load obligations of all market participants external to the GHG pricing area

¹²⁷ See SPP Markets+ Tariff § 1 (Definitions, Surplus Threshold) and Attach. K §§ 3.4, 3.7.

¹²⁸ Email exchange between Bonneville and SPP (on file with author).

¹²⁹ See CAISO, Extended Day-Ahead Market Final Proposal § 7(b)(3)(a) (Dec. 7, 2022), available at <https://stakeholdercenter.caiso.com/initiativedocuments/finalproposal-extendedday-aheadmarket.pdf>.

¹³⁰ See CAISO EDAM Filing, Transmittal Letter at 163-69; CAISO, Extended Day-Ahead Market Final Proposal § 7(b)(3)(c).

¹³¹ See CAISO EDAM Filing, Transmittal Letter at 163-69.

¹³² The EDAM excludes committed capacity from the baseline run. In other words, committed capacity will always be eligible for attribution to the GHG pricing area that the load it is contracted to is in.

¹³³ “Leakage” as used in this context is a reduction in GHG emissions within one jurisdiction that is offset by an increase in GHG emissions in another jurisdiction. See, for example, the definition of leakage in the California Global Warming

must be met before a resource could have surplus energy available for attribution to the GHG pricing area. This unnecessarily limits attribution from a particular resource, which may not be fully obligated (or obligated at all), which can disadvantage not only the seller of clean and low-carbon energy but also the state with the pricing program because the remaining resources eligible for attribution tend to be higher cost. Rather, the more appropriate measure is whether an individual resource (or system of resources, in Bonneville's case) has surplus energy available above its particular load obligations. As discussed above, Bonneville believes the Markets+ design appropriately focuses on energy amounts surplus to an individual resource's load obligations.¹³⁴

Bonneville notes that there is a related concern with CAISO's BAA net export constraint,¹³⁵ which limits attribution from resources in a BAA where that BAA is a net importer.¹³⁶ However, the BAA is also not the appropriate measure of whether an individual resource has surplus energy available to meet load in a GHG pricing area. While the Bonneville BAA as a whole may be a net importer, that does not identify whether individual non-federal resources or the federal system is surplus in relation to each resource's individual load obligations.

Second, under EDAM's design, the actual optimization could dispatch the resource at levels lower than those reflected in the reference pass, which could result in significant amounts of the federal system being attributed to California even though that power is contracted to Bonneville's customers in other states under long-term power sales contracts. While this can happen as well with Markets+'s design, the risk is minimized because, as discussed above, the threshold run is 1) based on all loads and resources in the market and 2) expected to be run every 15 minutes.

CAISO's existing market, the WEIM, demonstrates Bonneville's second concern. In the WEIM, there are often times when the amount of federal system WEIM dispatches that are attributed to California are greater than the amount that Bonneville's BAA is exporting to the WEIM. Specifically, when there is a non-zero GHG shadow price, meaning some carbon emitting resources are being attributed to California,¹³⁷ about 90% of Bonneville's WEIM power sales are being attributed to California. This occurs even though there may be a negative imbalance¹³⁸ in Bonneville's BAA (i.e., Bonneville BAA is importing from the WEIM) and customers have contracts with Bonneville for forward supply. A day-ahead market would subject a larger portion of the federal system to this effect. CAISO has taken recent steps to improve the GHG accounting design in EDAM by switching to a baseline

Solutions Act of 2006 (Assembly Bill 32, or AB32), *codified as* Cal. Health and Safety Code Div. 25.5, §§ 38500-99.11.

CAISO uses the term "secondary dispatch" to identify when leakage is occurring in its market design because a resource has been attributed to a jurisdiction (California) at levels below the resource's baseline.

¹³⁴ Bonneville notes that emissions leakage (also referred to as secondary dispatch in a markets context) is a state issue as opposed to a markets issue. Individual state programs may have differing views on whether leakage needs to be addressed and, if so, how stringently. CAISO's approach to minimize leakage is purportedly a California approach as the California Air Resource Board's cap-and-trade program was the only pricing program in effect with guidance on leakage at the time of EDAM development. Conversely, SPP's approach provides more state flexibility to determine parameters around the appropriate amount of leakage. This is because a resource owner's threshold can be informed by guidance from a state on what constitutes surplus energy that is eligible for attribution to the state.

¹³⁵ See CAISO EDAM Filing, Tariff § 29.32.1.

¹³⁶ The EDAM net export constraint does not apply when the BAA is located in a GHG pricing zone and does not limit committed capacity from being attributed to a GHG pricing zone.

¹³⁷ Bonneville uses its Asset Controlling Supplier emission factor to inform its GHG bid offer for California, resulting in a very low, but non-zero GHG emissions cost.

¹³⁸ The WEIM Transfer is an algebraic quantity (positive for export and negative for import) for the net energy exchange between a given BAA and the remaining BAAs in the WEIM Area. See CAISO Business Practice Manual for the Western EIM, Appendix A: Mathematical Formulation for WEIM Transfer § 16.2.1.1.1, *available at* https://bpmcm.caiso.com/BPM%20Document%20Library/Energy%20Imbalance%20Market/BPM_for_Energy%20Imbalance%20Market_V33_Clean.docx.

run¹³⁹ and adding the BAA next export constraint for EDAM. Bonneville expects that these updates will help reduce this effect but not minimize it as effectively as the Markets+ design. In the event this occurs in EDAM, it could undermine the ability for Bonneville's customers in other states, like Oregon, to claim energy from the federal system for GHG reporting purposes, despite the fact that they hold long-term contracts for federal system purchases.

5.2.5.2. GHG tracking and reporting for non-pricing programs and general needs of market participants

Both EDAM and Markets+ are also developing more broadly applicable GHG accounting solutions that could support meeting the requirements of states with non-pricing programs (e.g., emission reduction standards that do not explicitly place a price on carbon), as well as the GHG accounting needs of any individual market participant. Bonneville views these solutions as essential to its customers' ability to retain the GHG benefits of the federal system.

Markets+ has developed and adopted a novel out-of-market GHG accounting solution designed to support the needs of market participants, whether to meet requirements of a state non-pricing program, local requirements, or individual utility goals.¹⁴⁰ The accounting framework will assign to a market participant the dispatched energy for the market participant's owned and contracted-for resources up to the amount of the market participant's load. This will ensure (subject to state GHG reporting rules) that market participants can claim and report the clean resources in which they have invested. Bonneville has confidence that the Markets+ solution will support Bonneville's customers' ability to continue to claim the low-carbon attributes of the federal system regardless of the state in which the customer is located.

EDAM work to develop a similar approach is in progress.¹⁴¹ In December 2024, CAISO published an issue paper that outlines reporting design options and some tradeoffs.¹⁴² It is uncertain whether the approach CAISO ultimately adopts will support the needs of Bonneville customers. At this time, Bonneville has more confidence that the Markets+ design for accounting and reporting will meet the needs of its customers.

5.2.5.3. GHG Takeaways

Markets+ includes a GHG accounting design that fairly assigns Bonneville's carbon-free generation to Oregon and Washington customers. The EDAM design continues the status quo of California customers obtaining disproportionate credits for out-of-state low-carbon generation. As these market design differences persist, they serve to increase costs for Bonneville's Washington customers who participate in Washington's carbon pricing program, and they result in Oregon customers receiving less credit than they are entitled to meet their state's requirements.

As described above, Bonneville has made an informed comparison between the market designs of EDAM and Markets+ related to GHG accounting. Bonneville believes that the Markets+ GHG accounting approach (the dispatch-based solution for carbon pricing programs combined with a broadly applicable out-of-market resource

¹³⁹ The EIM currently limits attribution of a resource to a GHG pricing area to the difference between the resources Upper Economic Limit and Base Schedule. In the future, for EDAM participants, the CAISO will use the difference between the day-ahead market energy schedule and day-ahead market GHG award. *See id.* § 11.3.3.2; CAISO Extended Day-Ahead Market Final Proposal § 7(b)(3)(c).

¹⁴⁰ *See* SPP, Markets+ GHG Task Force, available at <https://www.spp.org/stakeholder-groups-list/western-energy-services-stakeholder-groups/marketsplus-stakeholder-groups/marketsplus-independent-panel/marketsplus-participant-executive-committee/marketsplus-design-working-group/marketsplus-ghg-task-force/>; SPP Markets+ Protocols § 5.8 ([GHG] Tracking and Reporting).

¹⁴¹ *See* CAISO, Greenhouse Gas Coordination Work Group, available at <https://stakeholdercenter.caiso.com/StakeholderInitiatives/Greenhouse-gas-coordination-working-group>.

¹⁴² CAISO, Greenhouse Gas: Accounting and Reporting Issue Paper (Dec. 20, 2024), available at <https://stakeholdercenter.caiso.com/InitiativeDocuments/AccountingandReportingIssuePaper-GreenhouseGasCoordination-Dec202024.pdf>.

and emissions assignment available to all market participants) is an equitable approach to the needs of all market participants to meet various reporting programs, and provides a path for Bonneville's customers to continue to report low-carbon attributes associated with purchases from Bonneville. Further, the Markets+ governance structure enabled it to successfully continue to refine a widely supported solution for GHG accounting. In addition, SPP's stakeholder process provides superior flexibility, allowing participants the opportunity to revise the GHG accounting design to account for changes in the GHG reporting landscape. Bonneville recognizes the market participants' ability to make stakeholder-driven improvements and adjustments to market design is particularly important in this complex and evolving area.

5.3. Summary Recommendation

Bonneville recognizes that its day-ahead market Policy direction towards participating in Markets+ will play a critical role in the energy and capacity market landscape for the region, and it will have direct impact on a number of other entities' decisions regarding day-ahead market participation. Bonneville has carefully considered the financial analyses, design comparisons, expected footprints, and various other details through the lenses of our evaluation principles. Bonneville sees participation in a day-ahead market as an important step in maintaining access to trading partners to continue meeting obligations and marketing surplus to maintain low rates for customers.

Bonneville has determined that Markets+ is the best option because of its superior governance and stakeholder process and its superior design, and believes it has the potential to offer financial benefits that are greater than business as usual. While several market design issues described above, such as congestion revenue allocation, GHG accounting, and fast start pricing, cannot be decisively quantified, Bonneville believes the Markets+ design is likely to provide economic benefit and partially offset the financial benefits attributed to EDAM by the PCM studies. Bonneville will work diligently to meet the needs of its power and transmission customers, including by maintaining access to trading partners and minimizing market-to-market friction. Bonneville acknowledges the potential financial tradeoff and potential increased implementation and participation complexity given differing decisions by other adjacent entities. However, these tradeoffs must be evaluated along with potential mitigation and the business drivers associated with relevant quantitative and qualitative factors. Based on comprehensive business evaluations presented in this Policy, Bonneville concludes that the design of Markets+ is best positioned to satisfy Bonneville's business needs, statutory and contractual obligations, and the broad and evolving needs of Bonneville's customers.

6. Preliminary Implementation and Participation Considerations for Markets+

Throughout Bonneville's public process, Bonneville explained generally how a day-ahead market will affect Bonneville and its customers. Bonneville discusses a summary of Markets+ implementation and participation elements in this section. Further details will continue to be developed as Bonneville progresses through implementation of day-ahead market participation in Markets+.

Bonneville's Policy direction to join Markets+ impacts all generation and load in the Bonneville BAA to some degree. In addition to requirements laid out in the market tariff and associated supporting documentation, Bonneville will memorialize requirements and rate information specific to its BAA in its tariff, rate schedules, and business practices as part of the public processes it carries out for each of these documents.

6.1. Generation Resource Participation in Markets+

Bonneville anticipates the following details of participation framework in Markets+.

All output is settled

In Markets+, all resources above a certain size¹⁴³ in Bonneville's BAA will be subject to the market tariff and rules,

¹⁴³ In the WEIM, Bonneville requires all generators above 3 MW to be modeled. See Bonneville Power Administration, Energy Imbalance Market (EIM) Business Practice V.5 §§ D.3, G.6 (May 30, 2023).

which Bonneville will propose to incorporate into its Tariff and business practices.¹⁴⁴ Under the terms of the Markets+ Tariff, all generation output will be settled at market prices.¹⁴⁵ The basic energy settlement equations are described in Section 6.6.¹⁴⁶

All resources participate, but can self-schedule

In the context of the WEIM, “participating resources” are resources registered directly with the WEIM that can offer flexible range to the market via a bid curve, and “non-participating resources” are all other resources that do not bid directly into the market. In both day-ahead markets, all resources are considered “participating” because their full output impacts the market solution, and they are settled for that full output. However, this does not mean that all resources must offer flexibility. In addition to the ability to offer price-sensitive energy between a minimum and maximum generation point, both markets also allow for “self-scheduling” which is an indication to the market that a resource plans to generate a specific MW amount and is not offering price-sensitive flexibility to the market. The resource will still be settled for that submitted self-schedule at the relevant market LMP, as the submitted self-schedule becomes the day-ahead market solution award for that resource, and that resource will still be settled for real-time output relative to that day-ahead award.

Resources can still export out of the BAA

Joining Markets+ will not prevent or limit resources in the Bonneville BAA from transacting with entities outside the Markets+ footprint. Entities can still export from their resources out of the footprint as long as the export is properly tagged, as is required today to sell an export out of the Bonneville BAA. Note that this does not require a resource to opt their transmission out of the market. Resources can schedule on their transmission to indicate the export, and then either self-schedule enough output to serve the export or offer the resource into the market and let the market choose the most economic resource mix to serve the export obligation. This is further discussed in section 6.8.

Resources and loads must have a direct relationship with the Market Operator

In Markets+, all registered resources and loads must have a direct relationship with the Market Operator via a Market Participant¹⁴⁷ Agreement. Multiple resources and multiple loads can be registered under a single market participant. The market operator will directly receive data submissions from the market participant and will settle directly with the market participant for nearly all charge codes. This differs from the WEIM framework, where the market settles with the BA for all loads and non-participating resources and the BA subsequently sub-allocates the charges. At this time, Bonneville has not determined whether it will offer options for resources in its BAA to schedule into the market through Bonneville (e.g., simply by submitting a schedule to Bonneville via e-tag or Bonneville’s Customer Data Exchange, as is done for non-participating resources in the Bonneville BAA for WEIM today). Note that for the few charge codes paid to the TSP or BA, Bonneville will determine the suballocation of those funds in a future Rate Case proceeding.

Independent resources do not have an automatic must-offer obligation

The Markets+ Must-Offer Obligation is measured at the market participant level. Independent resources do not have individual must-offer obligations unless they have export schedules (in which case, they must offer or self-schedule their resource to fulfill the export schedules). Otherwise, individual resources contribute to meeting the Must Offer

¹⁴⁴ See Section 5.1.1.6 (Power Business Line) above and Section 6.6 (Markets+ Settlements) below for more details.

¹⁴⁵ SPP Markets+ Tariff, Attach. A § 6.2(6). An MP must register all gen in footprint above 0.1 MW unless behind the meter under 10MW (note: the BPA BA uses 3MW, not 10MW, for BTM in EIM, as indicated in the previous footnote).

¹⁴⁶ See also SPP Markets+ Tariff, Attach. A §§9.2 (Day-Ahead Market Settlements), 9.3 (Real-Time Balancing Market Settlements).

¹⁴⁷ Pursuant to the Markets+ Tariff Definitions: “Market Participant (MP): An entity that executes the Market Participant Agreement in Attach. E, or on whose behalf an unexecuted Market Participant Agreement has been filed at FERC.”

Obligations of market participants with load by being a resource within that market participant's registration. The market participant can also indicate a contract with the resource that they put toward their must-offer obligation.

Resources must provide offer information in accordance with market timing

The timing for the day-ahead market run to "close" (at which point the day-ahead market optimization begins, and no new input information can be incorporated) in Markets+ is 10 a.m. on the day prior to the relevant operating day, with results expected to be posted by 1:30 p.m. Markets+ runs the Reliability Unit Commitment (RUC) process at least every four hours between the day-ahead market solution and real time. The RUC provides unit commitment information to resources that have indicated their willingness to be committed by the market but is otherwise not financially binding for purposes of energy settlement. The timing for the real-time market run to close is 30 minutes prior to the relevant operating hour ("T-30"). Offer information, including MW amounts and associated pricing, can be changed after the 10 a.m. day-ahead close at any point until the T-30 deadline and is incorporated into any subsequent RUC and real-time optimizations.

Potential for non-BA requirements

Note that the information in this section generally pertains to participation based on Markets+ requirements and the expected framework in the Bonneville BAA. For resources that are owned by or contracted to power customers of Bonneville Power Services, there may be further requirements. Those requirements will be determined as part of a public process as discussed in Section 6.7.

6.1.1. Federal Generation

Markets+ will allow resources to be registered as individual units or as aggregated resources. Bonneville intends to use the same resource aggregations as is used in WEIM. Resource aggregates are further discussed in Section 6.1.1.2.

Bonneville will prioritize its statutory obligations such as fish passage and flood control over market actions, as it does today, which may limit Bonneville's ability to participate in the market during times of limited hydraulic flexibility.

Bonneville expects to use self-schedules and offer ranges to ensure the FCRPS operates within its limits while allowing for system optimization. In addition to hourly minimum/maximum constraints, Markets+ has also developed an additional constraint, allowing Bonneville to communicate a daily energy maximum for each resource in the day-ahead optimization in addition to the hourly offer range limits. Setting a daily energy maximum helps ensure that Bonneville can honor operational obligations and constraints while still allowing for economic optimization of the system. Further, because offers can be updated through real-time, Bonneville will be able to make adjustments to its planned operations in the market as fuel certainty materializes.

6.1.1.1. Impacts on Hydro Operations in Relation to Fish & Wildlife

In Markets+, Bonneville will continue to meet its statutory obligations, including those under the Northwest Power Act, Endangered Species Act (ESA), and National Environmental Policy Act (NEPA). Bonneville's power marketing services and activities, and its actual power operations to meet load obligations, are conducted consistent with applicable Biological Opinions and are within existing operating constraints and normal operating limits of FCRPS projects. The Markets+ framework allows Bonneville to manage FCRPS operations with other project purposes and system-wide operating constraints, including operations to support ESA-listed fish and to provide equitable treatment for fish and wildlife with other system purposes as required by the Northwest Power Act.

6.1.1.2. Use of aggregation model for Federal resources

As part of the decision to enter the WEIM, Bonneville opted to use the aggregation model to represent the Big 10

hydro resources.¹⁴⁸ The aggregation model has worked well in the WEIM, and Bonneville plans to maintain this approach for day-ahead market participation in Markets+.

The resources within an aggregation model are hydraulically interdependent; water released out of upstream resources will affect the operation of downstream resources within a matter of hours. Hydro operators must account for this relationship along with fuel uncertainty (e.g., expected water flows versus real water flows due to weather, third party resource operations, etc.). This dynamic, combined with the various non-power constraints and physical project limitations, results in the need for hydro operators to have flexibility to adjust between resources as necessary. Aggregation of hydro resources allows Bonneville and its federal partners to maintain this flexibility to manage the impacts of market activity and uncertainty in operational and hydraulic objectives.

In the WEIM, Bonneville uses three aggregations to provide maximum flexibility for hydro operators while providing the market with maximum ability to redispatch resources for congestion relief. Bonneville grouped the resources that were most interconnected based on river reach area (Upper Columbia,¹⁴⁹ Lower Snake,¹⁵⁰ and Lower Columbia¹⁵¹ areas).¹⁵²

Bonneville has worked closely with SPP and stakeholders in the Markets+ process to design an aggregation model for use in Markets+. Bonneville has not yet determined if there are other groups of resources in the federal hydro system that would benefit from aggregation but plans to consider that question during implementation.

6.2. Ensuring Adequate Supply in Markets+

Today, Bonneville works across all timeframes to preserve and maximize the value of the FCRPS for customers through prudent operational planning and marketing practices. Bonneville sets its system up to provide the most economic and reliable energy supply to customers while planning for contingencies and required operations such as those for fish and wildlife. Bonneville also plans the system to make economic purchases and high-value surplus sales to bring added revenue to help lower firm power rates. Bonneville's primary goal in its proposed participation in Markets+ will be a continuation of what it does today: provide firm power supply for its long-term power sales contracts. Bonneville will continue to plan for its long-term firm power load service obligations by managing its existing resources and by acquiring resources in advance based on forecasted need. Bonneville does this in its Pacific Northwest Loads and Resources Study (also known as the White Book) and through its Resource Program, both of which supplement the regional power plan prepared by Northwest Power and Conservation Council pursuant to the Northwest Power Act.

Bonneville's future participation in WRAP binding operations and Markets+ will provide greater transparency and documentation as to how these obligations are met. Bonneville's loads and resources planning for its long-term power customers will be reflected for long term planning in its WRAP obligations and for short term planning in the requirement that Bonneville meet the Markets+ resource sufficiency mechanism, the Must Offer Obligations. The Must Offer Obligation is a minimum requirement for each market participant in Markets+ with load and/or export obligations to bring enough supply to "cover" those obligations. Through its long-term planning (reflected in the WRAP Forward Showing program and Bonneville's White Book), and its short-term planning practices (demonstrated in the Must Offer Obligations and WRAP Operations Program), Bonneville will ensure that its long-term firm power sales contract obligations are satisfied.

¹⁴⁸ The "Big 10" Hydro Resources are: Grand Coulee, Chief Joseph, Lower Granite, Little Goose, Lower Monumental, Ice Harbor, McNary, John Day, The Dalles, and Bonneville Dams.

¹⁴⁹ Aggregation of Grand Coulee and Chief Joseph Dams.

¹⁵⁰ Aggregation of Lower Granite, Little Goose, Lower Monumental, and Ice Harbor Dams.

¹⁵¹ Aggregation of McNary, John Day, The Dalles, and Bonneville Dams.

¹⁵² For more information on this decision, please see Bonneville Power Administration, EIM Participation Letter to the Region, Attach. A § III.e.1 (June 20, 2019), available at <https://www.bpa.gov/-/media/Aep/projects/energy-imbalance-market/20190620-western-energy-imbalance-market-letter-to-the-region.pdf>.

6.3. Ancillary and Control Area Services

Ancillary and Control Area Services (ACS) are services necessary to support the transmission of energy and capacity while maintaining reliable operation within and among BAAs. Bonneville is required to offer ancillary services under its Tariff, and transmission customers may purchase certain ACS from Bonneville or self-supply through a customer's own resources. In general, ACS are necessary to maintain the reliability of the BAA. There are typically two components to most ACS: capacity (the ability to produce energy when needed) and energy (the actual production of energy). Energy and Generation Imbalance, which are used for the sub-hourly provision of energy to maintain load-resource balance within the BAA, are two important ACS that Bonneville currently offers. Bonneville currently provides Energy and Generation Imbalance service through the WEIM under Schedules 4E and 9E of Bonneville's Tariff.¹⁵³ There is currently no centrally organized market for the capacity component of ACS proposed for Markets+ or EDAM, which Bonneville provides under Schedules 3 and 10 of its Tariff.

Participation in Markets+ does not eliminate Bonneville's requirement to offer ACS, as the market operator will not be taking over this responsibility. Markets+ includes the Real-Time Balancing Market (RTBM), which is similar to the WEIM. The RTBM is an intra-hour (or real-time) centralized energy market used to economically dispatch participating generation resources to balance supply, transfers between BAAs (interchange), and load across the market's footprint. Like the WEIM, RTBM is not a capacity market. Bonneville does not expect Markets+ to change how ACS is provided. However, Bonneville will likely need to revise its tariff, rates, and business practices to incorporate Markets+. Those revisions will occur separately in the appropriate processes.

6.4. Operational and Commercial Seams

As described by FERC, seams issues include differences in transmission rules as well as differences in power market rules. Operational seams include multifaceted matters such as coordination of generation and transmission maintenance schedules, determining how path flows affect outside areas, congestion management procedures, operating rules for recalling firm transmission capacity, demand response rules, and communication protocols. Commercial seams encompass different market constructs such as bidding rules, market product definitions, market price intervention practices, different business practices, generation and transmission scheduling practices, and processes to verify transactions between market operators and market participants.¹⁵⁴

Bonneville and other BAAs will need to manage new operational and commercial seams as entities join day-ahead markets. For example, Bonneville has generation and load in other BAAs that are likely to join EDAM, such as the PacifiCorp (PAC) and Portland General Electric (PGE) BAAs. In addition to the obligation to customers located in those BAAs, many entities affected by the implementation of day-ahead markets will need to manage commercial seams and possibly multiple markets. These seams can be mitigated through coordination across the various participants, including market operators, BAAs, market participants, and the various regional groups who coordinate among WECC today.

As explored in detail in Appendix D, the development of day-ahead markets will create new operational seams in the Western Interconnection. Bonneville's transmission system covers large portions of the Pacific Northwest and is not always contiguous. There are also a number of transmission asset owners, BAAs, and transmission capacity owners of operational paths within Bonneville's Pacific Northwest service territory, including the Pacific DC Intertie (PDCI) and Northwest AC Intertie (NWACI). Bonneville will be able to manage operational complexities like congestion management by developing coordinated operating agreements like those for WEIM.

CAISO and SPP will have their own RC offerings tasked with ensuring system reliability for their registered

¹⁵³ Bonneville is providing imbalance service under Schedules 4 and 9 during the periods that Bonneville pauses WEIM participation.

¹⁵⁴ *Remedying Undue Discrimination Through Open Access Transmission Service and Standard Electricity Market Design*, 67 Fed. Reg. 55,452 55,464-65 (Aug. 29, 2002).

Transmission Operators. RCs, market operators, and market participants will develop agreements to manage seams to support reliable operations, like they have in the eastern states for decades. The ability of a region with multiple energy markets in it to effectively manage congestion is strongly dependent on both markets calculating impacts on a path the same way, so that actions taken during congestion management have the desired effect in both market footprints.

6.4.1. Commercial Seams

As also explored in detail in Appendix D on seams management, the development of day-ahead markets will create new commercial seams. Today, many of Bonneville's commercial seams are between the bilateral and non-bilateral markets. The industry has created tools and means of transacting which mitigate the impacts of these commercial seams such as ensuring power sales and purchases have some uniform provisions by largely adopting the WSPP, Inc. (formerly Western Systems Power Pool) standardized WSPP Agreement.¹⁵⁵ Multiple day-ahead markets within the West would require the development of new tools and methodologies to manage commercial seams.

6.4.2. How market participation may impact transmission congestion issues

Bonneville has observed the ability of WEIM to manage operational constraints and expects even greater congestion management effectiveness with the addition of a security constrained day-ahead market optimization. However, Bonneville acknowledges that two day-ahead markets will create a need for operational coordination between the markets, particularly given the non-contiguous nature of the potential market footprints. The ability of an energy market to effectively manage transmission system congestion depends on the footprint and size of that market. This includes the size, location, and offered flexibility of the resources supplying energy to that market, the size and location of the loads purchasing that energy, and the volume of transmission available to that market relative to those resources and loads. The day-ahead schedules and awards from each market, if properly implemented and coordinated, should be physically feasible within the market-available transmission capacity.

Bonneville is likely to have generation, load, and transmission participating in or impacted by both markets. Appendix E discusses in more detail those impacts as they are related to congestion management. Bonneville expects agreements, constraints, and market design to mitigate operational and commercial seams issues. Given the complexity of the Western Interconnection, the potential for non-contiguous market and RC footprints, and the number of parties involved, multiple types of agreements will be necessary.

6.5. Operational Tools

Bonneville employs many operational tools to reliably operate the federal power and transmission systems to meet its Tariff, compliance, and environmental requirements. At this time, Bonneville expects to continue to use a majority of these operational tools in Markets+.

Some of these tools will require adjustments to work within the framework and day-ahead market timelines of Markets+. Bonneville will continue to identify which operational tools will require adjustments as part of implementation scoping and will work with the market operators as necessary as part of that scoping process.

6.5.1. Curtailment Advisor

Bonneville anticipates adjusting its Curtailment Advisor tool used for performing transmission curtailments in real time when flow on a path exceeds the established limit. Today, when initiated, Curtailment Advisor curtails e-tag schedules impacting the given path in real time according to NERC curtailment priority. In the real-time market, the market optimization will redispatch every five minutes in real-time to maintain market flows within the established market transmission limit. If the market is unable to redispatch enough to avoid violating the limit, responsibility reverts to the TOP to determine if actions are needed to protect the path. However, because BAA-to-BAA e-tags with "system" sources are typical in a day-ahead market framework, Bonneville will need to develop

¹⁵⁵ See *WSPP, Inc.*, FERC Docket No. ER25-178, Letter Order (Dec. 13, 2024).

a method to address effective transmission curtailments based on NERC priority. Bonneville anticipates working through this topic as part of its implementation phase.

6.5.2. Operational Controls for Balancing Reserves (OCBR)

OCBR is a real-time operational tool used by Bonneville to manage reliability when balancing reserve capacity is depleted. Balancing reserve capacity is capacity held to address sub-hourly load and generation error as measured against an hourly schedule across the Bonneville BAA. Incremental or “INC” capacity is deployed when there is under-generation relative to load and decremental or “DEC” capacity is deployed when there is over-generation relative to load.

Before Bonneville’s entrance into the WEIM, the use of OCBR for an INC depletion event resulted in the curtailment of hourly schedules to actual generation levels for significantly under-generating resources. The use of OCBR for a DEC depletion event resulted in limiting generation to the scheduled amount for significantly over-generating resources.

Upon joining WEIM, Bonneville adjusted the design of the OCBR tool to better fit with the real-time market structure and leverage the additional sub-hourly energy available in the market. For example, Bonneville shifted the measurement of balancing reserve depletion to consider only the portion of balancing reserves served exclusively by Bonneville’s own resources (regulation), and not the portion served by WEIM dispatches (non-regulation).

Bonneville expects few, if any, changes to OCBR when joining Markets+. OCBR¹⁵⁶ is a real-time tool and the day-ahead market elements of Markets+ should not have any impact. As RTBM in Markets+ operates similarly to the WEIM, OCBR should work with the RTBM in the same manner.

6.5.3. Oversupply Management Protocol

Oversupply Management Protocol (OMP) is an operational tool used to address certain environmental conditions in the Columbia River, while maintaining reliability in Bonneville’s BAA. During times of high river flows, typically in the spring when loads in Bonneville’s BAA are low, water must be passed through the dams in one of two ways: spilled over the dams or run through the turbines to generate electricity. When water is spilled over the dams, it creates bubbles of air in the water that, at certain levels, can be harmful to salmon and other aquatic species. This is referred to as total dissolved gas and is regulated by Oregon and Washington under the Clean Water Act.

When the Columbia River reaches total dissolved gas limits, Bonneville must limit spill by passing water through the generating turbines, thus creating electricity. Bonneville sells this electricity at market rates, but, in the Spring, there are occasions when there is not sufficient load to use the electricity, even at zero cost. As a result, Bonneville adopted Attachment P to its Tariff, creating a least-cost cost curve for displacing generation in the BAA and reimbursing displaced generators for certain costs related to the displacement so that Bonneville can pass water through its generating turbines and maintain load-resource balance. Attachment P has been approved by FERC under section 211A of the Federal Power Act.

Bonneville expects to retain OMP in Markets+ and will review if any process changes are necessary to adapt to market rules and timing. While Markets+ may provide Bonneville additional opportunities to market generation during times of high flows, Bonneville still needs a mechanism to ensure compliance with its environmental responsibilities. As Bonneville gains more experience in Markets+, it will monitor the need to adjust or retain OMP.¹⁵⁷

¹⁵⁶ See Bonneville Power Administration, Operational Controls for Balancing Reserves, available at www.bpa.gov/energy-and-services/transmission/ancillary-services/balancing-reserves/operational-controls-for-balancing-reserves.

¹⁵⁷ See Bonneville Power Administration, Oversupply, available at www.bpa.gov/energy-and-services/transmission/oversupply.

6.6. Markets+ Settlements

Markets+ will settle directly with each market participant for the majority of its charge codes, including day-ahead awarded energy and imbalance energy. Settlement volume will be larger in a day-ahead market than in a real-time only market. As discussed in section 6.7, Bonneville expects to be the market participant on behalf of Load Following customers in the Bonneville BAA and thus will settle with Markets+ on behalf of those customers. Other market participants¹⁵⁸ will receive their settlements directly from Markets+.

Markets+ settlements are more streamlined than EDAM. Markets+ utilizes a simpler 12-month settlement process with three settlement statements and ~40 charge codes, as opposed to the EDAM settlement period of 24-months with five settlement statements, and a much larger number of charge codes to manage.¹⁵⁹ Markets+ settles directly with market participants. Receiving settlements directly through the Market Operator, rather than suballocated by the BA, as is done in WEIM, allows for more direct payments and charges, as well as more timely financial resolution. These aspects are likely to be especially favorable to independent power producers and other larger participants, as well as to Bonneville and its customers, by reducing the workload and associated costs of handling settlements for large entities within the BAA.

While there are a number of charge codes, the most essential settlements are for day-ahead energy awards and real time imbalance energy. As previously described, the award from the day-ahead solution is settled at the day-ahead LMP and is used as the financial reference point for settlement of energy in the real-time solution.

The general equation for energy settlement¹⁶⁰ for a resource is:

Total Energy Settlement = Day-Ahead Award * Day-Ahead LMP + ((Real-time Output – Day-Ahead Award) * Real-time LMP)

And for a load is:

Total Energy Settlement = -1*(Day-Ahead Cleared Load * Day-Ahead LMP + ((Real-time Load Consumption – Day-Ahead Cleared Load) * Real-time LMP))

In the load settlement equation, multiplication by -1 indicates a settlement in the opposite direction (i.e., a payment versus a charge).

6.7. Bonneville Power Services Customer Participation in Markets+

Bonneville's participation in Markets+ will be consistent with the obligations of its Provider of Choice power sales contracts. These contracts include the terms and conditions of the products and services that Bonneville offers its power customers and defines the obligations that both Bonneville and the power customer must meet. Bonneville will look to accommodate power customers' participation in the market consistent with the obligations associated with their product and service elections.

Bonneville recognizes that it does not currently have enough information to include language in the ongoing development of its next long-term power sales contract that would adequately address all the necessary day-ahead market terms and conditions. The Provider of Choice power sales contracts will include a provision that will enable the parties to amend the power sales contracts as needed. Such amendments will include any necessary changes to align with both an updated Bonneville Tariff and the Markets+ Tariff (including associated settlements under Markets+). Bonneville will hold a public process to review proposed standardized amendment language and offer an opportunity for public comment on that language. The Provider of Choice power sales contracts will also include

¹⁵⁸ E.g., Planned Product customers, independent power producers, etc.

¹⁵⁹ Bonneville has federal resources and preference loads in EDAM BAAs, so to the extent settlements are required, Bonneville will coordinate with EDAM or its participating BAAs and affected customers.

¹⁶⁰ Day-ahead markets contain many other charge codes. This is a simplified example showing basic energy settlement.

a provision establishing that Bonneville will conduct a subsequent public process on the topic of settlements for the Slice Product following Bonneville participating in the day-ahead market.

For Load Following customers, Bonneville expects to be the market participant on behalf of customer loads that are in the Bonneville BAA. Bonneville will work with Load Following customers with load outside the Bonneville BAA to determine the appropriate participation model. Load Following customers for which Bonneville is the market participant and that have dedicated non-federal resources may be eligible to have those resources participate in the day-ahead market consistent with their contractual obligations and requirements. For example, Load Following customers with dispatchable resources may be allowed to offer flexibility to the day-ahead market. Bonneville expects that Load Following customers that elect to offer their own resources into the market for dispatch would be expected to offer capability to the market consistent with any peaking requirements defined in their contracts.

Planned product customers include Slice/Block customers and Block customers. For planned product customers that are in the Bonneville BAA, Bonneville anticipates that a planned product customer will act as the market participant for both their own load and any non-federal resources they wish to bid into the market. Bonneville will work with planned product customers with load outside the Bonneville BAA to determine the appropriate participation model. Bonneville will work with planned product customers to determine how the power supplied by Bonneville is accurately reflected in both Bonneville's and the planned product customers' market participation. Planned product customers will continue to purchase power consistent with their planned obligation and would be expected to be responsible for any day-ahead or real-time load variances.

As an overall observation, Bonneville does not expect day-ahead markets to impact certainty of delivery for power customers. Bonneville would continue to schedule contract deliveries in advance of the market operation based on existing transmission rights as necessary. Transmission customers would continue to be entitled to the same curtailment priority under Bonneville's Tariff as they are today. The market dispatch, however, would account for transmission constraints and attempt to redispatch around them, reducing the need for curtailment and improving certainty of delivery.

6.8. Bonneville Transmission Services Customer Participation in Markets+

Bonneville's Tariff provides two types of Transmission Service: PTP¹⁶¹ Service and NITS.¹⁶² PTP Service allows the customer to move power from a Point of Receipt to a Point of Delivery and is billed on reservation capacity. NITS is available only for service to network load, billed based on metered network load, and includes planning obligations. Markets+ is consistent with the current terms and conditions for transmission service set under the existing Tariff to a great extent, including through the administration of the Open Access Same-Time Information System, and sale of firm and non-firm transmission service. The Markets+ design recognizes that the market does not assume the role of TSP and respects the prevailing OATT framework in the West.

With day-ahead market participation, Bonneville is anticipating some changes in how its customers may utilize their Bonneville transmission rights. Bonneville transmission contract holders will still have the ability to exercise their transmission rights (e.g., schedule, redirect, and resale existing transmission rights) consistent with Bonneville's Tariff, business practices, and any other relevant agreements as they do today during the day-ahead and real-time horizons, though there may be different implications of doing so.

Bonneville shared its preliminary assessment of how transmission may work in a day-ahead market construct at the

¹⁶¹ Bonneville Power Administration, Point to Point Transmission Service (PTP): An Overview (rev. Oct. 1, 2001), available at <https://www.bpa.gov/-/media/Aep/transmission/ptp-service/ptp-product-overview.pdf>.

¹⁶² Bonneville Power Administration, Network Integration Transmission Service (NT): An Overview (rev. Nov. 10, 2001), available at <https://www.bpa.gov/-/media/Aep/transmission/nt-service/nt-product-overview.pdf>.

public workshop 8 on July 18, 2024.¹⁶³ Bonneville shared a Markets+ process timeline for transmission activities for both the TSP/BA and the transmission customer perspective highlighting the complete cycle from pre-market (registration and modeling set-ups) to day-ahead and real-time activities and concluding with settlements. Bonneville provided examples of how transmission rights, both available for the market and opted-out, would be communicated to the market operator along with the associated Service Flow Constraints¹⁶⁴ (SFCs) that will be configured into the market operator's system(s).

By default, Bonneville's transmission customers' transmission rights and unsold ATC will be made available to the market unless specifically opted out as described in the next paragraph. As described in the day-ahead market framework Section 2.4, on a day-ahead basis, Bonneville will communicate the available transmission capacity on various paths to the Market Operator, and the Market Operator will respect those limits in its market optimization in order to commit and award resources to serve the expected load. In real-time, Bonneville will communicate any changes to ATC to the market, and market flows will continue to be able to use any real-time, unscheduled transmission capability on the Bonneville system.

Markets+ permits transmission customers to "opt-out"¹⁶⁵ their transmission rights according to the market rules, which includes no more than once per month and timely communication to the market operator. Informed by stakeholder input, Markets+ has developed a process for the opt-out communication from the TSP/BA to the MO.¹⁶⁶ Furthermore, the frequency of the opt-out communication was set to align with the TSRs congestion rent eligibility verification timeline. The "opt-out" of transmission rights removes that capacity entirely from reflection in the market and potentially any market settlement implications. However, by doing so, the transmission customer will forego the potential congestion rent revenue on the contracted paths if those paths become binding, as well as use of the market to help meet the schedule. The market rules and associated procedures for transmission opt-outs were set to provide an equitable and timely process for Market Participants that may need to opt-out transmission but to also address market power concerns on transmission usage. While Bonneville believes the current design mitigates any concerns with market power related to transmission usage, the Market Monitoring Unit (MMU) will monitor for transmission withholding by market participants that would violate the Markets+ Tariff.¹⁶⁷ Bonneville transmission contract holders that want to participate in another market (e.g., EDAM) may want to "opt-out" transmission from Markets+ so that generation in that market can be optimized across that transmission. Any additional requirements Bonneville places on transmission opt-outs would be determined in a future Tariff proceeding and/or business practice process.

Note that opting-out transmission is not required in order to (a) self-schedule or (b) individually transact outside of the Markets+ footprint. First, for self-schedules, the market optimization still respects generation self-scheduled within the market footprint. If a generator self-schedules, it consumes a portion of market-available transmission capacity, lowering the amount of transmission across which the market can optimize. This transmission capacity is still "in" the market and the transmission rights holder is still eligible for congestion rent allocation. Second, for transactions that cross the boundary of the Markets+ footprint, those transactions can be established within the

¹⁶³ Bonneville Power Administration, BPA's Public Engagement for Establishing a Policy Direction on Potential Day Ahead Market (DAM) Participation - Workshop 8 presentation (July 18, 2004), available at <https://www.bpa.gov/-/media/Aep/projects/day-ahead-market/2024/dam-workshop-8-presentation.pdf>.

¹⁶⁴ Service Flow Constraints are intended to represent a commercial constraint that manages market flows attributed to the market, not total flow expressed as a mega-watt (MW) value.

¹⁶⁵ SPP Markets+ Tariff, Attach. D § 1.2 (Obligation to Communicate Markets+ Transmission Capacity Availability Changes).

¹⁶⁶ Markets+ TSPs/BAs will need to develop their own opt-out process with its transmission customers that will ultimately feed into the Markets+ opt-out process. SPP Markets+ Protocol, 8.2.2 Markets+ Transmission Capacity Opt-Outs and Exhibit 8-2: Transmission Opt-Out and Congestion Rent Process Timeline.

¹⁶⁷ SPP Markets+ Tariff, Attach. C § 4.5 (Monitoring for Potential Transmission Market Power Activities)

market using an e-tag.¹⁶⁸ The market will incorporate the additional load obligation (for an export) or generation injection (for an import) within the optimization. Markets+ also allows for price-sensitive bidding at the market footprint in the day-ahead optimization, which requires an e-tag as well.

As the region moves towards participation in a day-ahead market, Bonneville understands that utilities, which may also be Bonneville transmission contract holders, are making their own independent market participation decisions and may want to use their Bonneville transmission rights in those markets. As a result, regardless of Bonneville's decision to join a day-ahead market, Bonneville may need to reflect tariff revisions and/or business practice updates to clarify the requirements for transmission customers to use their transmission rights for their respective market participation.

Bonneville will need to address necessary tariff changes for implementation. Bonneville will discuss potential tariff changes through the tariff process. Bonneville may also need to update its business practices for implementation and will do so through the established business practice process.

6.8.1. Transmission Product Availability

As discussed previously, Bonneville does not expect the general transmission products or terms and conditions to change due to Bonneville joining Markets+. However, joining Markets+ will impact the reservation and scheduling timelines of its short-term products, specifically, the hourly firm, hourly non-firm, and non-firm secondary products. Currently, Bonneville's hourly firm transmission window opens at 9 a.m. Pacific Time of the WECC preschedule day, and non-firm window for hourly and secondary products opens at 10 a.m. of the WECC preschedule day.¹⁶⁹ These transmission windows will need to be evaluated because the availability of these short-term products will need to conform to the day-ahead market timelines for the day-ahead (e.g., 10 a.m. deadline for the day-ahead market clearing process to start and initial RUC) and real-time horizons (e.g., intra-day RUC and T-30 for each operating hour), in order to afford customers enough time to buy transmission and meet market deadlines. Transmission customers in WECC are accustomed to navigating TSP timing windows for reserving transmission, not just Bonneville's, which vary and may be set in different time zones. Understanding the updated TSP timing windows for reserving transmission for day-ahead markets will be another consideration to navigate in the near future.

In addition, participating TSPs are required to pause processing of TSRs in the queue for the next operating day during the day-ahead market clearing process (approximately from 10 a.m. to 1:30 p.m. Pacific Time on day-ahead) so the market optimization has a static set of transmission constraints to develop the market solutions. While the queue is paused, transmission customers will have the ability to submit TSRs but those TSRs will remain in the queue in queue order. Once the market operator posts the awards associated with the market solutions and the TSPs have accounted for any incremental transmission used by the market, TSPs will resume processing TSRs in the queue.

As noted above, Bonneville understands that it will have transmission customers that may wish to use their Bonneville transmission rights for transactions/schedules that source or sink outside the BAA or for wheeling across the BAA, including for optimization in another market (e.g., EDAM). Bonneville will need to address how it will make its transmission available for use in other markets, as well as implementation of the reservation timelines in a future tariff proceeding and, as necessary, through the business practice process.

¹⁶⁸ E-tags are used to schedule power transactions that include who is supplying the power, how much power (expressed as MWs), timeframe, purchasing/selling entities involved, BAAs involved, the transmission paths, and who is receiving the power.

¹⁶⁹ Bonneville Power Administration, Requesting Transmission Service Business Practice V.47 § C.1 (Jan. 22, 2024), available at <https://www.bpa.gov/-/media/Aep/transmission/business-practices/tbp/requesting-transmission-service-bp.pdf>.

6.8.2. Transmission Losses

As energy is physically delivered across a transmission system, there is a natural degradation or “loss” that occurs because of physical factors such as distance and the overall loading of transmission facilities. Transmission losses represent additional physical generation that is necessary to make up the difference between a scheduled amount of energy from a generator and what is “lost” on the way to serving a load. Bonneville currently requires transmission customers to either designate to return transmission losses in kind (e.g., with a physical delivery of energy concurrently) or settle them financially.

In joining the WEIM, Bonneville did not need to make significant adjustments to the provision of losses because the majority of losses still occurred outside of the market (associated with the base schedules submitted ahead of the market). However, for the WEIM, Bonneville elected the “donation model” of Transmission Rights by Interchange Rights Holders¹⁷⁰ to be used for WEIM transfers that source or sink in the Bonneville BAA. The donation of these transmission rights into WEIM does not eliminate the transmission loss obligation of the Interchange Rights Holders, yet to avoid “double-payment,” Bonneville exempted loss returns for WEIM transfers using Bonneville transmission during WEIM participation because the market accounts for losses associated with incremental market transfers within the optimization.

In Markets+, both the day-ahead and real-time optimizations procure sufficient energy to serve losses across the market footprint. Transmission losses for both the day-ahead awards and the incremental real-time dispatches are settled financially by the market and reflected in the LMP. Bonneville will discuss with stakeholders the extent to which Markets+ may lead to changes in Bonneville’s current policies regarding transmission losses. Specifically, Bonneville will need to focus on two areas: 1) transmission that is not available to the market, and 2) transactions/schedules that use Bonneville transmission but source or sink outside the Markets+ footprint. Bonneville will address these details in applicable rates, tariff or business practice proceedings.

7. NEPA & Environmental Obligations

Consistent with NEPA, 42 U.S.C. § 4321 et seq., Bonneville is in the process of assessing the potential environmental effects that could result from the proposed participation in a day-ahead market. Bonneville believes this proposal appears to be the type of action typically excluded from further NEPA review pursuant to U.S. Department of Energy NEPA regulations, which apply to Bonneville. However, Bonneville will consider all public comments concerning NEPA compliance and/or potential environmental effects of the proposal that Bonneville received during the public discussions for this proposal.

8. Tribal Obligations

The Day-Ahead Market Policy does not impact tribal treaty rights or resources. First, the Policy is a decision on a policy direction, it is not a binding implementation decision to join Markets+. Any decision to join a day-ahead market will be made after further consideration. Second, any future DAM participation will not change Bonneville’s ability to meet obligations under existing laws and contracts, including FCRPS operations, river management, or fish and wildlife mitigation. As discussed in section 6.1.1, Bonneville can communicate various operational constraints for its generators as part of its market offers in order to meet both power and non-power obligations, and will continue to prioritize meeting all obligations. Therefore, this Policy does not impact Bonneville’s tribal treaty or general trust responsibilities.

9. Conclusion and Next Steps

The preceding Day-Ahead Market Policy represents an extensive analysis of the options available to Bonneville in

¹⁷⁰ Bonneville Power Administration, Energy Imbalance Market (EIM) Business Practice V.5 § J.

response to the developments of day-ahead markets in the West. Bonneville examined the market designs of both EDAM and Markets+ with a particular focus on the elements pertaining to governance and stakeholder process; RA and resource sufficiency; price formation and market power mitigation; transmission and congestion rent; and GHG accounting. Additionally, Bonneville has carefully considered the operational complexities, implementation challenges, and potential for sunk costs presented by each market option. The results of this analysis have been weighed against each of Bonneville's day-ahead market participation principles. Throughout this analysis, Bonneville has held a series of 11 public workshops to provide transparency into Bonneville's evaluation, responses to comments received, day-ahead market offerings, Pathways, and impacts to various aspects of Bonneville's business and products.

Governance has specifically been a central factor in Bonneville's evaluation. Markets+ successfully developed and implemented a governance structure that met Bonneville's criteria. In the meantime, Pathways performed significant work to develop recommendations to improve independence of the governance of the CAISO-run WEIM and EDAM markets. To date, its recommendations have resulted in an approved future transition to primary authority for the independent WEM Governing Body. Several entities have requested that Bonneville delay its day-ahead market decision until the end of 2025 to allow more time for the California legislature to act on proposed legislation to move the Pathways vision forward and for the governance model to continue to evolve towards full independence. While Bonneville applauds the considerable work done by Pathways, its recommendations do not enable the level of independence that is offered by Markets+. The legislation that has been introduced would confirm this limited scope of independence. For that reason, Bonneville does not see benefit in waiting for California's legislative consideration.

The Pathways Step 2 proposal suggested future considerations to expand the independence, and the market services offered. Those subsequent steps to greater independence would be incremental and subject to further studies and likely further legislative authorization. Ultimately, Bonneville prefers the stakeholder-driven governance structure of Markets+. Bonneville contends that the Markets+ development has resulted in a superior market design that is available today and believes it will remain a durable, equitable form of governance in the future.

Bonneville's analysis presented complex results regarding each day-ahead market option, including the status quo. The PCM studies showed a wide range of potential economic outcomes, including meaningful trends that joining EDAM could yield a greater financial benefit for Bonneville and that joining Markets+ has potential for significant monetary benefits under multiple scenarios. It is important to note that these results are not due to differences in market design but are driven from higher prices that come with being in a market with California and the connectivity offered by the current expected EDAM footprint. In almost every scenario, this potential greater monetary benefit was dependent on the assumption that Bonneville would continue to enjoy surplus generation, which adds uncertainty to the results as Bonneville's load and generation forecasts demonstrate a potential erosion of its surplus generation over time. As demonstrated, the benefits in the expected Markets+ footprint improved as hurdle rates were reduced, closing the gap between EDAM and Markets+ benefits and resulting in benefits above BAU.

Additionally, PCMs do not account for market design features, such as congestion rent, market power mitigation, and price formation, that can significantly impact monetary benefits realized from a day-ahead market. These design features are discussed in detail in this analysis and Bonneville believes the Markets+ design is likely to provide economic benefits to Bonneville and our customers through these features that at least partially offset the EDAM benefits estimated in the PCM studies. These design features in Markets+ were all constructed via an inclusive stakeholder process that should result in these market design features accounting for unique needs of market participants, and Bonneville is confident that the Markets+ stakeholder process will be responsive to requests to revisit these design elements if unexpected or unsatisfactory results are realized once the market is live. Bonneville has determined that the trends toward greater potential monetary benefits under the previously discussed assumptions and caveats in EDAM and in the short term for status quo do not outweigh the strategic benefits and

superior market design presented with Markets+.

The option of Bonneville remaining only in the WEIM while its neighbors join day-ahead markets was an option that Bonneville carefully considered, and one that the PCM results showed could bring significant monetary benefit. While Bonneville agrees this option shows short term appeal, Bonneville continues to have significant concerns about the long-term viability of this option due to the operational and economic risks, such as reduced liquidity in the bilateral market, that accompany this option. Remaining in WEIM would likely foreclose the option to join Markets+, leaving EDAM as the only day-ahead market option for Bonneville should it choose to pursue day-ahead participation in the future. Because the Pathways Step 2 proposal does not achieve desired independence, and legislation remains speculative, this option carries significant strategic risk. Other important elements that Bonneville examined in this process are the market seams and the potential operational complexities that will be present with multiple markets in the Pacific Northwest. Bonneville acknowledges that a single market in the Northwest would be operationally simpler, but the decisions of Bonneville's neighboring BAAs suggest that two markets are likely to operate in the Pacific Northwest. The presence of these challenges should not prevent Bonneville from joining a market with superior design and independence. Bonneville places great importance on its operational and reliability responsibilities in the region and stands ready to work with the entities in EDAM and within the region to collaboratively resolve these jointly owned issues.

Throughout this evaluation process, Bonneville has experienced the powerful impact of competition in motivating both SPP and CAISO to significantly improve market offerings in order to attract participants. Without this competition, Bonneville believes many of the creative market design solutions benefitting consumers that both market operators are pursuing may have never materialized. Bonneville also believes many of the changes contemplated and implemented in the CAISO governance and stakeholder processes and the recent urgency with which they have been pursued are a direct result of competition from another market operator. These CAISO initiatives are resulting in an improved market for entities that have or may choose EDAM participation. The continuation of this competition benefits Bonneville, its customers and all consumers in the west regardless of market participation choices by maintaining pressure on market operators to continue innovating and improving.

After thorough evaluation, analysis, and weighing of its participation principles, as well as the governance, market design, and strategic benefits presented by Markets+, Bonneville has concluded that its participation in Markets+ is the best long-term strategic direction for Bonneville, its customers, and the Northwest.

Bonneville would like to express profound appreciation for those who have engaged in the public process and provided insights to make this a robust, transparent, and effective evaluation of its potential participation in a day-ahead market. Bonneville looks forward to ongoing public review and input as implementation details are developed. Bonneville will be developing a stakeholder engagement plan to provide market design updates and technical implementation that will incorporate customer input. Bonneville will be utilizing the '6-step process' as a way to collaborate with customers on the policy issues through the tariff and rates proceedings.

Appendix A

Legal Assessment

1. Legal Authority to Join Markets+

Bonneville’s decision to join any market must comport with multiple grants of authority, including, but not limited to, power marketing, providing transmission service, and operating in a business-like manner. In exercising such authorities, the Administrator must balance his ability to meet multiple statutory obligations, such as providing preference and priority in the sale of power when there are conflicting or competing requests, making firm power sales under section 5(b) of the Northwest Power Act, providing transmission service and operating the transmission system, setting rates sufficient to repay the federal investment, and fulfilling environment, fish and wildlife obligations. This legal assessment describes how Bonneville could meet these obligations while participating in Markets+. At a high-level, Bonneville would join Markets+ by agreeing to a set of contracts incorporating a day-ahead market tariff.

Bonneville would exercise its contracting authority under section 2(f) of the Bonneville Project Act¹⁷¹ to agree to a day-ahead market tariff. This would be similar to actions Bonneville has taken to participate in WEIM and WRAP.¹⁷² Similar to the WEIM and WRAP agreements, and like any contract with a market operator implementing a day-ahead market subject to an applicable tariff, an agreement to participate in a day-ahead market must expressly acknowledge and not infringe upon Bonneville’s authority to meet its statutory obligations and contractual requirements. Based on the day-ahead market tariff offerings to date, Bonneville has not identified legal barriers to satisfying its statutory obligations while participating in a day-ahead market.

Bonneville has the business flexibility to participate in a day-ahead market.

Since its inception, Congress has imbued Bonneville with broad statutory authority to market the power produced by federal hydropower generating projects. In the Bonneville Project Act of 1937, Congress granted Bonneville broad contracting authority for the specific purpose of allowing Bonneville to operate like a business in the marketing of federal power.¹⁷³ As the designated “marketing agent” for all electric power generated by the Federal Columbia River Power System,¹⁷⁴ Bonneville’s statutes are unique with repeated focus on the business-related aspects of the agency’s authority.

Both Congress and the courts have reaffirmed Bonneville’s authority to operate in a businesslike manner. As summarized in a 1977 Senate Report:

[The] legislative history [of the statutes governing Bonneville’s operations] reflects a congressional recognition of the significant role played by [Bonneville] in the Pacific Northwest, and an effort to enable this organization to operate in a businesslike fashion and to free it from the requirements and restrictions ordinarily applicable to the conduct of Government business. The transfer of the functions of [Bonneville] from the Department

¹⁷¹ 16 U.S.C. § 832a(f).

¹⁷² Bonneville Power Administration, Energy Imbalance Market Policy, Administrator’s Record of Decision at 54-56 (Sept. 2019) (WEIM Policy ROD), *available at* <https://www.bpa.gov/-/media/Aep/projects/energy-imbalance-market/rod-20190926-energy-imbalance-market-policy.pdf>; Bonneville Power Administration, Bonneville’s decision to participate in the Western Resource Adequacy Program Phase 3B (Dec. 16, 2022), *available at* <https://www.bpa.gov/-/media/Aep/projects/resource-adequacy/wrap-final-closeout-letter.pdf>.

¹⁷³ Bonneville Project Act, 16 U.S.C. § 832a(f); *see* S. Rep. No. 79-469, at 13 (1945) (“[BPA] operates a business enterprise . . .”) (letter from Interior Secretary Ickes).

¹⁷⁴ Transmission System Act of 1974 § 8, 16 U.S.C. § 838f.

of the Interior to the Department of Energy is not intended to diminish in any way the authority or flexibility which is a requisite to the efficient management of a utility business.¹⁷⁵

The ability of Bonneville to adapt to the ever-changing landscape of the wholesale electric power industry like a business is particularly important because the Administrator must implement many, and often competing, statutory directives.¹⁷⁶ Similarly, the U.S. Court of Appeals for the Ninth Circuit has noted that “[The Administrator] must continue to run [Bonneville] like a business on a sound financial basis, enabling it to repay its debt to the federal treasury in a timely fashion, while discharging costly new public duties assumed after the Northwest Power Act’s passage.”¹⁷⁷

In 1995, Bonneville adopted a Business Plan with a market-driven direction and a goal to be a more active participant in the competitive market for power, transmission, and energy services.¹⁷⁸ As stated in the 1995 Business Plan Record of Decision, Bonneville’s objective is to use its success in markets to ensure the financial strength necessary to better produce the public benefits that Bonneville affords to the region.¹⁷⁹ The market-driven approach is designed to increase the value of Bonneville’s business and generate expanded benefits to share with customers and constituents-including energy conservation and fish and wildlife mitigation.¹⁸⁰ By evaluating potential participation in a day-ahead market, Bonneville is continuing its long-standing business strategy to pursue options that could produce value for Bonneville’s customers and the region.

This Policy discusses how Bonneville and the region as a whole are experiencing significant and unprecedented changes in the industry. Faced with competitive drivers and new regulatory requirements, electric utilities are devoting significant resources to develop and transition to market-based solutions that aim to reduce inefficiencies, improve power and transmission system reliability, lower production costs, and bolster resource adequacy, among other things. Bonneville and other utilities’ participation in the Western Energy Imbalance Market are an example of one such development. These new competitive drivers are creating opportunities for Bonneville to modernize its business to preserve and enhance the value Bonneville provides to its customers pursuant to its statutory mission.

As Bonneville evaluates potential participation in a day-ahead market, some of its key objectives rooted in statute are to ensure an adequate, efficient, economical, and reliable power supply, and to encourage the widest possible diversified use of electric power at the lowest possible rates to consumers consistent with sound business principles. Therefore, Bonneville continues to assess whether participation would provide value for customers in terms of greater efficiency, lower costs, and increased reliability.¹⁸¹

2. Bonneville would fulfill its preference obligations and Northwest Power Act Section 5(b) firm power sales obligations while participating in a day-ahead market.

Bonneville’s authority to market federal power is included in several statutes: the Bonneville Project Act

¹⁷⁵ S. Rep. No. 95-164, at 30 (1977), reprinted in 1977 U.S.C.C.A.N. 854, 884.

¹⁷⁶ *Ass’n of Pub. Agency Customers v. Bonneville Power Admin.*, 126 F.3d 1158, 1170-71 (9th Cir. 1997).

¹⁷⁷ *Id.*

¹⁷⁸ Bonneville Power Administration, Business Plan Record of Decision (Aug. 15, 1995), available at <https://www.bpa.gov/-/media/Aep/about/publications/records-of-decision/1995-rod/rod-19950815-business-plan-final-environmental-impact-statement.pdf>.

¹⁷⁹ *Id.* at 1.

¹⁸⁰ *Id.* at 11.

¹⁸¹ Bonneville Power Administration, Staff Recommendation on Day-Ahead Market Participation at 2-3 (Apr. 2024), available at <https://www.bpa.gov/-/media/Aep/projects/day-ahead-market/2024/02-day-ahead-market-attachment-1-staff-recommendation.pdf>.

of 1937, the Flood Control Act of 1944, the Pacific Northwest Consumer Power Preference Act of 1964, the Federal Columbia River Transmission System Act of 1974, and the Pacific Northwest Power Planning and Conservation Act of 1980. Collectively, these statutes form the basis for Bonneville's broad authority to market power. For Bonneville to participate in Markets+, it must market power consistent with these statutory authorities.

Bonneville recognizes that many stakeholders have requested explanations of how Bonneville will meet obligations in these statutes to provide public bodies and cooperatives preference and priority to federal power, and to offer contracts for the sale of electric power under section 5(b) of the Northwest Power Act, considering the paradigm shift that a day-ahead market would represent. As explained below, Bonneville will continue to meet its preference and section 5(b) obligations included in these authorities if it participates in a day-ahead market.

a. Bonneville must provide preference in sales of power at all times in the event of competing or conflicting applications for power.

Bonneville will continue to provide preference in the sale of power to public bodies and cooperatives in the event of competing applications. Bonneville would continue to offer long-term power sales contracts to 5(b) customers and would incorporate the day-ahead market dispatch framework into the contract terms and rates for such sales. Section 4(a) of the Bonneville Project Act of 1937 specifies, “[i]n order to insure that the facilities for the generation of electric energy at the Bonneville project shall be operated for the benefit of the general public, and particularly of domestic and rural customers, the administrator shall at all times, in disposing of electric energy generated at said project, give preference and priority to public bodies and cooperatives.”¹⁸² Section 4(b) further explains, “in the event that . . . there shall be conflicting or competing applications for an allocation of electric energy between any public body or cooperative on the one hand and a private agency of any character on the other, the application of such public body or cooperative shall be granted.”¹⁸³ The Flood Control Act of 1944 similarly states that “[p]reference in the sale of such power and energy shall be given to public bodies and cooperatives.”¹⁸⁴ Thus, Bonneville's earliest legislation established the foundational principle that Bonneville shall afford preference to public bodies and cooperatives in the event of competing or conflicting requests for power. Bonneville understands that providing preference in the event of competing applications is a fundamental component of its power marketing obligation that it will continue to meet if it chooses to participate in Markets+ for the benefit of its customers.

Section 5(a) of the Northwest Power Act reaffirms the preference and priority provisions from Bonneville Project Act by stating, “[a]ll power sales under this chapter shall be subject at all times to the preference and priority provisions of the Bonneville Project Act of 1937”¹⁸⁵ The Northwest Power Act was enacted to resolve regional power customer fears about an impending allocation of low-cost Federal power. The House Report of the Commerce Committee on the Northwest Power Act emphasized that sales by the Administrator would be subject to existing preference provisions:

The purpose of this provision is clear. The Committee wants to ensure that all preference customer contract requirements will continue to have a priority over sale to other customers

¹⁸² 16 U.S.C. § 832c(a).

¹⁸³ 16 U.S.C. § 832c(b); *see also Aluminum Co. of Am. v. Cent. Lincoln People's Util. Dist.*, 467 U.S. 380, 393 (1984) (“[T]he preference system merely determines the priority of different customers when the Administrator receives ‘conflicting or competing’ applications for power that the Administrator is authorized to allocate administratively.” (citing section 4(b) of the Bonneville Project Act)).

¹⁸⁴ 16 U.S.C. § 825s.

¹⁸⁵ 16 U.S.C. § 839c(a).

and other sales would be, in effect, subordinate to preference provisions of the Bonneville Project Act, including the 5-year withdrawal features for contracts with non-preference customers and the 20-year limitation on the terms of the contract.¹⁸⁶

Bonneville finds that it will be able to continue to satisfy preference when there is a competing or conflicting application for power in a day-ahead market. As described above, in a day-ahead market context, Bonneville would continue to make long-term forward sales of power and would apply preference if faced with a limited supply of power. After the day-ahead market clears, any out-of-market requests for electric power from Bonneville are likely to fall within the context of a surplus sale. Bonneville would continue to meet its preference obligations for both long-term sales and surplus sales as described below.

b. Bonneville is authorized to acquire resources to meet all eligible customer requests for electric power under section 5(b) of the Northwest Power Act.

Bonneville's acquisition authority generally ensures that Bonneville can acquire to meet the needs of all customers requesting contracts for electric power and thereby avoid a preference allocation among competing or conflicting requests for power. Historically, there was no need for Bonneville to apply preference because Bonneville had an abundance of power. However, in the 1970s, projections showed that because of increased power demand, the Administrator would be required to apply preference and allocate the limited amount of federal power. Upon expiration of the power sales contracts with non-preference customers, the Administrator would no longer be able to sell power to non-preference entities because the preference clauses would obligate him to allocate the limited supply to public bodies and cooperatives. Congress drafted the Northwest Power Act to prevent the need for an allocation of power.¹⁸⁷ The Act solved the pending allocation and reduces the potential application of preference in the future by providing the Administrator with resource acquisition authority to meet his sales obligation.

Section 5(b)(1) of the Northwest Power Act provides,

Whenever requested, the Administrator shall offer to sell to each requesting public body and cooperative entitled to preference and priority under the Bonneville Project Act of 1937 . . . and to each requesting investor-owned utility electric power to meet the firm power load of such public body, cooperative or investor-owned utility in the Region to the extent that such firm power load exceeds [customer resources].¹⁸⁸

Section 5(b) thus establishes the Administrator's obligation to offer a contract for the sale of electric power to meet the firm power loads of any requesting regional public body, cooperative, or investor-owned utility in excess of non-federal resources used by the customer to serve such load. The Act not only requires the Administrator to offer a contract for the sale of electric power to all eligible requesting customers but also directed the Administrator to offer new power sales contracts to then-existing direct service industry customers.

To implement the Act in a timely matter, Congress deemed the Administrator to have sufficient resources and, most importantly, granted the Administrator authority to acquire resources to meet Bonneville's long-term power supply obligations. In sections 6(b), (c), and (d) of the Northwest Power Act, Congress granted

¹⁸⁶ H.R. Rep. No. 97-976, Pt. I, at 34 (1980).

¹⁸⁷ As the Supreme Court has explained, "Congress moved to avert what appeared to be an emerging customer struggle for [Bonneville] power by enacting the [Northwest Power Act]." *Aluminum Co. of Am.*, 467 U.S. at 383. And as Congressman Swift remarked, "[t]he basic concept of this bill is simple: It permits BPA to avoid the need for an administrative reallocation of power by giving BPA the means to reduce loads and to acquire resources so that it should be able to meet the needs of all classes of customers This is a bill to solve a power allocation problem" 126 Cong. Rec. H27818 (daily ed. Sept. 29, 1980) (remarks of Rep. Swift).

¹⁸⁸ 16 U.S.C. § 839c(b).

Bonneville the authority to acquire resources to meet his long-term power supply obligations.¹⁸⁹ It is important to note that while section 5(b) requires the Administrator to supply the power requirements of all requesting public and investor-owned utility customers and to acquire resources when necessary, Congress also provided protections for preference customer rates when establishing rates pursuant to section 7(b).¹⁹⁰

Importantly, section 5(b) contracts are not a response to “competing or conflicting” requests for power that would require an allocation of electric energy. The section 5(b) sales obligation operates in conjunction with long term loads and resource planning and the section 6 resource acquisition authority so that, in general, Bonneville does not need to allocate power among conflicting or competing applications. When a customer has a long-term power sales contract, they receive power under that contract and preference is not triggered.

While the obligation remains of paramount importance, preference only triggers if Bonneville is unable to acquire resources to satisfy its 5(b) obligations due to an insufficiency of resources or if Bonneville is offering to sell surplus electric power. The insufficiency and surplus scenarios are discussed in the following two sections.

c. Bonneville must apply preference in an allocation scenario.

In a scenario where Bonneville is faced with a limited supply of power in the planning horizon, preference would apply. In general, section 6 of the Northwest Power Act provides Bonneville with acquisition authority designed to ensure he can meet all requests for power. Section 11(b)(6) of the Transmission System Act also provides Bonneville with the authority to purchase electric power on a short-term basis to meet temporary deficiencies in power it is obligated to supply.¹⁹¹

Bonneville’s ability to acquire power to meet its supply obligations generally avoids Bonneville having a limited amount of power that must be allocated through the operation of preference. Northwest Power Act section 5(b)(5) requires the Administrator to provide contractual mechanisms to apply preference in the unlikely event that Bonneville cannot acquire resources to meet its power supply obligations.¹⁹² If the Administrator “cannot be assured on a planning basis of acquiring sufficient resources to meet such loads during a specified period of insufficiency” he is obligated to apply preference and allocate electric energy among customers in accordance with the section 5(b)(6) allocation provisions.¹⁹³

If Bonneville were to determine that it cannot be assured on a planning basis to meet its long-term firm power sales, Bonneville would allocate power based upon the insufficiency and allocation methodology.¹⁹⁴

Additionally, Bonneville’s participation in a day-ahead market is likely to substantially mitigate the risk of an insufficiency. Bonneville will maintain its existing Resource Program, which incorporates guidance from Northwest Power and Conservation Council’s Power Plan; continue to plan its resources on an annual, monthly, daily, and real-time basis to assure a firm power supply to meet its firm power sales obligations; and participate in WRAP. In the long term, day-ahead markets should lead to improved regional resource planning. Markets+ requires each participant, including Bonneville, to demonstrate a commitment that it has sufficient resources available to meet its forecast load obligations in the planning horizon by participating in the WRAP. Based on Bonneville’s continued efforts and the benefits that coordination

¹⁸⁹ 16 U.S.C. § 839d(b)-(d).

¹⁹⁰ 16 U.S.C. § 839e(a)-(b).

¹⁹¹ 16 U.S.C. § 838i(b)(6).

¹⁹² 16 U.S.C. § 839c(b)(5).

¹⁹³ *Id.*; 16 U.S.C. § 839c(b)(6).

¹⁹⁴ See Notice of Publication of the Insufficiency and Allocations Exhibit for the Power Sales Contract, 61 Fed. Reg 11,389 (Mar. 20, 1996).

through a market will bring, there will be an even lower chance that Bonneville would be required to allocate power based on a projected insufficiency on a planning basis.

d. Bonneville will apply preference for competing and conflicting applications for surplus power.

The most common application of statutory preference is when Bonneville offers to make a surplus power sale. The Bonneville Project Act of 1937¹⁹⁵ and the Pacific Northwest Consumer Power Preference Act of 1964¹⁹⁶ specify the application of statutory preference when Bonneville markets surplus power. The Regional Preference Act specifies that, in the event of competing applications for available surplus power, and terms and conditions are mutually agreed upon, Bonneville will meet customer requests in the following order: 1) Pacific Northwest public utilities, 2) Pacific Northwest investor-owned utilities and direct-service industrial customers, and 3) Southwest public utilities. Thereafter, if additional power is available, Bonneville may also make surplus sales to non-preference customers.

In the Western Energy Imbalance Market Policy Record of Decision, Bonneville explained the specific mechanics of the notice of surplus power. Consistent with that analysis, in a day-ahead market, Bonneville intends to continue the regional notice format the agency has used for over 20 years.¹⁹⁷ Since the advent of modern markets, Bonneville has provided notice to its preference customers regarding the availability of short-term surplus power using a combination of: (1) annual letters providing notice of surplus availability and how regional customers may exercise their rights; (2) product specific letters/emails when Bonneville is preparing to sell a new type of product to a non-preference customer; and (3) a standing daily notification on Bonneville's website regarding the availability of surplus power and instructing regional customers on how to obtain it if they are interested. Bonneville is unaware of any instance during the past 20 years where regional preference customers took issue with the format of Bonneville's notice requirements. This format has been an efficient and effective way for Bonneville to participate in the short-term market while also notifying regional customers that Bonneville may have surplus power available for sale on a rolling basis.¹⁹⁸

When Bonneville began to participate in the Western Energy Imbalance Market, it updated its daily standing notice to specify that, if surplus remains available prior to the market run, Bonneville may bid such surplus power into the market at its discretion. In a day-ahead market, Bonneville would follow the same approach. The agency would continue to provide public preference and Pacific Northwest regional preference to requests for surplus power before and after the day-ahead market run. Bonneville would continue to welcome customer inquiries regarding potential purchases of surplus power before and after the day-ahead market submission timeframe.

Similarly, Bonneville's participation in a day-ahead market will not impact its surplus sales approach. Bonneville will continue to market surplus power when available, prior to the day-ahead market generation and load bid submission window, and thereafter prior to the real-time market bid submission window. The day-ahead market resource schedule output does not ultimately determine real-time dispatch, the real-time market bid submission window allows for Bonneville to make additional sales if surplus power remains available. Bonneville will continue to meet its regional preference obligations when marketing uncommitted surplus power.

For the reasons described above, Bonneville's legal assessment is that it can participate in a day-ahead market consistent with its preference obligations, 5(b) firm power sales obligation, obligations to allocate power consistent with preference in the event of insufficiency, and obligations to provide preference when

¹⁹⁵ 16 U.S.C. § 832 *et seq.*

¹⁹⁶ 16 U.S.C. § 837 *et seq.*

¹⁹⁷ WEIM Policy ROD at 62.

¹⁹⁸ *Id.*

making surplus sales.

3. Day-ahead market participation would be akin to an interregional exchange of power.

Since the enactment of the Bonneville Project in 1937 through the passage of the Pacific Northwest Electric Power Planning and Conservation Act in 1981, Congress contemplated and included within the scope of the Administrator's authorities the authority to interconnect with power systems both within and outside the Pacific Northwest region and leverage these interconnections to make mutually beneficial interregional exchanges. For example, section 2(b) of the Bonneville Project provides:

In order to encourage the widest possible use of all electric energy that can be generated and marketed and to provide reasonable outlets therefor, and to prevent the monopolization thereof by limited groups, the administrator is authorized and directed to provide, construct, operate, maintain, and improve such electric transmission lines and substations, and facilities and structures appurtenant thereto, as he finds necessary, desirable, or appropriate for the purpose of transmitting electric energy, available for sale, from the Bonneville project to existing and potential markets, and, *for the purpose of interchange of electric energy, to interconnect the Bonneville project with other Federal project and public owned power systems* constructed on or after August 20, 1937.¹⁹⁹

The Northwest Power Act also includes provisions promoting interregional exchanges. Section 6(l)(1) provides:

The Administrator is authorized and directed to investigate opportunities for adding to the region's resources or reducing the region's power costs through the accelerated or cooperative development of resources located outside the States of Idaho, Montana, Oregon, and Washington if such resources are renewable resources, and are now or in the future planned or considered for eventual development by nonregional agencies or authorities that will or would own, sponsor, or otherwise develop them.²⁰⁰

Section 6(l)(2) further provides:

The Administrator is authorized and directed to investigate periodically opportunities for mutually beneficial interregional exchanges of electric power that reduce the need for additional generation or generating capacity in the Pacific Northwest and the regions with which such exchanges may occur.²⁰¹

Congress understood that interregional transmission interties between the Pacific Northwest and adjoining regions, such as the Pacific Northwest Pacific Southwest Intertie, offer substantial benefits. At the time of the enactment of the Northwest Power Act, existing transactions reduced the need for new generating capacity, helped provide more reliable service to load, reduced the need to rely on fossil fueled resources, and reduced the costs of electricity. In a June 1981 report on Interregional Resource Potentials, Bonneville committed to continuing to work with entities in the region and adjoining regions to optimize the use of existing generating facilities and reduce the need for new generating facilities through mutually beneficial exchanges and other transactions.

Bonneville has a longstanding definition of interchange energy in the power marketing context.²⁰² Interchange energy means energy received by one utility system from another, usually in exchange for

¹⁹⁹ 16 U.S.C. § 832a(b) (emphasis added).

²⁰⁰ 16 U.S.C. § 839d(l)(1).

²⁰¹ 16 U.S.C. § 839d(l)(2).

²⁰² See Bonneville Definitions (1993).

energy delivered to the other utility at another time or place. It is distinguished from a direct purchase or sale, although accumulated energy balances are sometimes settled in cash. Through interchange and interconnection, Bonneville has been able to enter into power-for-power exchanges, including some with payments of money incidental to the power that were justified as a suitable exchange term. Indeed, exchanges need not be simultaneous and the places where an exchange occurs may vary.

A day-ahead market will operate similar to an exchange of power because all market participants must bring sufficient resources to the market to serve their loads, which is designed to prevent participants from leaning on other participants. Rather than a bilateral exchange of power, power exchanged in the market will flow among the participants to make the most economical use of the transmission system. Thus, the power available under a day-ahead market is in effect exchanged between and among the participants resulting in all participants maintaining their load and resource balance. Here, Bonneville's participation in the interregional Markets+ day-ahead market falls within the scope of the section 6(l) directives to investigate such markets and the resources exchanged therein, including to increase supplies of electric power produced by renewable resources.

4. Bonneville policies will ensure that section 5(b) customers receive power with environmental attributes reflecting the system resource mix.

Bonneville's preference customers have requested acknowledgement of the inherent value of the low-carbon resources from which Bonneville supplies power. Bonneville committed in its Provider of Choice Policy to convey the environmental attributes of the power sold, including emissions and any Renewable Energy Certificates commensurate with a customer's firm power purchase amount and rate elections. Bonneville believes it is reasonable to conclude that these non-power characteristics should accompany Bonneville's physical sales of power. Bonneville's objective as an active participant in developing the day-ahead market GHGs framework designs has been to ensure that it can uphold its policy that non-power characteristics will accompany Bonneville's sales of power.

Bonneville markets power from the system mix of federal and non-federal resources, and this will not change in a day-ahead market. While some jurisdictions have concluded that environmental attributes are associated with power, such environmental attributes are defined through variously differing state laws and local regulations and are subject to change and are not applicable to Bonneville. Nevertheless, Bonneville believes a policy consideration regarding participation in a day-ahead market is whether the market rules support conveyance of environmental attributes associated with sales of power to Bonneville's public customers. Bonneville finds the Markets+ Tariff to meet its policy objectives notes that many of Bonneville's public power customers also support its greenhouse emissions accounting mechanisms. Bonneville will continue to work with its customers, and in the appropriate market design forums, as work on GHG accounting continues.

5. Bonneville would participate in a day-ahead market consistent with its authorities to provide transmission service and operate the transmission system.

Bonneville has broad authority under its governing statutes to set the terms and conditions of transmission service, as well as how to operate the system in order to provide transmission service and maintain reliability.²⁰³ While participating in Markets+, Bonneville will continue to offer transmission service and Ancillary and Control Area Services under its OATT, which ensures that Bonneville and its customers take transmission service on a comparable basis. Bonneville will also be able to make transmission available for

²⁰³ See *Cal. Energy Comm'n v. Bonneville Power Admin.*, 909 F.2d 1298, 1314 n.17 (9th Cir. 1990) (holding that the Administrator's authority to operate the transmission system "is broad, allowing the Administrator substantial discretion" and that "[t]his discretion is tempered only by the implied limitation that the Administrator's action not be inconsistent with other congressional decrees.").

market use, which is authorized under section 2(b) of the Bonneville Project Act.²⁰⁴

Joining a day-ahead market will require that transmission be made available for market use. Making transmission available for day-ahead market use falls within Bonneville's broad transmission authorities. Bonneville is monitoring day-ahead market policies to ensure benefits to transmission rights holders including through congestion rent policies, and to ensure compensation for any lost transmission sales through market transmission use charges. In addition, Bonneville will work through issues presented by entities holding transmission rights on the Bonneville system that want to participate in various day-ahead markets, as well as with Bonneville customers in other balancing authority areas that may be affected by a transmission provider's market participation.

6. Congress granted federal utilities authority to join transmission organizations.

In the Energy Policy Act of 2005 (EPAct '05), Congress provided authority for federal utilities, including power marketing administrations, to participate in transmission organizations, such as RTOs, consistent with their existing statutory authorities, obligations, and limitations.²⁰⁵ When considering EPAct '05, the House Committee on Energy and Commerce, Subcommittee on Energy and Air Quality discussed the economic dispatch associated with organized markets and its potential benefits for fostering competitive electric markets and ultimately reducing costs to the consumer.

By 2005, RTO and ISO market designs had matured significantly since deregulation formally began in 1996.²⁰⁶ RTOs had formed in many parts of the country and some included day-ahead and real-time energy markets based upon economic dispatch. Congress enacted the EPAct '05 with awareness of the context of evolving electricity markets, including Federal Energy Regulatory Commission Order No. 2000 regarding RTOs, which FERC Commissioner Bromwell explicitly discussed in her House committee testimony regarding the bill. Commissioner Bromwell explained that "RTOs that are fully independent of market participants can ensure non-discriminatory operation of the transmission facilities under their control. RTOs have FERC-approved market monitors, implement FERC-approved market mitigation plans, and conduct long-range planning all for the protection of customers. RTOs can perform economic dispatch over large geographic areas that will ensure the selection of least-cost generators. Finally, RTOs can offer organized markets and one-stop shopping that reduce transaction costs, provide transparent market rules and allow the opportunity for price discovery."²⁰⁷

Consistent with this sentiment, Bonneville views its EPAct '05 authority and Congress's understanding of organized markets as informative for its consideration of whether to participate in a day-ahead market. A day-ahead market is one element that is present across RTOs. In contrast to a full RTO, the proposed day-ahead market designs allow Bonneville to retain substantial control over its transmission assets and preserve its BAA responsibilities. Moreover, as the Supreme Court explained, "[t]he intention of Congress can be

²⁰⁴ See Bonneville Project Act, 16 U.S.C. § 832a(b) ("[T]o encourage the widest possible use of all electric energy that can be generated and marketed . . . the administrator is authorized and directed to provide, construct, operate, maintain, and improve such electric transmission lines . . . as he finds necessary, desirable, or appropriate for the purpose of transmitting electric energy . . . to existing and potential markets . . .").

²⁰⁵ 42 U.S.C. § 16431.

²⁰⁶ Order No. 888, *Promoting Wholesale Competition Through Open Access Non-discriminatory Transmission Services by Public Utilities; Recovery of Stranded Costs by Public Utilities and Transmitting Utilities*, 75 FERC ¶ 61,080 (1996); *Open Access Same-Time Information System and Standards of Conduct*, Order No. 889, FERC Stats. & Regs. ¶ 31,035 (1996), *order on reh'g*, Order No. 889-A, FERC Stats. & Regs. ¶ 31,049 (1997), *order on reh'g*, Order No. 889-B, 81 FERC ¶ 61,253 (1997), *order on reh'g*, Order No. 889-C, 82 FERC ¶ 61,046 (1998); Order No. 2000, *Regional Transmission Organizations*, 89 FERC ¶ 61,285 (Dec. 20, 1999).

²⁰⁷ *Comprehensive National Energy Policy: Hearings Before the Subcomm. on Energy and Air Quality of the Comm. On Energy and Commerce*, 108th Cong. 57 (Mar. 5, 2003) (Serial No. 108-7).

gleaned, at least in part, by reference to prior law, as Congress is presumed to be knowledgeable about existing law”²⁰⁸ Thus, while the development of a day-ahead market is not an RTO, it is reasonable to conclude that Congress contemplated federal utilities would be authorized to participate in subcomponents of an RTO, like a day-ahead market, as part and parcel of that express authority.

7. Bonneville participation in a day-ahead market must be effectuated through rates and tariff terms and conditions.

If Bonneville participates in Markets+, it will continue to establish its power and transmission rates in Northwest Power Act section 7(i) rate proceedings, and it will set the terms and conditions for transmission service in tariff proceedings.²⁰⁹ Under Section 7(a)(1) of the Northwest Power Act, the Administrator establishes “rates for the sale and disposition of electric energy and capacity and for the transmission of non-Federal power. Such rates shall be established . . . to recover . . . the cost associated with the acquisition, conservation, and transmission of electric power, including the amortization of the Federal investment . . . over a reasonable period of years and the other costs and expenses incurred by the Administrator”²¹⁰ Under section 7(a)(2), the Federal Energy Regulatory Commission reviews Bonneville’s proposed rates to ensure they are 1) sufficient to assure repayment of the Federal Columbia River Power System over a reasonable number of years after first meeting the Administrator’s other costs, 2) based upon the Administrator’s total system costs, and 3) insofar as transmission rates are concerned, equitably allocate the costs of the Federal transmission system between Federal and non-Federal power utilizing such system.²¹¹

In a day-ahead market, Bonneville’s rates must continue to be sufficient to recover total system costs including the Fish and Wildlife program, the Residential Exchange Program, amortization of existing debt, Columbia Generating Station financing, conservation, depreciation expenses, costs associated with achieving financial policy objectives, and costs associated with market participation. Bonneville’s rates must also equitably allocate the cost of the transmission system between federal and non-federal uses. Bonneville’s rates are based on forecasts and risk adjustment mechanisms respond holistically to actuals differing from forecast. Bonneville anticipates aggregate treatment of market benefits, which may vary based on products and services. In a section 7(i) rate proceeding, Bonneville would assess how to reflect the costs and benefits of market participation in rates, considering the interaction of any new mechanisms with existing policies. Participation in a day-ahead market would not change the Administrator’s obligation to set rates to recover total system costs.

In addition to rate updates, the agency would need to make changes to the terms and conditions of transmission service it provides to customers to enable participation in a day-ahead market. Bonneville’s governing statutes grant the Administrator broad discretion to set the terms and conditions of transmission service, which would include any terms and conditions necessary to join a day-ahead market. Several statutory provisions provide the basis for Bonneville’s authority to determine the terms and conditions of transmission service.²¹² In general, these statutory provisions grant Bonneville the discretion to act in a business-like manner when selling transmission at cost-based rates and to make decisions to effectuate that goal. While the details of such changes would depend on the market design, Bonneville would continue to sell and provide transmission service under its OATT as it does today. Bonneville will continue to monitor the development of market rules associated with transmission, including potential changes in transmission

²⁰⁸ *Native Village of Venetie I.R.A. Council v. State of Alaska*, 944 F.2d 548, 554 (9th Cir. 1992) (citing *Goodyear Atomic Corp. v. Miller*, 486 U.S. 174, 184–85 (1988)).

²⁰⁹ 16 U.S.C. § 839e(i).

²¹⁰ 16 U.S.C. § 839e(a)(1).

²¹¹ 16 U.S.C. § 839e(a)(2).

²¹² 16 U.S.C. §§ 832a(b), 832a(f); 16 U.S.C. § 837e; 16 U.S.C. §§ 838b, 838d.

revenue due to market impacts and congestion rent design, to assess potential transmission customer impacts. Bonneville would conduct a terms and conditions proceeding to update its tariff with any changes necessary to enable day-ahead market participation. Section 9 of Bonneville's OATT describes the process for changing terms and conditions. Such a proceeding would be in accordance with Section 212(i)(2)(A) of the Federal Power Act.²¹³

8. Bonneville will continue to meet its environmental obligations, including those under the Northwest Power Act, Endangered Species Act, and National Environmental Policy Act.

Another important set of Bonneville responsibilities involves the operation of the hydro system in coordination with the U.S. Army Corps of Engineers and the Bureau of Reclamation. The agencies manage the Federal Columbia River Power System for multiple project purposes including flood control, navigation, irrigation, fish and wildlife, power production, and recreation. Bonneville's participation in Markets+ cannot conflict with meeting non-power objectives, and Bonneville must continue to meet its environmental statutory obligations. As discussed herein, the designs include special considerations for hydro bid curves to recognize obligations and operational flexibilities of hydropower projects. The Markets+ designs do not appear to present a conflict with meeting these objectives, but as more details are developed it is essential that Bonneville maintain the flexibility and discretion necessary to meet non-power objectives. Bonneville will continue to ensure that Federal Columbia River Power System projects are managed for all project purposes and recognize system-wide operating constraints.

In a day-ahead market context, Bonneville would maintain operations to support ESA-listed fish species. Bonneville would also continue to meet Northwest Power Act requirements. Bonneville's power marketing services and activities, and its actual power operations to meet load obligations, would continue to be conducted consistent with applicable Biological Opinions and within existing operating constraints and normal operating limits of the projects. If Bonneville were to pursue participation in a day-ahead market, it would also assess the potential environmental effects that could result from implementing the decision consistent with the National Environmental Policy Act.

9. Conclusion

Bonneville's decision to join any market must comport with its legal obligations including to provide preference and priority in the sale of power, make firm power sales under section 5(b) of the Northwest Power Act, provide transmission service and operate the transmission system, set rates sufficient to repay the federal investment, and fulfill environment, fish and wildlife obligations. Bonneville has not identified any legal impediment to meeting these objectives if it joins Markets+.

²¹³ 16 U.S.C. § 824k(i)(2)(A).

Appendix B

West-Wide Governance Pathways Initiative Overview and Assessment

In July 2023, the West Wide Governance Pathways Initiative was launched with a mission to develop and form a new and independent entity with an independent governance structure capable of overseeing an expansive suite of West-wide wholesale electricity markets and related functions. This effort was led by a Launch Committee comprised of representatives from across a wide range of sectors. While its working meetings were closed, the Launch Committee held monthly public stakeholder workshops to provide updates on progress. Work products were released throughout the process and there was an opportunity for public comment. It is worth noting that the Western Area Power Administration, another Federal power marketing administration, participated on the Launch Committee. Bonneville participated in all public stakeholder meetings and provided comment at every opportunity. Bonneville was also an active participant in Pathways Step 2 work groups and contributed significant staff time to that effort.

The Pathways initiative resulted in two outcomes: Step 1 proposed a transition of the WEM Governing Body from a governance model of joint authority to one of primary authority with a provision for dual filing by the WEM Governing Body and CAISO Board of Governors at FERC in the case of an unresolvable dispute (discussed above). Step 2 proposes a significant transition to create a Regional Organization (RO) with an independent board that governs the WEIM and EDAM Tariff. Under the proposed approach, CAISO would continue to operate the market, would hold all financial and contractual liability, and maintain a shared tariff between CAISO and the RO. Some limited staff responsibilities may shift to the RO; however, the specifics of staffing remain open at the time of the final Step 2 proposal to be determined during the formation of the RO. The final proposal recommends that the new RO undertake a feasibility study within 9 months of formation to evaluate further advancements in market independence. The full Step 2 proposal can be found [here](#).

Assessment of Pathways Step 1

Bonneville has evaluated the outcomes of the Pathways initiative as part of its day-ahead markets decision process. Bonneville believes that Step One, by itself, does not achieve the level of independence from any one state's authority that is necessary for a regional market. Bonneville does not view Primary Authority as more independent than Joint Authority. Bonneville is concerned that the transition to Primary Authority could lead to the CAISO Board of Governors being disconnected from WEIM and EDAM issues and could increase conflict between the Board of Governors and the WEIM Governing Body.

Under Step 1, the CAISO Board of Governors would retain sufficient authority to take back the steering wheel when certain conditions arise (to maintain fiduciary responsibility under California law) described as exigent circumstances. "Exigent circumstances" is a very broad concept, and by its nature, would likely be called upon during a crisis, e.g., a reliability event, a price spike, or a call by California-elected officials to take action. Such events will be sudden and chaotic. It would be concerning for parties outside of California to be exposed to a sudden assertion of control by the CAISO Board of Governors when the WEM Governing Body, by the nature of its primary focus on the market, may have superior understanding of the issues.

The Step 1 proposal does not achieve independent market governance to meet Bonneville's principle.

Assessment of Pathways Step 2

As described above, the Step 2 final proposal represents a significant shift from the current governance structure of the WEIM and EDAM. It moves governance of those markets to a Regional Organization with an independent board. Market operations would remain under the single CAISO Tariff that includes

CAISO's administration of its BA. The RO would hold sole authority for sections of the CAISO Tariff applying to market operations and joint authority with the CAISO BOG for tariff provisions of overlapping application to both markets and the CAISO BA. The RO acts as a policy organization, governing policy related to the markets. Operation of the market remains with CAISO, as does corporate and financial liability related to the market. The step 2 final proposal also describes significant changes to the stakeholder process to enhance the role of stakeholders and shift away from the staff-driven process that CAISO uses today.

In evaluating the Step 2 proposal, Bonneville assessed whether the proposed approach achieves independent governance for markets. Under the proposal, the RO board members would be nominated and chosen through an independent sector-based process; they would not be selected by the California governor and confirmed by the California Senate, which is an advancement from the current state. However, market operations and administration would remain under the direction of the CAISO Board of Governors and, therefore, would not achieve full independence from the State of California.

Bonneville does not believe the Pathways Step 2 achieves the independent governance contemplated in Pathways' charter. This appraisal is not a matter of subjective opinion about what degree of independence would be good enough; the proposal creates conflicts that undermine any claim of independent governance and operations. As discussed below, the Regional Organization proposed by Pathways does not achieve independent market operations, an independent tariff, independent contracts, and the ability to provide RTO services absent future legislation. The market contemplated by the proposal remains California's market, adding an independent policy board with limited authority for market operations and administration.

1. Independent Market Operations

First, the Regional Organization would not have independent oversight and administration of market operations. Instead, the market would continue to be operated by the market's largest BAA, CAISO. This sets up a conflict of interest. For governance to be independent, CAISO should have the same role as any other BA in the market.

The RO board may find itself in a frustrating situation. While it has authority in market design, it would have no executive authority to manage operations to ensure the market is faithfully implemented. Further, the RO will be forced to take market operations services from a single provider without regard to potential competitive market operation services. The proposal notes that, while a typical arms-length contract allows a dissatisfied party to choose to not continue doing business with the other, "[t]he RO would be more or less required to use the CAISO[.]" Operations would answer to a state entity, with no remedy available to the Regional Organization.

Without legislative change, CAISO and its employees would remain subject to California legal requirements to act for the benefit of California. *See* Cal. Pub. Util. Code § 345.5. The market would be operated by a single BA in the market footprint with duties to itself and its state. Pressure to favor California could manifest in subtle ways, such as how issues are framed and presented, and in prioritizing work under time and staffing constraints. Bonneville believes that California regulatory agencies and the state's legislature will retain disproportionate influence on policy development. The Pathways proposed role for the Regional Organization to weigh in on select hiring decisions is a small step forward but ultimately does not get to the heart of the issue.

Bonneville is also concerned that this conflict of interest and lack of operational authority for the RO will have impacts on participants in emergency or shortage situations. The Pathways proposal states it is standard practice for operators to be able to act in an emergency without seeking advance blessing from a board. Bonneville is not advocating for emergency operations to be brought to a board before responding to a crisis. Instead, it is imperative that operations are independent, so the operators have no incentive to

favor one participating BA. Until CAISO's load service responsibility and Western energy market operator responsibilities are performed by completely separate entities, the market will not be independent.

2. Independent Tariff

Second, the proposal recommends an integrated tariff with continued joint authority over many tariff sections. The Regional Organization would not have sole authority over the tariff. The CAISO tariff would remain the relevant tariff. An integrated tariff creates conflicts over who has authority over which provisions, and who decides how certain initiatives are classified. An independent market would not intentionally choose to integrate its tariff with that of a single participating BA. From a practical standpoint, joint management of a tariff would be needlessly cumbersome and inefficient. From a legal standpoint, the ambiguity regarding authority could result in unjust and unreasonable implementation of the tariff.

Joint provisions are not necessary. General provisions could be copied and pasted to create two separate tariffs. Provisions specific to CAISO BAA could be unwound from sections that should be under the Regional Organization's sole authority. For the Regional Organization to have independent authority, it must be clear what authority it possesses. If the reluctance to separate tariffs is driven by cost considerations or the difficulty of precisely defining CAISO's new role, it is worth the investment now to address the issues to ensure unambiguous, just, and reasonable terms and conditions rather than in the heat of a future controversy. In order to achieve an independent governance structure, separate tariffs are a necessity.

3. Independent Contracts

Under the Step 2 proposal, CAISO would remain the counterparty to contracts with other market participants. This status is unique among participating BAs. It creates conflicts if CAISO interprets the contract differently than the Regional Organization. This could be a problem for CAISO if CAISO disagrees with the Regional Organization over what market rules are required or prohibited by the contracts. This is problematic for the Regional Organization if it adopts market rules applicable to scheduling coordinators and participating generators but lacks privity to enforce any related contract action. It is not clear that the Regional Organization would have any authority to amend contracts if it determines such amendments are necessary or desirable. Even if CAISO and the Regional Organization attempt to coordinate and align on interpretations, this continues to give one market participant undue influence over contracts with all other market participants. One participating BA should not be able to wield influence over the contracts of all market participants. As proposed, this contractual influence would not be shared or checked even by the Regional Organization itself.

These conflicts would not simply be philosophical differences of opinion. Under option 2.0, CAISO would retain financial responsibility, liability, and compliance obligations, which represents significant risk for CAISO. Therefore, when conflicts occur, the stakes will be high, and CAISO will naturally be incented to act in its own interest. The party that sets market rules should be impacted by the practical financial and legal ramifications of those rules. When the relationship between authority and impact is severed, as they are in the Step 2 proposal, conflict is inherent.

Despite the foregoing critique, Bonneville supports and appreciates the advancements made in the stakeholder process in the Step 2 final proposal. It has been Bonneville's experience that a more stakeholder-driven approach leads to increased collaboration, compromise, and ultimately better outcomes for market stakeholders. The Pathways Step 2 proposal introduces a stakeholder process with an increased role for stakeholders, including a more empowered stakeholder representative committee and indicative voting. The final proposal also includes an appropriate role and representation for federal power marketing administrations in both the stakeholder process and public interest process.

Appendix C

Potential Regional Transmission Organization Formation

Consistent with Bonneville’s strategic plan, Bonneville is considering an incremental approach to market expansion. While Bonneville is only considering day-ahead market participation in this process, Markets+ may offer more potential for further integration into an RTO. SPP is a fully independent entity that does not require any legislative changes to meet FERC’s requirements for RTO operation. In contrast, Bonneville has not observed a similar pathway for CAISO to support a full, multi-state RTO, including BAA consolidation. Even the most aggressive Pathways Initiative phase results in California as an ISO with the potential for a separate RTO operating outside of California in multiple states. SPP also has decades of experience operating a multi-state RTO, and its stakeholder-driven governance framework effectively navigates complex issues, while building trust among stakeholders. Accordingly, the Markets+ design is better positioned to provide additional market evolution and business opportunities for Bonneville as it confronts an increasingly dynamic electric utility business environment. If Western utilities begin to contemplate RTO formation in the future, Bonneville would conduct a transparent public process to evaluate the potential impacts of joining an RTO.

Appendix D

Seams Assessment

1. Transmission Operations, Seams, and Related Agreements

Seams are not a new concern for utilities, load serving entities, merchants, or marketers operating in the Western Interconnection. There is a mix of both bilateral trading and participation in organized markets, such as CAISO markets (day-ahead, hour-ahead, and WEIM) and WEIS. Bonneville has a service territory spanning seven states and is a significant provider and operator of high-voltage transmission service in the Pacific Northwest. Bonneville also operates a BAA in the Pacific Northwest that is adjacent to 18 BAAs (~360 individual ties) and 15 TSPs, including several TSPs that are embedded within Bonneville's BAA. Further, Bonneville is currently participating in the WEIM along with 14 of its adjacent BAAs.

While many diagrams and maps of the WECC and the Pacific Northwest often show tidy contiguous borders between BAAs and TSPs, the reality is much more complicated, especially in the Pacific Northwest, where many BAAs are often non-contiguous with loads and resources pseudo-tied across multiple TSPs and geographic zones, including generation-only BAAs. Bonneville also plays an integral role in the WECC as a key TSP, TOP, and TO of transmission assets that provide connectivity both within the Pacific Northwest and between the Pacific Northwest and the rest of the WECC footprint.²¹⁴ Given the numerous and complex commercial and operational seams that Bonneville and other WECC entities deal with daily and that have been refined over 75+ years, the region and Bonneville will need to work collaboratively to address the introduction of multiple new day-ahead market seams.

Seams exist today and produce operational and commercial friction and inefficiencies that must be carefully managed. Bonneville will likely have generation, load, and transmission participating in or impacted by both markets requiring various agreements, constraints, protocols, procedures, and market designs to ensure operational and commercial seams issues are addressed. With the introduction of multiple day-ahead markets with their own footprints, designs, protocols, and procedures, avoiding negative operational and commercial externalities will be critical.

The operational and commercial situation in WECC stands in stark contrast to the RTOs/ISOs that exist in the Eastern Interconnection.²¹⁵ In eastern RTOs/ISOs, they are vertically aligned among roles²¹⁶ as well as having mostly contiguous footprints (relative to WECC). As such, the types of seams and the negotiation of seams among the various operational and commercial concerns involve far fewer parties and less complexity. The introduction of additional day-ahead market seams in WECC will involve many more entities than would be present under an RTO/ISO regime.

To combat these complexities, Bonneville will engage entities early and with ideas of how to decrease the relative complexity. Depending on the footprint, multiple MOs and RCs will need to be involved in these conversations. Bonneville has extensive experience in developing transmission and operating agreements with multiple BAAs and Bonneville will bring that experience and understanding to the conversation.

The discussion below identifies examples of the types of commercial and operational seams that the region and Bonneville will need to address to implement multiple day-ahead markets in the WECC.

1.1. Operational Seams

1.1.1. Balancing Authority Area

²¹⁴ E.g., Northwest AC Intertie (NWACI) and Pacific DC Intertie (PDCI).

²¹⁵ E.g., SPP, Pennsylvania, New Jersey and Maryland Interconnection, Mid-Continent Independent System Operator.

²¹⁶ I.e., RC, MO, BAA, TSP.

BAAs may experience increased operational complexity due to the need to manage interactions with multiple day-ahead markets simultaneously. Each market may have its own scheduling, dispatch, and settlement processes, requiring BAs to coordinate their activities to ensure integration of market transactions while maintaining reliability.

1.1.2. Reliability Coordination

Multiple non-contiguous RCs in the Pacific Northwest with complex seams will make it potentially more difficult to reliably manage operational issues when they arise given the additional coordination and lack of complete regional authority. Existing multiple RCs in the Pacific Northwest have much simpler seams today.

This may be further complicated by the difference in BAA and TOP areas (geographical or electrical). Bonneville is the TOP for facilities that are not in the Bonneville Transmission BAA (e.g. Heyburn/Unity are in Idaho Power's BAA and Drummond/Swan Valley are in PAC East's BAA). Under the NERC [Rules of Procedure](#) (*ROP Section 500, 1.4.1*), all areas (*geographic or electrical*) are required to be "under the oversight of one and only one RC." There are currently no situations in the Pacific Northwest where a BA or TOP takes services from multiple RCs. If there are multiple markets within the Pacific Northwest with each taking primary RC services from the respective MO organization, this creates a possibility that some entities that perform these functions over areas that transcend the footprints of more than one market may be required to take services from more than one RC. This complexity may make it more difficult to reliably manage certain operational issues when they arise, as well as increase the communication and compliance burden.

RC-RC coordination will be critically important to minimize reliability risks. Bonneville has not made any determination regarding whether if Bonneville will switch RCs. However, having multiple non-contiguous RCs and MOs in the Pacific Northwest will pose many operational and commercial challenges due to:

- Potentially complex and non-contiguous boundaries;
- Competing priorities and objectives;
- Unique requirements, business practices, and complex coordination needs;
- Complex seams agreements.

These types of seams pose many challenges that, if not addressed and mitigated, will impact reliability. Through implementation, Bonneville will seek to lessen these impacts and risks.

1.1.3. Transmission Operations

The Pacific Northwest to California transmission corridor is one of the most important in WECC. A problem along this corridor can have serious implications for the entire Western Interconnection, and specifically, entities within the Pacific Northwest that depend on the Bonneville Transmission System. Further, many of the paths for which Bonneville is the TOP are shared amongst multiple asset or capacity owners and TSPs. These include, but are not limited to:

- **NWACI:** Many entities are involved in the NWACI. Bonneville is the operator and the BAA of the facilities north of the California Oregon Border. There are multiple asset owners (Bonneville, PAC, Portland General Electric [PGE]) and capacity owners, many who also provide service under an OATT as a TSP. The facilities that make up the NWACI support important transfers with CAISO, PAC, PGE, Idaho Power Company, BANC, and Nevada Energy, all of whom have either declared a leaning to join EDAM or signed an implementation agreement to join EDAM.
- **PDCI:** The PDCI is a controllable DC transmission path between the PNW (Bonneville

Transmission) and Southern California (LADWP), where LADWP has chosen to join EDAM. North of Nevada Oregon Border (NOB), Bonneville is the sole owner while south of NOB the ownership is split amongst multiple entities (LADWP, CAISO, Glendale, and Burbank). As operators of the DC converter stations at Celilo and Sylmar, Bonneville and LADWP control the PDCI dispatches and jointly manage the path.

- **South of Allston:** South of Allston is a shared path between Bonneville, PGE, and PAC, with the latter two having signed EDAM implementation agreements. Like other paths, Bonneville manages the path and determines the total transfer capability, which is subsequently allocated.
- **Other Shared Paths Include:** North of Echo Lake, West of Hatwai, North of Pearl, Montana-Northwest, and the Northern Intertie.

These types of shared paths impact multiple TSPs and BAAs and must be carefully managed and coordinated. Situations that increase the amount of coordination and seams issues on paths like these may increase the risk of adverse commercial and operational outcomes. Depending on the ultimate RC and market footprints, new agreements and procedures may need to be developed in order for everyday operations to continue to be reliable and efficient.

1.1.4. Mismatch Between Market Processes and Real-Time Operations

Each market may have differences in processes such as interchange scheduling rules, scheduling intervals, timing requirements, intertie bidding, rules for submitting bids and offers, and market clearing timelines. This misalignment can lead to difficulties in coordinating generation and transmission schedules between the two markets and aligning market schedules and dispatches with real-time operations. As part of implementation, Bonneville will need to consider all of these aspects as procedures and protocols are developed. The details will not be known until implementation.

1.1.5. Transmission Constraints and Market Congestion

Differences in how transmission constraints are modelled, market flows are calculated, and how subsequent flows are managed in each market can result in congestion at interfaces between or within the two market footprints. This “market congestion” or “commercial congestion” may affect the efficient utilization of transmission capacity and lead to suboptimal dispatches and pricing outcomes. Transmission opt-outs, SFCs, Transmission Corridor Constraints, ETSRs, and other nuances of each market’s management of transmission constraints may cause the market(s) to be commercially constrained even though the transmission system is not physically overloaded.

1.1.6. Congestion Management

There is a potential of physical congestion occurring on transmission lines that serve as interfaces between the markets or transmission lines/flow gates/paths internal to one or the other market footprint. This congestion can occur regardless of being part of a market, but the management of congestion on transmission being used by two markets will likely require a more complex and nuanced approach. Managing congestion can also be more complex when market participants seek to arbitrage price differentials between markets, leading to potential congestion on specific transmission paths or flow gates. Seams agreements will likely be needed between the impacted entities²¹⁷ and the market operators to try and manage these types of operational risks.

1.1.7. Dynamic Transfer Capability (DTC)

Bonneville has numerous facilities with DTC limitations, such as the Northern Intertie, NWACI, PDCI,

²¹⁷ E.g., BAAs/TSPs/TOPs.

Montana Intertie, and more generally across the Bonneville network. These limitations impact the ability of the system to reliably support large sub-hourly changes in flows and are addressed in Bonneville's Dynamic Transfer Business Practices. If there are multiple real-time markets within the Pacific Northwest, DTC will need to be allocated among multiple markets and managed via market constraints.

Further, the lack of DTC between two non-contiguous market zones (e.g., PNW and DSW) will limit sub-hourly optimization between the zones. Each zone, and the BAAs it contains, will need to manage intra-hour imbalances without the market's ability to economically transfer incremental energy dynamically between the zones. As a result, and to maintain reliability, the need for flexible resource capacity may increase, requiring either additional market procurements and/or additional reserves to be held by BAAs within each zone.

1.1.8. Interconnection Reliability Operating Limits (IROL)

Bonneville is currently subject to two IROLs, the Oregon Net Export IROL²¹⁸ and the NW WA Import IROL. Today, RC West is largely responsible for both IROLs. Having multiple non-contiguous RCs involved in managing IROLs, especially the Oregon Net Export IROL, will require the RCs to be tightly coordinated. Bonneville will continue to support large margins when studying and observing IROL limitations and also support the identification of a lead RC for each IROL.

1.1.9. Network Model Management / Coordination

Accurate models are critical to maintaining reliability. If there are multiple RCs, they will need to ensure they always have the same network models and that they communicate consistently to all BAs and TOPs. Bonneville will continue to advocate that RCs ensure network model alignment.

1.1.10. Operational Studies (assumption, datasets, outages, etc.)

Operational studies require not only an accurate network model, but also robust and accurate datasets and the ability to apply realistic assumptions. With multiple RC and market footprints in the Pacific Northwest, this may be a challenge and present risks across various time horizons.²¹⁹ Bonneville will continue to receive the assumptions from WECC as part of its offline studies, while the real-time contingency analysis tool will be using remote terminal units to receive real-time data and then perform state estimation.

1.1.11. Outage Coordination

Coordinating and managing outages across multiple MOs and RCs is critically important. In addition to using different Outage Management Systems, RCs and MOs may have differing requirements for outage submittals and timings and a single outage may require careful coordination with all entities depending on the nature of the outage. As part of any implementation, this will need to be further explored and coordinated.

1.2. Commercial Seams

1.2.1. Market Timing and Process Requirements (bi-lateral, day-ahead, real-time)

Differences in timing and process requirements between the various markets (day-ahead, real-time) may impact the ability to efficiently trade between market footprints. Business practices will need to be developed to address efficiency and accurate operation.

1.2.2. Resource Adequacy Programs (i.e., WRAP and CPUC)

Multiple RA programs may be difficult to reconcile across market footprints. There will need to be market-

²¹⁸ The Oregon Net Export IROL addresses the interactions between the NWACI and Path 75/Path 14.

²¹⁹ Week-ahead, day-ahead, hour-ahead, real-time contingency analysis, etc.

to-market coordination to ensure generation capacity, and any energy deliveries are accounted for.

1.2.3. Jointly Owned Transmission (network and inerties)

Managing existing jointly owned (asset or capacity) transmission agreements, along with any commercial arrangement and operational protocols, may be more difficult than they already are if the owners are spread across multiple non-contiguous RCs and markets. This is especially acute when one TSP and owner is located within a BAA that is participating in a different market. It will take time and engagement from all entities in the Pacific Northwest to ensure reliable operation and market efficiency.

1.2.4. Remote Load (i.e., load service in another BAA via transfer service)

Many utilities, including Bonneville, have generation and load in other BAAs. If the entity with remote load, such as Bonneville, has a different RC or the two BAAs are in different day-ahead and real-time markets, Bonneville acknowledges that it may be more difficult to service that load as it would likely require merchants to participate in both markets as well as deal with market-to-market energy transfers and it will need to be further explored upon implementation.

1.2.5. ATC ID, OATT, Business Practice Discrepancies between Adjacent TSPs or Joint Owners

While ATC ID, OATT, and business practice discrepancies exist today, depending on the design of the markets (timings, transmission donation processes, TSR queue pausing, etc.) and how transmission availability is calculated and reserved, adjacent TSPs may end up with impactful differences. These differences may cause bilateral trading and market-to-market friction. Affected parties will need to coordinate to minimize potential impacts.

1.2.6. Price Formation (between markets)

A critical concern of all organized markets is price formation methodology. Differences in these methodologies, both temporal and procedural, may result in structural price differences between markets that create incentives that work against both markets objectives or produce unintentional hurdles that limit efficient bilateral trades or efficient transactions between markets.

1.2.7. Commercial Transmission Rights (Congestion Revenue Rights, ATC, etc.)

Markets need access to transmission to effectively operate. Markets may leverage donated rights, unused ATC within the market footprints, physical capability of the system, or any combination of the above. Timing and access to transmission for day-ahead market participants and customers not participating in a day-ahead market may be complex to coordinate. Parties will need to establish methods to determine priority, transmission rights, and dispute resolution to avoid over or under-utilization of the transmission system. Proper incentives will more effectively manage congestion. Bonneville believes these complexities can be addressed through the standard tariff, rates, and business practice processes.

1.3. Other Seams Considerations

There are many other potential impacts to multi-RC/multi-MO environment that will need to be carefully weighed, such as:

- State Carbon Policies and GHG accounting
- Remedial Action Schemes
- Rate Pancaking (market to market)
- Data Sharing
- Market Flow Calculation and Management

- Reserve Sharing (market to market)
- Interchange Scheduling (timing requirements, etc.)
- System Integration and communication between markets
- Oversupply Protocols
- Transmission Loss Accounting
- NT redispatch (FCRPS and Non-Federal redispatch)
- Standardization of scheduling timelines between markets
- Water Management (Bi-Op)
- International Treaties
- Jurisdictional Status
- Blackout Restoration

1.4. Seams Agreements

Bonneville is likely to have generation, load, and transmission participating in or impacted by both markets. Bonneville expects agreements, constraints, and market design to mitigate operational and commercial seams issues. Given the complexity of WECC, the potential for non-contiguous market and RC footprints, and the number of parties involved, multiple types of agreement will be necessary.

2. Seams Conclusion

Bonneville recognizes the operational and commercial challenges posed by multiple markets and RCs, the impacts of their potential footprints, and the resulting seams. Bonneville also recognizes and is aware of the complexities posed by seams, both operational and commercial. So long as more than one RC, MO, BAA, and TSP exist in WECC, seams will exist. However, some create more operational and commercial challenges and complexity than others. Bonneville and others will need to work collaboratively to manage these seams while continuing to prioritize reliability.

Appendix E

Congestion Impacts

In a day-ahead market, congestion occurs when available least-cost energy cannot be delivered to some loads because transmission facilities do not have sufficient capacity to deliver the energy, or there is insufficient transmission rights made available. Market optimization will create a plan to dispatch least-cost resources until the optimization reaches an identified limit, at which point it will begin to add to the dispatch plan the next least-cost resource that does not further impact the “binding” limit. An indication that congestion is occurring is “price separation” between two locations; the next least-cost resource that does not further impact the limit that can serve load on one side of the constraint may have a different price than the next least-cost resource on the other side of the constraint. To see an example of congestion, please see materials from public workshop 7 on June 3, 2024.²²⁰

The market optimization engine delivers day-ahead awards with resource schedules different from those that may have been established bilaterally. Unlike bilaterally established resource schedules, the planned dispatch pattern that results from participating in a day-ahead market is security-constrained (i.e., factors generation and transmission constraints when creating the optimized dispatch). Bonneville Transmission Services would be using scheduling limits established from internal studies to determine the capability of each path. The planned dispatch pattern could fully use the capacity over a path based on the data it had been supplied. However, congestion may still occur.

On the next operating day, in real-time, operational constraints may deviate from what was expected in the day-ahead optimized dispatch. In real-time, resources are redispatched to reflect updated constraints as other inputs such as load changes, variable energy resource output changes, and generation or transmission outages and derates are adjusted relative to the day-ahead solution.

As stated in Section 6.4, Bonneville has had positive experiences leveraging the WEIM to manage operational constraints and expects even greater congestion management effectiveness with the addition of a security constrained day-ahead market optimization

Bonneville is likely to have generation, load, and transmission participating in or impacted by both markets. It is possible that in a multi-day-ahead market scenario, the Pacific Northwest region will continue to see commercial congestion, rather than a reduction. Physical congestion represents the actual flow on a transmission element reaching the established reasonable maximum amount. Commercial congestion represents a limit to potential physical flow despite the physical limit not being reached. Because Bonneville will likely have transmission customers in both day-ahead markets, as well as in no market, Bonneville will have to determine how to allocate transmission capacity to each market. If each market is allocated a certain number of MWs on a flow-based path that are reflective of the transmission rights of that market’s participants, each market may congest due to the commercial limits even though the physical limitation is not close to being reached. This could produce a less efficient solution for each market, especially in the day-ahead market, compared to if there was only one market or compared to how things are today in a bilateral market. This could also happen in the real-time horizon.

Another inefficiency that could be introduced is internal flow-based paths with expected counterflow and transmission rights that were originally sold based on non-coincidental use. Each market will have a unique portion of capacity for the same path, defined within their respective market. There could be the situation that the sum of all of the rights in a single direction add up to more than the capability of the path, in which

²²⁰ See Bonneville’s Public Engagement for Establishing a Policy Direction on Potential Day Ahead Market (DAM) Participation - Workshop 7 presentation (June 3, 2024), available at <https://www.bpa.gov/-/media/Aep/projects/day-ahead-market/2024/dam-workshop-7-presentation-060324.pdf>.

case scheduling limits would be needed for each market to fit the path limit. This would exacerbate the commercial congestion identified previously, because the non-coincident users may not be distributed between the markets in the same pattern as the coincident users. This might only be in the day-ahead market and then in the real-time market, scheduling limits could be relaxed based on the scheduled use.

As discussed in Appendix D, Bonneville plans to encourage the two market operators to begin developing a seams agreement that maximizes the efficient use of the transmission system while maintaining the reliable operations of the grid. With these future complexities in mind, Bonneville is proactively taking part in the Enhanced Curtailment Calculator Working Group (ECCWG) to advise on solutions for uniform congestion management process.

In summary, Bonneville believes there are likely congestion management benefits to transmission operations with Bonneville participating in a day-ahead market. In July 2023 and October 2024, Bonneville announced that it had identified multiple new transmission substation and line projects necessary to reinforce the Pacific Northwest's electric grid.²²¹ The completion of these projects will add capacity to Bonneville's transmission system, and the day-ahead market can deliver even more efficient dispatch solutions.

²²¹ See Press Release, Bonneville Power Administration, BPA takes major step to advance transmission projects for reliability and expansion (July 12, 2023), available at <https://www.bpa.gov/-/media/Aep/about/publications/news-releases/20230712-PR-08-23-bpa-accelerates-work-on-transmission-projects-final.pdf>; Press Release, Bonneville Power Administration, BPA maintains transmission expansion momentum with 13 new proposed projects (Oct. 15, 2024), available at <https://www.bpa.gov/-/media/Aep/about/publications/news-releases/20241015-PR-18-24-bpa-maintains-transmission-expansion-momentum-with-13-new-proposed-projects.pdf>.

Appendix F

Implementation Feasibility Assessment

In order to evaluate the implementation feasibility for Bonneville's Markets+ participation, a capability gap analysis was conducted, and 12 projects were determined to close the identified capability gaps in the following areas:

- Bidding and self-scheduling
- Data integration
- Settlements
- Price and dispatch
- Load and renewable forecast
- Metering
- Outage management
- Transmission scheduling and operations technology
- AGC modification
- RC Switch (if applicable)
- End-to-end billing process
- Post go-live technical support

Bonneville is in the process of developing an implementation plan to execute these projects, including changes in software, hardware, data integration, business processes, policies, and staffing. The implementation plan also includes market entry preparation, such as staff training, systems testing, market simulation, parallel operations, and production cutover. Initial estimates for funding and resources necessary to support this effort were included in Table 8 in section 5.1.2.3.

The main challenge of this implementation effort is the transition between two organized energy markets (i.e., WEIM to Markets+), which could require more resources to maintain two sets of systems and processes during the transition period. In many cases, discreet hardware, software, and network connectivity will be required to operate in parallel. Bonneville will strive to minimize the staffing impact by setting an appropriate timeline for implementation activities to space out the workload over time.

Bonneville will focus on deliberate timing, adequate funding, and appropriate staffing in the implementation process while leveraging prior experience implementing the WEIM. In addition, Bonneville plans to get support from a consulting services firm specializing in the energy utilities industry with expertise in market-to-market transition as a critical component to a successful and effective market entrance.

BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c))
Emergency Order: Transalta)
Centralia Generation LLC)
_____)

Order No. 202-25-11

Motion to Intervene, Motion for Clarification, and Requests for Rehearing and Stay
of Sierra Club, NW Energy Coalition, Washington Conservation Action, Climate
Solutions, Public Citizen, and Environmental Defense Fund
(collectively, “Public Interest Organizations” or “PIOs”)

Exhibit 1-94:
Power Council 2024 Resource Program Results

Jeffery C. Allen
Chair
Idaho

Ed Schriever
Idaho

Doug Grob
Montana

Mike Milburn
Montana



Northwest Power and Conservation Council

KC Golden
Vice Chair
Washington

Thomas L (Les) Purce
Washington

Ginny Burdick
Oregon

Louie Pitt, Jr.
Oregon

January 7, 2025

MEMORANDUM

TO: Council Members

FROM: Jennifer Light, Director of Power Planning

SUBJECT: Bonneville's 2024 Resource Program Results

BACKGROUND:

Presenters: Suzanne Cooper, Senior Vice President of Power Services
Ryan Egerdahl, Manager of Long Term Power Planning
Allie Mace, Manager of Market Analysis and Policy
Eric Federovitch, Manager of Long Term Power Sales and Purchase

Summary: Bonneville has finalized its 2024 Resource Program (also known as RP-24). Bonneville's resource program is an analysis of potential system needs and resources available to meet those needs. Bonneville staff will join the Council to share the results from the 2024 Resource Program and early thinking on preparations for its next resource program, which is planned to be completed in September 2026.

Relevance: The Resource Program is informational and not a decision-making process, nor a decision document, but the results do inform Bonneville's resource acquisition strategies. For the past several years, Bonneville has been working with its customers and the region on new contracts for the post-2028 period. These conversations have highlighted that Bonneville may need to acquire additional resources to serve its obligations under these new contracts. Bonneville has stated that the 2024 Resource Program is expected to provide insights to

customers on potential resource types that Bonneville might pursue to serve that obligation.

When acquiring new resources, Bonneville is required to act consistent with the Council's power plan. Therefore, it is critical for the Council to understand the results of the current resource program, and how the results align with the Council's current power plan (the 2021 Power Plan).

It is also worth keeping in mind that Bonneville is starting to work on its 2026 Resource Program (RP-26), which it plans to complete by September 2026. The timing of this next resource program overlaps significantly with the Council's planned development of its Ninth Power Plan.

Background: Bonneville recently completed its 2024 Resource Program and presented the results in a [public workshop](#) on December 19th, 2024. Bonneville has stated publicly that this resource program is expected to provide insights to customers around the types of resources it might acquire should it need to acquire new resources to meet its future obligations.

The 2024 Resource Program includes results for a base scenario along with several sensitivities, including sensitivities that look at market prices, market reliance, and load growth. Bonneville also conducted a specific study exploring potential resources for Tier 1 augmentation.¹ Bonneville will walk through the findings of this analysis at the January Council meeting.

The Council's current power plan, the 2021 Power Plan, provides specific recommendations to Bonneville, which include:

- Acquire between 270 and 360 aMW of cost-effective energy efficiency by the end of 2027, of which at least 243 aMW must be from programmatic savings, and at least 865 aMW by 2041
- Work to enable and encourage its customer utilities to pursue low-cost and high value demand response, including time-of-use rates and demand voltage regulation
- Look to mid-term and long-term market resources for additional energy when needs are beyond those met by the recommended energy efficiency and demand response resources
- Compare market products, both in price and capacity, to renewable power purchase agreements to ensure that the lowest-cost product that suffices to meet any need is identified.

¹ Under the Bonneville Provide of Choice Policy, which is guiding its post-2028 contract development, Bonneville has agreed to sell 7250 aMW of power at a Tier 1 rate. Based on the existing system capability, Bonneville may need to acquire additional resources to meld into the existing Federal Base System in order to meet that obligation. This study focused specifically on the question of which resources would be least-cost to meet that obligation.

It is worth noting that Bonneville's near-term results across all sensitivities (i.e. pre-2030 builds) and its Tier 1 augmentation study are consistent with the 2021 Power Plan recommendations. Staff recommend the Council focus more on these near-term results, given the Council is working to complete its next power plan by the end of 2026 and Bonneville will have an updated resource program in a similar timeframe.

While the near-term results make sense, and are consistent with the Council's power plan, staff does have some questions regarding the longer-term results. Staff shared these concerns with Bonneville at the December 19th public workshop. They include:

Modeling of Emerging Resources: Bonneville included one emerging resource option, small modular reactors (SMRs), in RP-24. Council staff recommend Bonneville consider more emerging resource options in RP-26. Since different emerging resources have different attributes, analyzing more options will provide better information to Bonneville on the types of resources needed for the long-term. For reference, Council staff are planning three emerging resource options for the next plan. Council staff also recommend Bonneville rethink some of the SMR specific assumptions, particularly around online date and lifetime. Bonneville assumed the SMR was available in the model as soon as 2030. The Council understands the online date for SMRs would be 2035 at the earliest based on statements from Energy Northwest staff. The timing of emerging resource availability may change resource decisions across the planning horizon. The Council plans to explore different online dates for emerging resources in its scenario modeling to understand the implications of this uncertainty. Additionally, Bonneville assumed a 60-year life for the SMR. The assumed lifetime can significantly change the economics of a resource, with a longer lifetime making a resource look cheaper in the modeling. In the 2021 Power Plan, the Council used a 40-year life, and utilities across the region have used a range of assumptions from 30-years to 60-years. Council staff are still working with its advisory committees on the best assumptions for the upcoming plan.

Improved Understanding of Modeling Approach: Bonneville developed a new approach to its resource optimization modeling for RP-24. The newly developed optimizer provided a good step forward for Bonneville over the previous approach. Council staff are interested in better understanding the model, particularly as some of Bonneville's results are counter intuitive. As we have found with our own model development, there is significant value in opening up the models to experts in the region. The rapidly changing power system requires new modeling approaches, which the whole region is struggling to resolve. Having the opportunity to dive deeper will increase understanding and ultimately improve the modeling for all parties.

Council staff intend to work closely with Bonneville on the development of the Ninth Power Plan and Bonneville's next Resource Program.

More Info: Materials related to Bonneville's Resource Program development are available on its website: <https://www.bpa.gov/energy-and-services/power/resource-planning>.



BPA 2024 Resource Program & Next Steps

Presented to the Northwest Power and
Conservation Council
January 14th, 2025



Introductory Remarks

Suzanne Cooper

Senior VP, BPA Power Services

Resource Program Process Update and Next Steps

Ryan Egerdahl

Manager, Long Term Power Planning

Agenda

- Resource Program Process Update and Next Steps
- RP24 Resource Solutions
- Power Services Resource Acquisition Process

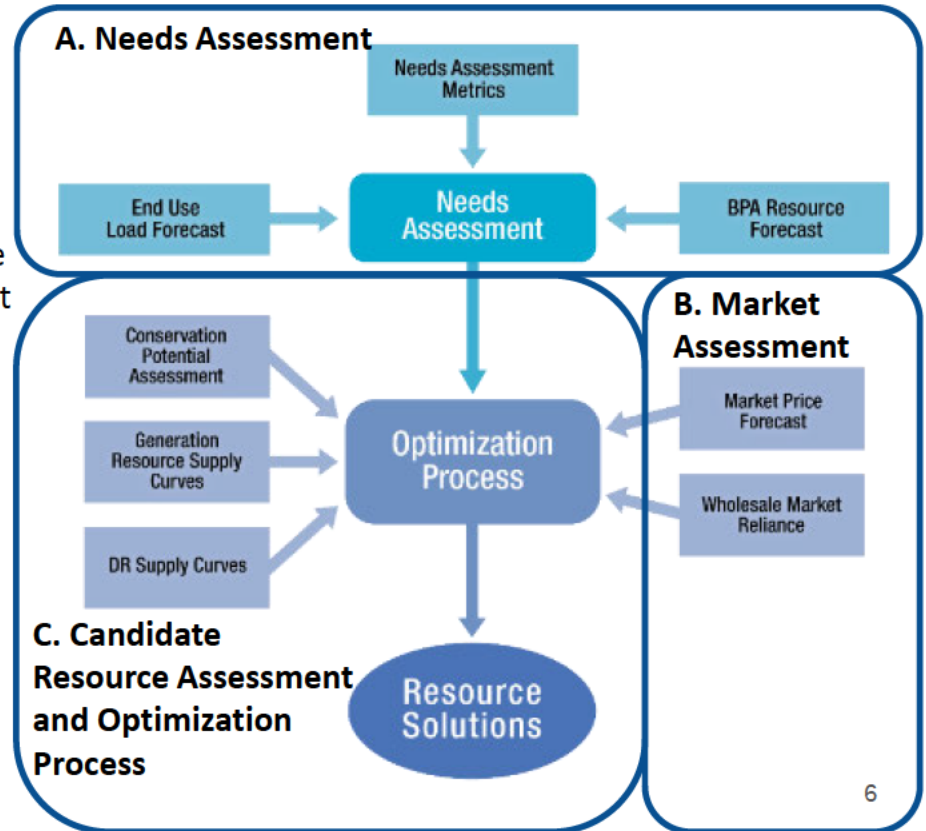
Reminder: Power Planning at BPA



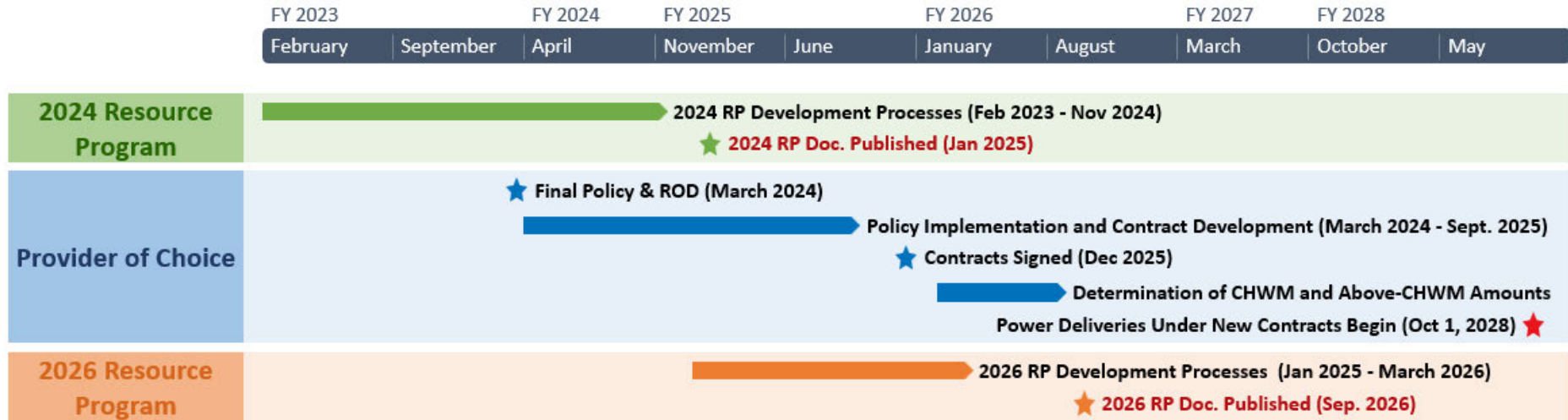
- Each year, BPA publishes the Pacific Northwest Loads and Resources Study – often referred to as the **White Book** - which analyzes BPA's projections of retail loads, contract obligations, contract purchases, and resource capabilities over a 10-year study horizon and describes expected energy and capacity surplus/deficits under varying water conditions.
- On a biennial basis, BPA conducts an IRP-like assessment collectively referred to as the **Resource Program** which examines uncertainty in loads, water supply, natural gas prices, and electricity market prices to develop least-cost portfolios of resources that meet BPA's obligations.
- These processes are voluntarily undertaken to inform acquisition strategies and provide valuable insight into how Bonneville can meet its obligations cost-effectively. They are neither decision documents nor a process required by any external entity.

Resource Program Process

- A. The **Needs Assessment** measures the federal system's expected generating resource capabilities to meet projected load obligations
- B. The **Market Assessment** simulates the evolution of power markets in the Western Interconnect to generate a long-term forecast of Mid-Columbia prices and market availability under a variety of generation, load, and economic conditions
- C. The **Candidate Resource Assessment and Optimization Process** explores how the varying costs, performance, and availability of candidate demand-and-supply-side resources (including conservation, demand response, market purchases, and generating resources) as well as wholesale market reliance can be used to provide a least-cost resource strategy for meeting identified needs



Resource Program and Provider of Choice



Possible Enhancements for RP26

- Based on feedback to RP24, BPA will consider exploring a range of modeling enhancements for RP26, including but not limited to:
 - Assess capacity metric under extreme weather and low water
 - Reintroduce balancing reserves study to Needs Assessment
 - Connect resource solutions to WRAP forward showing position
 - Include additional candidate resource options
 - Refine and refresh characteristics for candidate resources, including performance of renewables
 - Enhance linkages between resource solutions, market assessment, and needs assessment modeling
- We will also solicit additional feedback from stakeholders as RP26 planning gets underway

Next Steps and Additional Information

Next Steps:

- Publication of 2024 Resource Program expected in January 2025
- Release of BPA and Energy Northwest joint CGS EPU business case and RP24 addendum study expected spring 2025
- 2026 Resource Program to kick off in winter 2025; publication expected September 2026

Resource Program Contacts:

Ryan Egerdahl, Resource Program Manager, rjeagerdahl@bpa.gov

Brian Dombeck, Resource Program Coordinator, bjdombeck@bpa.gov

Find Us:

Email: ResourceProgram@bpa.gov

Web: [Resource Planning \(bpa.gov\)](https://www.bpa.gov/ResourcePlanning)



Resource Solutions

Allie Mace

Manager, Market Analysis and Policy

Key Takeaways – Resource Solutions

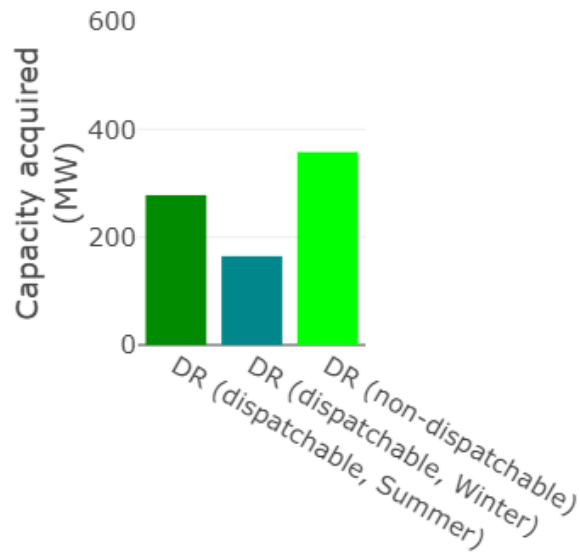
- We continue to rely heavily on **energy efficiency, demand response, and market purchases** to meet BPA needs.
- As loads grow or we add further limits on access to the market, resource acquisitions grow quickly.
- Acquisitions are driven primarily by **Flat** and **HLH energy needs**, rarely by super-peak or 18-hour capacity needs. There is not a single binding metric.
- Supply side acquisitions tend to focus on **solar** and **wind** resources due to their low costs and their contributions to energy needs.
- Supply side acquisitions in SWEDE are needed only if loads are higher than in the base scenario.
- **Resources in the model cannot meet needs in 2 sensitivities:** no market and high load. Shortfalls are in **winter/April 2026-2028**.

Base scenario: Key takeaways

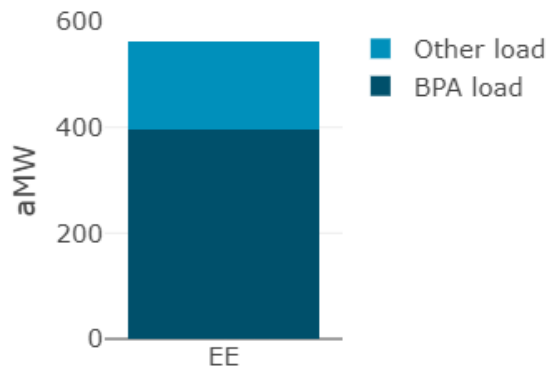
- P10 needs are met primarily by market purchases and energy efficiency (EE)
- Lowest-cost portfolio also includes several demand response (DR) programs and 300 MW solar power

Base scenario resource acquisitions

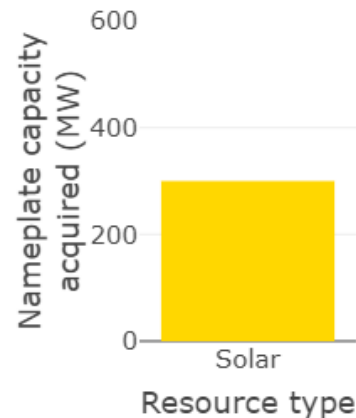
Demand response (DR):



Energy efficiency (EE):



Supply-side:



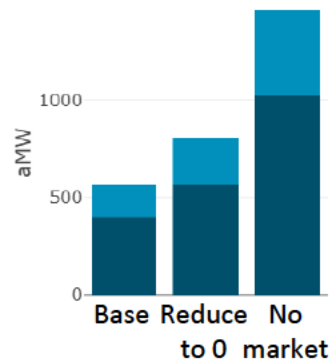
All values are for 2045. Nameplate capacities of supply-side resources represent maximum output under optimal conditions. Annual aMW output of resources such as solar and wind are substantially less than nameplate capacity. Capacity value for non-dispatchable DR is sum of max. capacity across all products.

Market limit sensitivities

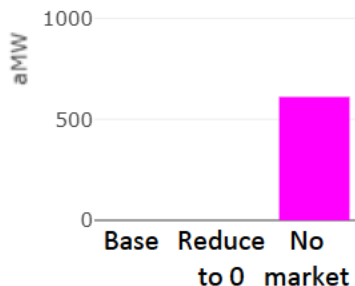
- **Reduce SPK/HLH by 25%:** Limits to SPK and HLH purchases are 75% of forecast market depth
- **Reduce SPK/HLH by 50%**
- **Reduce all market purchases by 50%**
- **Reduce to 0:** Limits start at 50% of forecast market depth and decline to 0
- **No market:** No market purchases allowed

Market limits: resource acquisitions

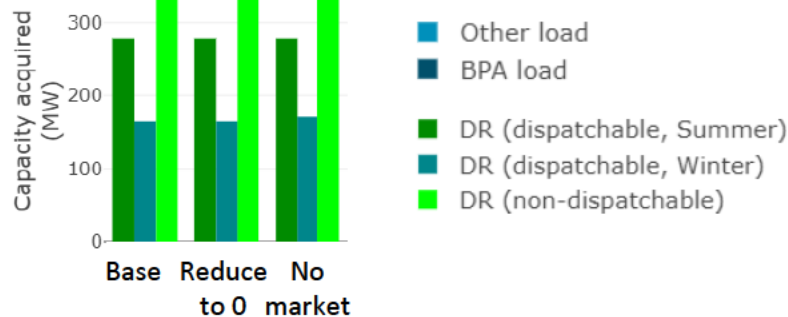
Energy efficiency:



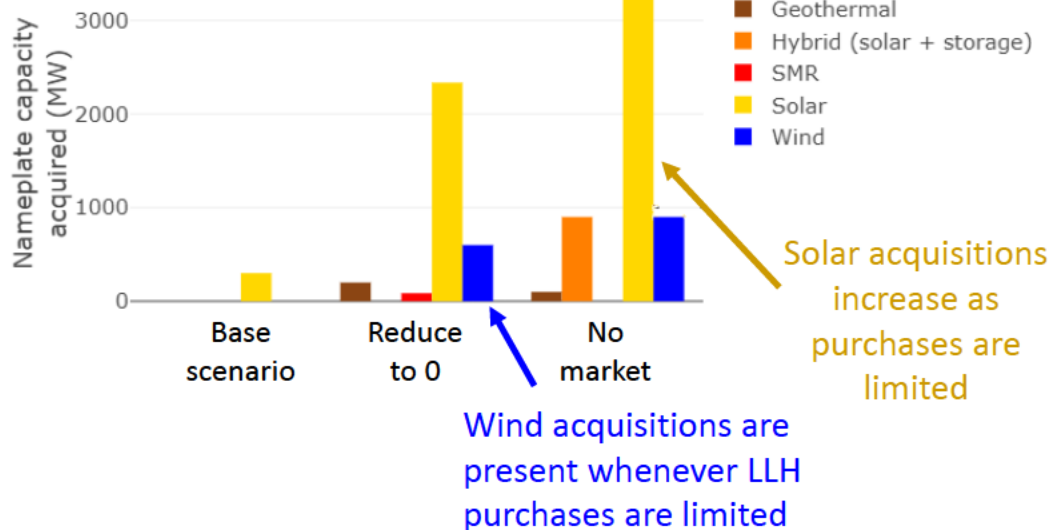
Unmet needs:



Demand response:



Supply-side:



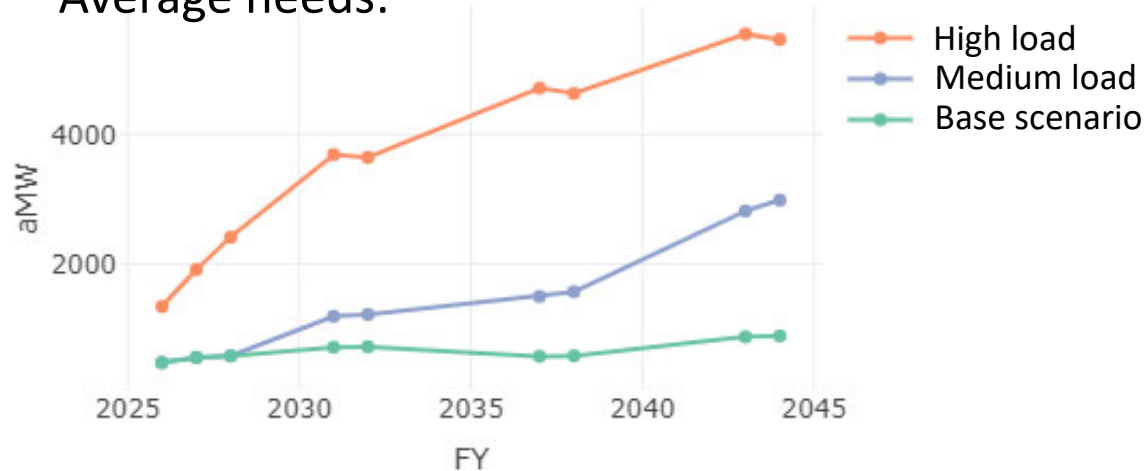
All values are for 2045. Nameplate capacities of supply-side resources represent maximum output under optimal conditions.

Annual aMW output of resources such as solar and wind are substantially less than nameplate capacity. Capacity value for non-dispatchable DR is sum of max. capacity across all products.

Load adder sensitivities

- **High load adder (aka, NR)** is a flat block load added to every hour uniformly across the year.
- **Medium load adder (aka, T2)** is shaped load added to each hour. Shaping is based on current Slice Block load shape.

Average needs:

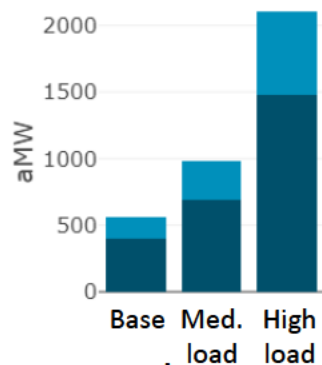


Load adder sensitivities: Key takeaways

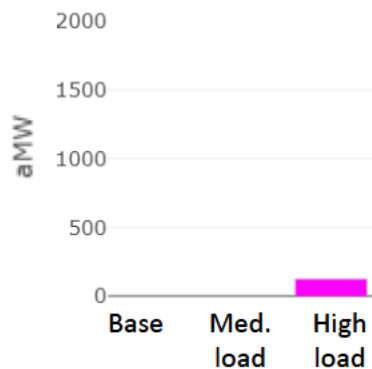
- Acquisitions are primarily driven by HLH energy needs
- Loads in the high load adder sensitivity are difficult to serve:
 - We do not have enough resources in the model to meet needs in 2026-2028 (but the shortfall is relatively small)
 - Portfolio cost is > \$35 billion
- Solutions to both sensitivities include large (1,000+ MW) acquisitions of SMR
- Most acquisitions in the medium load adder sensitivity happen late, in 2043

Load adder sensitivities: resource acquisitions

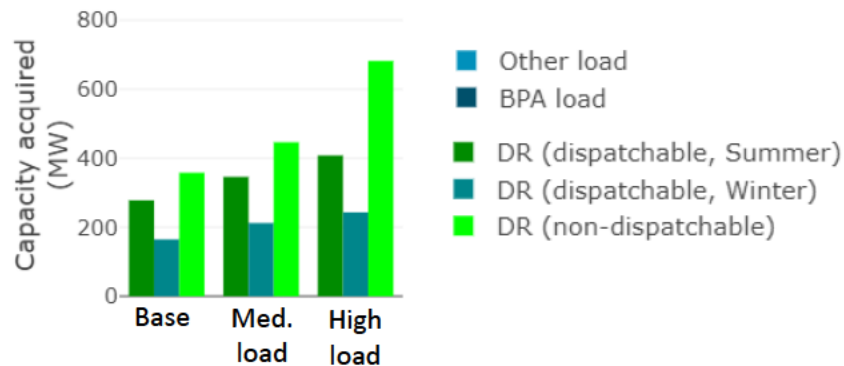
Energy efficiency:



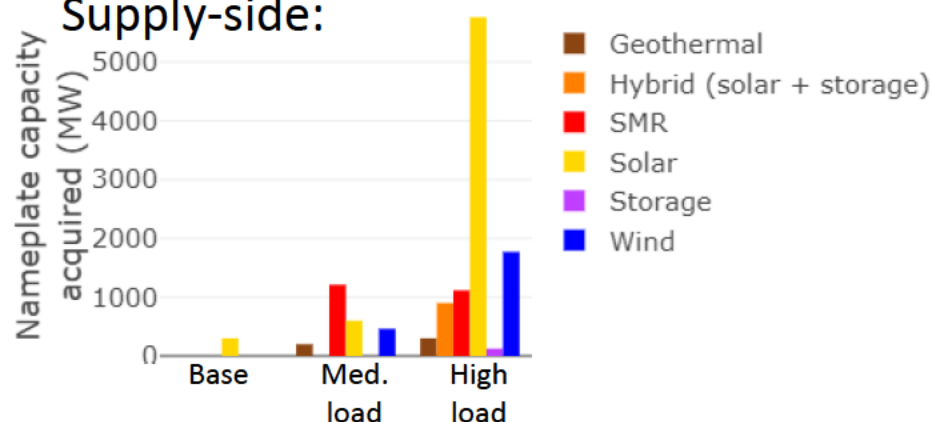
Unmet needs:



Demand response:



Supply-side:



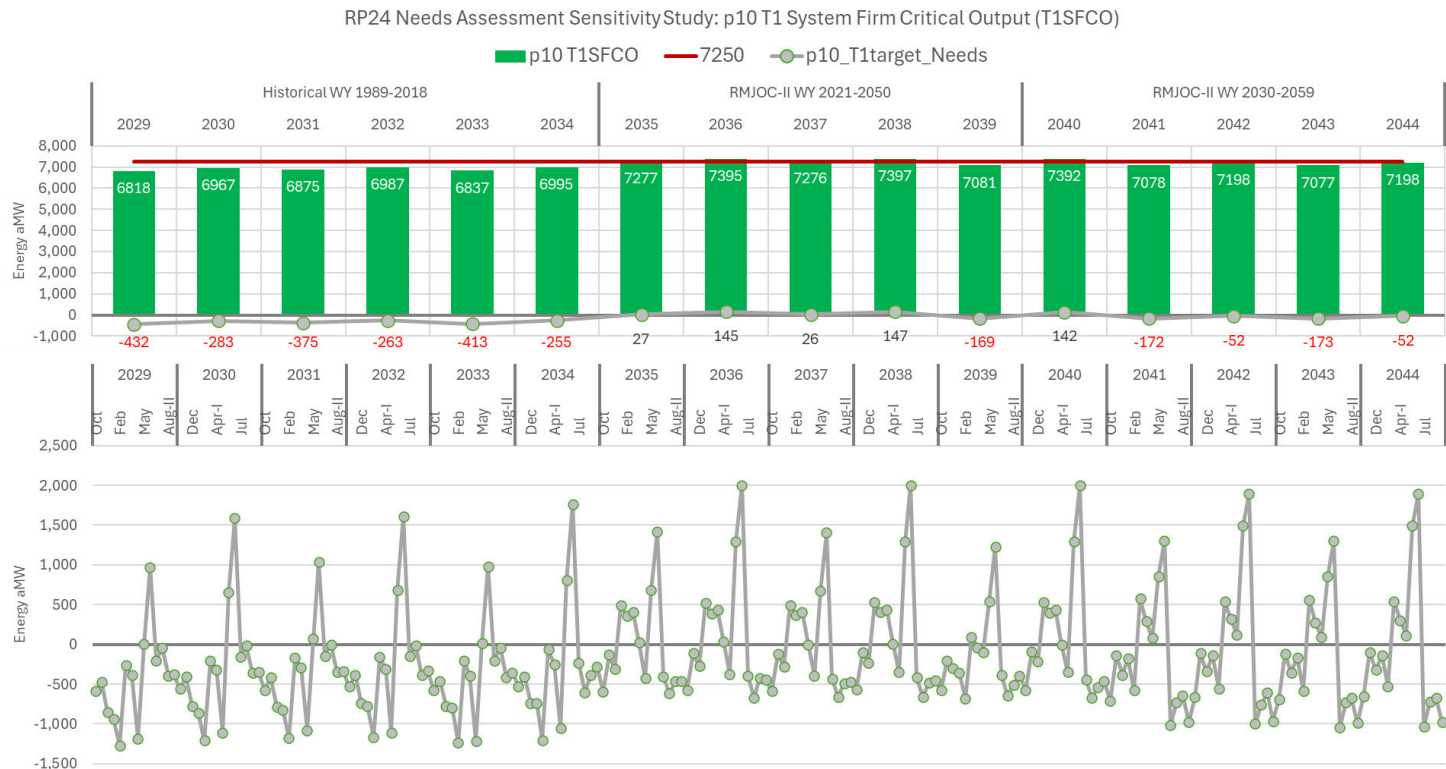
All values are for 2045. Nameplate capacities of supply-side resources represent maximum output under optimal conditions. Annual aMW output of resources such as solar and wind are substantially less than nameplate capacity. Capacity value for non-dispatchable DR is sum of max. capacity across all products.

Tier 1 augmentation

- This sensitivity grows the T1 System Firm Critical Output (T1SFCO) to **7250 annual aMW** shaped to reflect **forecasted hourly shape of T1 obligations**, starting in **2029**
- Needs are modeled as average monthly energy needs at the **whole-system level** (no distinction between SWEDE and Mid-C zones)
- **Only supply-side resources** are allowed to contribute to the growth in T1SFCO
- **Current results are preliminary: CGS uprate** is not yet in the model. We expect to repeat this analysis when those inputs become available.

T1SFCO vs Target Augmentation

- Annualized view of output (top) masks variation at monthly level (bottom)
- Fluctuations in resource capability due to CGS refueling, system operations, and streamflow sets over 20-yr study horizon

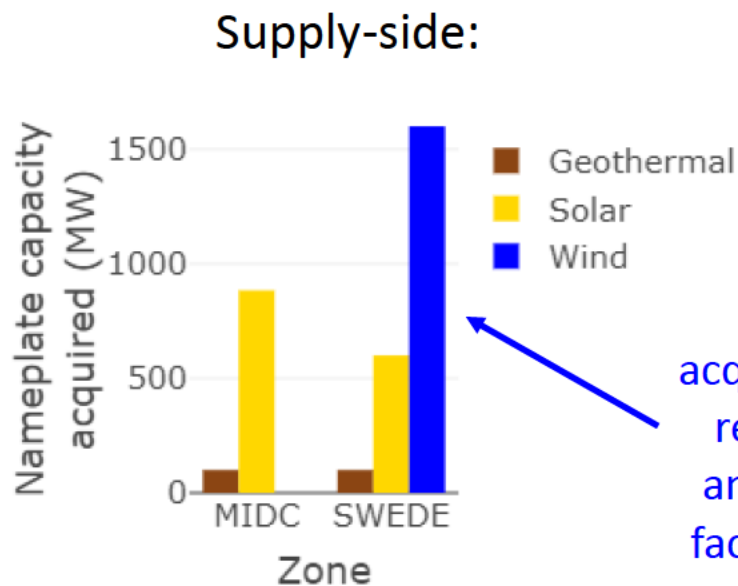


Tier 1 augmentation – Key takeaways

- Meeting T1 load exclusively with supply-side resources requires very substantial acquisitions:
 - P10 needs in the tightest month drive acquisitions
 - Generation greatly exceeds needs most of the time
- Augmentation is achieved with wind, solar, and geothermal power
- In the least-cost portfolio, most energy is generated in the SWEDE region

T1 augmentation: Resource acquisitions

We did not allow EE, DR, or market purchases to contribute to the T1 augmentation



Large wind acquisitions in SWEDE reflect lower costs and higher capacity factors in that region compared to Mid-C

Natural Gas Assessment

- Consistent with the previous resource program, we are not including natural gas (NG) resources as options directly in the solver.
- The diversity of carbon policies across the BPA service territory complicate the modeling of natural gas in the optimization process. This would significantly expand the scope of the resource program modeling as multiple approaches would be needed for each scenario and sensitivity.
- Modeling natural gas also includes other technical challenges that led to the decision to not include it in the model.
 - Incorporation of NG price risk modeling, this model has caused significant delays and errors in other applications
 - Uncertainty around costs and availability of firm fuel
 - Uncertainty around costs and key characteristics of transitioning NG resources to clean fuels (H2 / biofuels)
- The exclusion of NG resources from the solver does not preclude BPA from acquiring any resource necessary to meet needs at the lowest cost / in a cost-effective manner, as outlined in the Northwest Power Act and consistent with sound utility practice.
- We will gather feedback on NG modeling for RP26 and determine direction for future modeling.

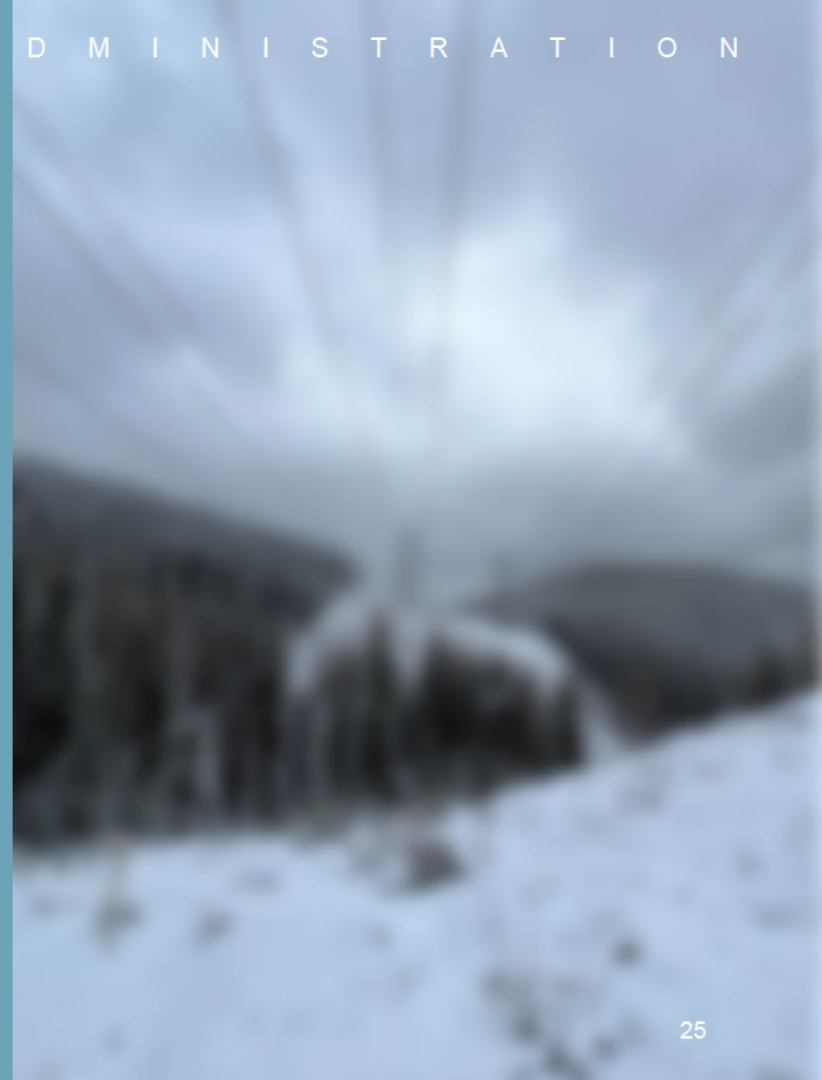
Natural Gas Assessment: Key takeaways

- Including new NG would not change results or lower portfolio costs for the base case or any associated sensitivities. This depends on the following assumptions:
 - A new NG plant built for BPA could not be online before 2035 and would only serve as a bridge resource until 2045
 - Carbon emission costs are considered
 - SMRs beginning operation in 2035 are available and eligible for Inflation Reduction Act tax credits, will not cost substantially more than baseline estimates, and will remain online for 60 years
- Using the above assumptions, the NG assessment for RP24 tests whether the solver would have selected a new NG resource.

Resource Acquisition Process

Eric Federovitch

Manager, Long Term Sales and Purchases



BPA Power Services and Resource Acquisition

- BPA is defining its processes for potential resource acquisitions, and refining existing ones related to assessing and implementing cost-effective updates of existing FCRPS projects
- We continue to explore the possibility of solidifying a resource acquisition commitment before new long-term power sales contracts are signed, as well as opportunities to modernize 6(c) procedures and policy in collaboration with the Northwest Power and Conservation Council
- RP26 will provide information on the type, timing, and quantity of potential resource solutions which may be used to inform a formal resource solicitation process

Acquiring Major Resources – Summary

- Provider of Choice process and Resource Programs inform major resource acquisition decisions, but are not the decision making processes
- BPA is aware of and considering potential approaches to acquire resources on the timeline needed to meet customer obligations post-2028
 - BPA and Council staff are reviewing the current Section 6(c) Policy and considering revisions to update the Policy consistent with the NW Power Act and efficient acquisition practices
 - BPA has benchmarked processes of other utilities to gather best practices and insights to incorporate into process for potential resource acquisitions
- Continuing to explore cost effective opportunities e.g. FCRPS uprates, cost-effective market purchases and minor supply-side acquisitions, experimental 6(d) acquisitions
- Under development project plan to include: Commercial solicitation and contracting, legal/6(c), environmental compliance, transmission considerations, financial

Questions and Discussion



Appendix

Resource Solutions



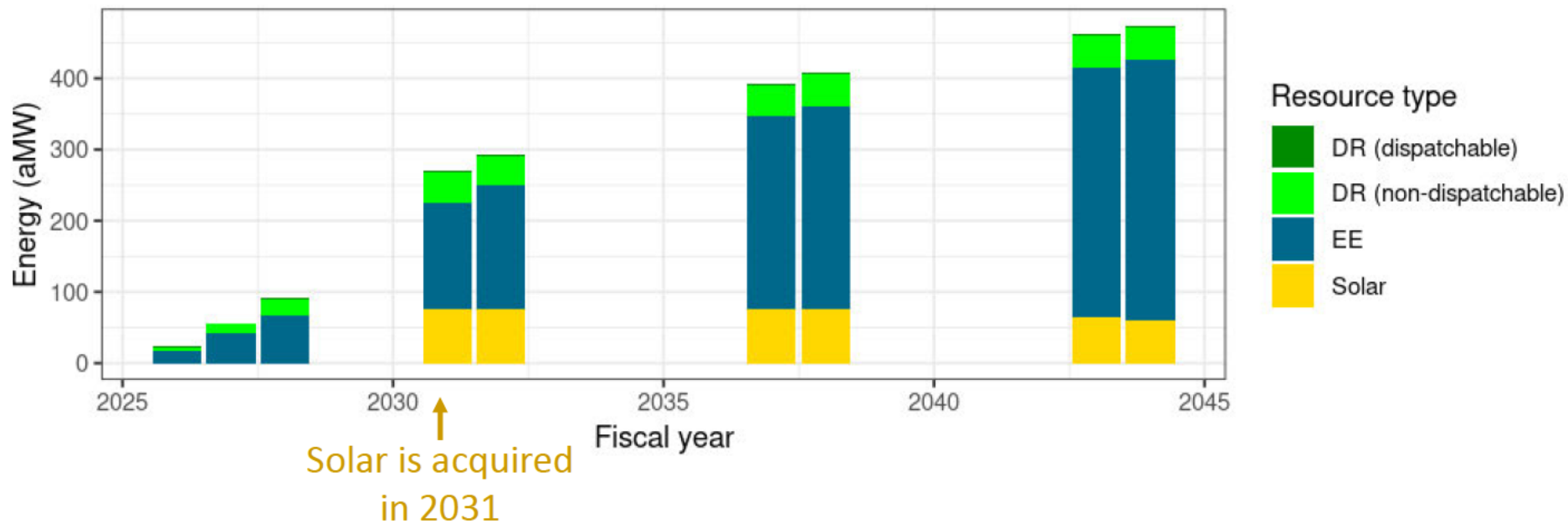
Base scenario: EE and DR

- Non-dispatchable DR programs acquired:
 - Residential Time of Use (TOU) Pricing
 - Utility Demand Voltage Reduction (DVR)
- Dispatchable DR programs acquired:
 - Commercial, industrial, and residential Critical Peak Pricing (CPP)
- EE achieved by 2045:
 - Total: **564 aMW**
 - Serving BPA load: **395 aMW***
- More in-depth EE + DR analysis to come

*About 70% of the total EE achieved by BPA reduces the BPA load obligation. The remainder reduces customer obligations. The percentages vary by EE measure and by customer, but for modeling purposes, we assume 70% for all EE programs.

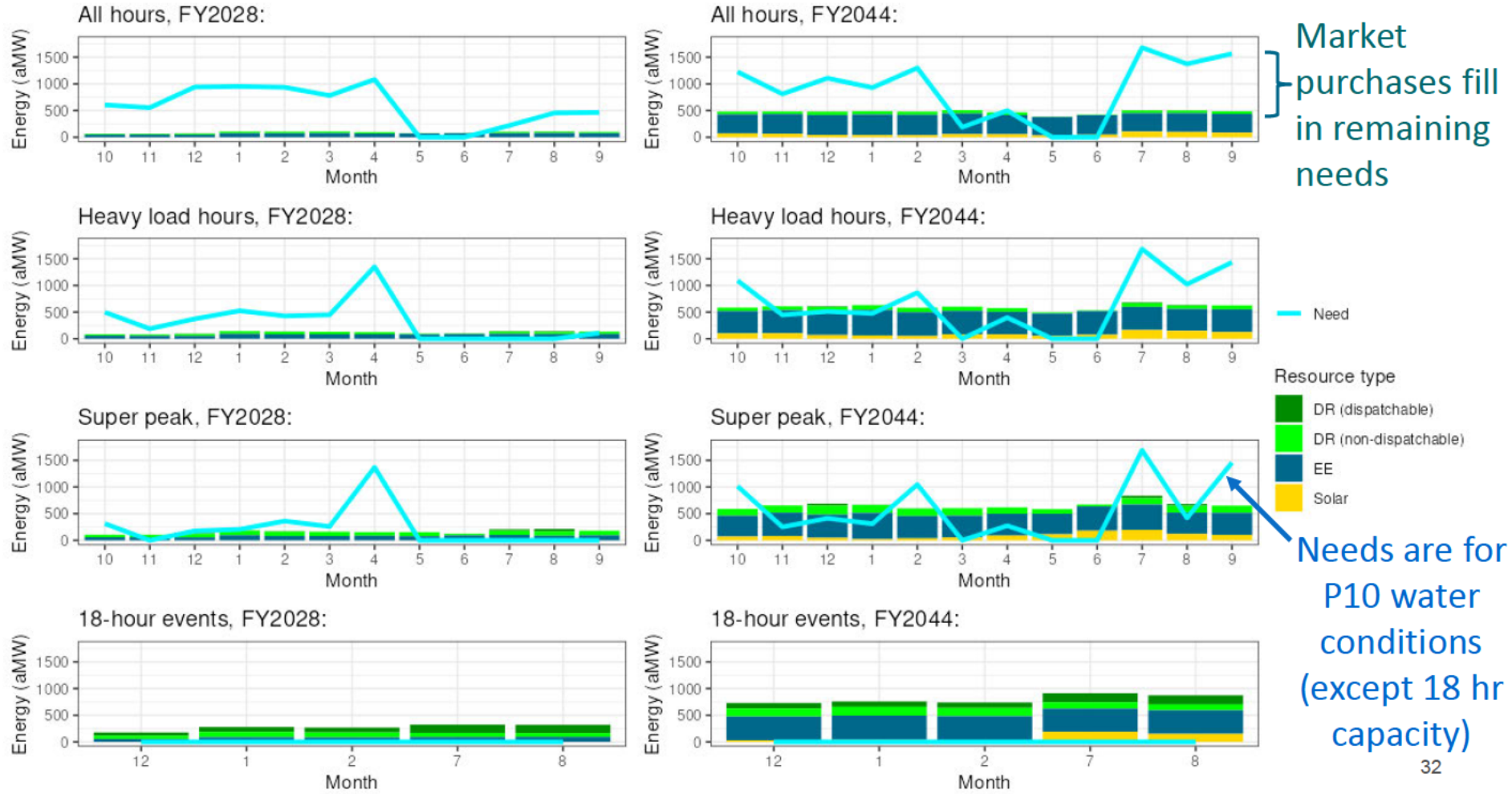
Base scenario: Mid-C annual aMW

EE and DR programs are started in 2026 and ramp up over time



EE aMW shown is the portion serving BPA load. Total EE acquired in Mid-C is 30% higher.

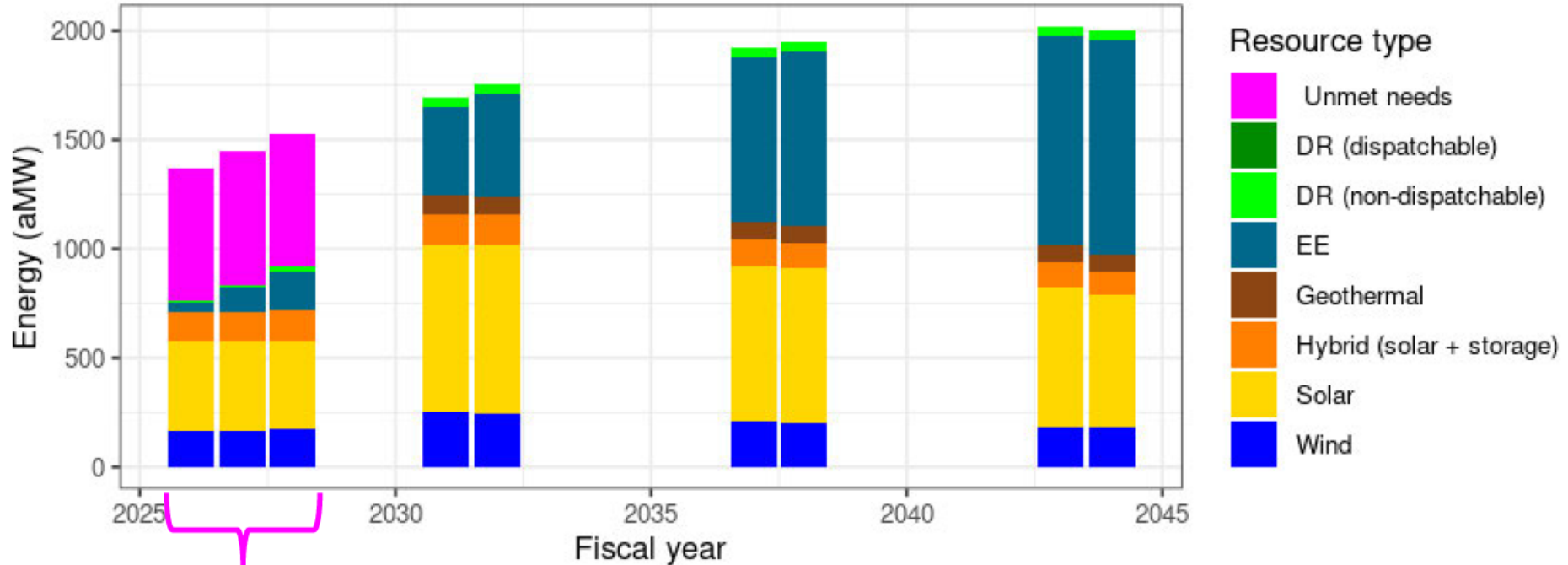
Base scenario, Mid-C needs and resource contributions:



Market limits sensitivities: Key takeaways

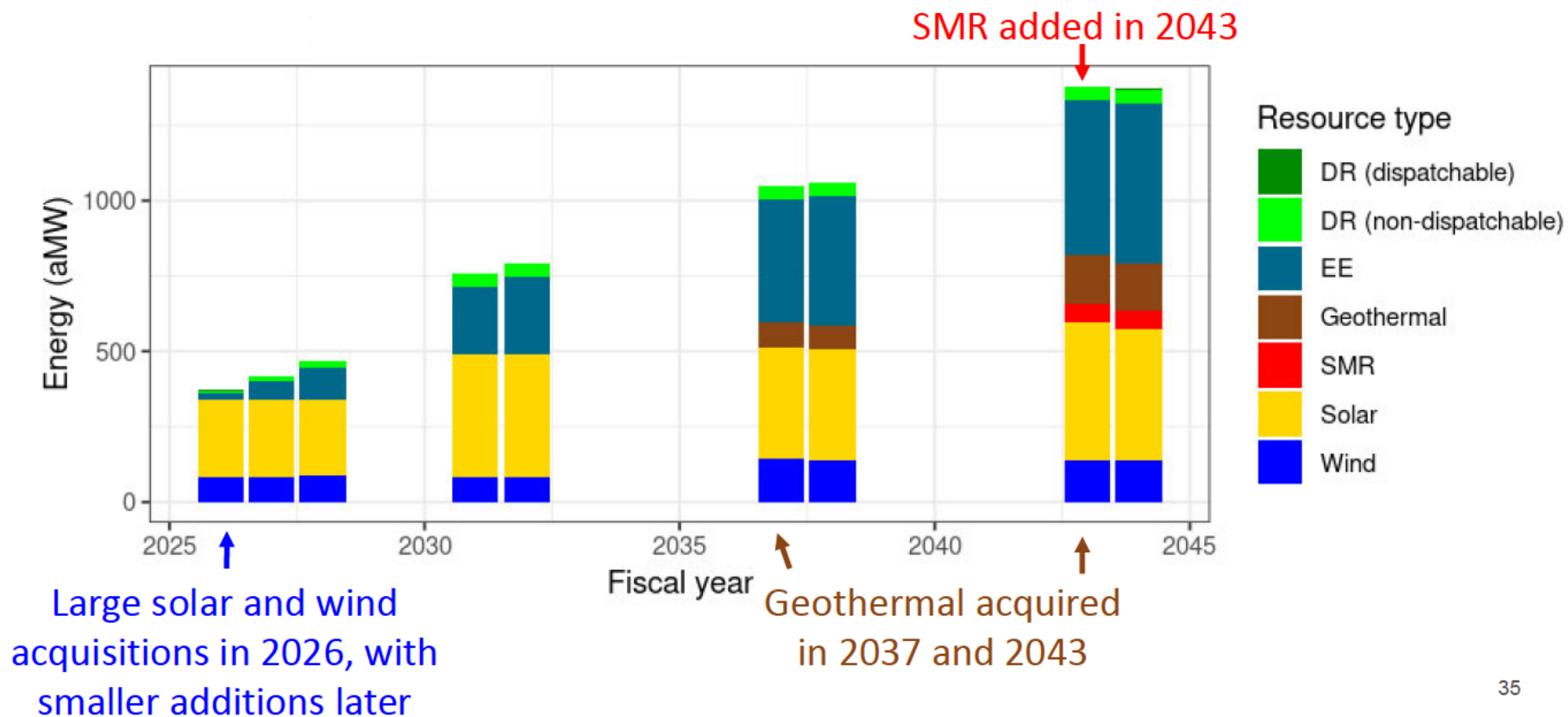
- Needs in 2026-2028 have a strong influence on results
 - Meeting needs in winter and April in this period requires large market purchases (or resources not currently in the model)
- Resource acquisitions are driven primarily by flat energy needs
- Market purchases are replaced primarily with solar and wind

'No market' sensitivity: Mid-C annual aMW

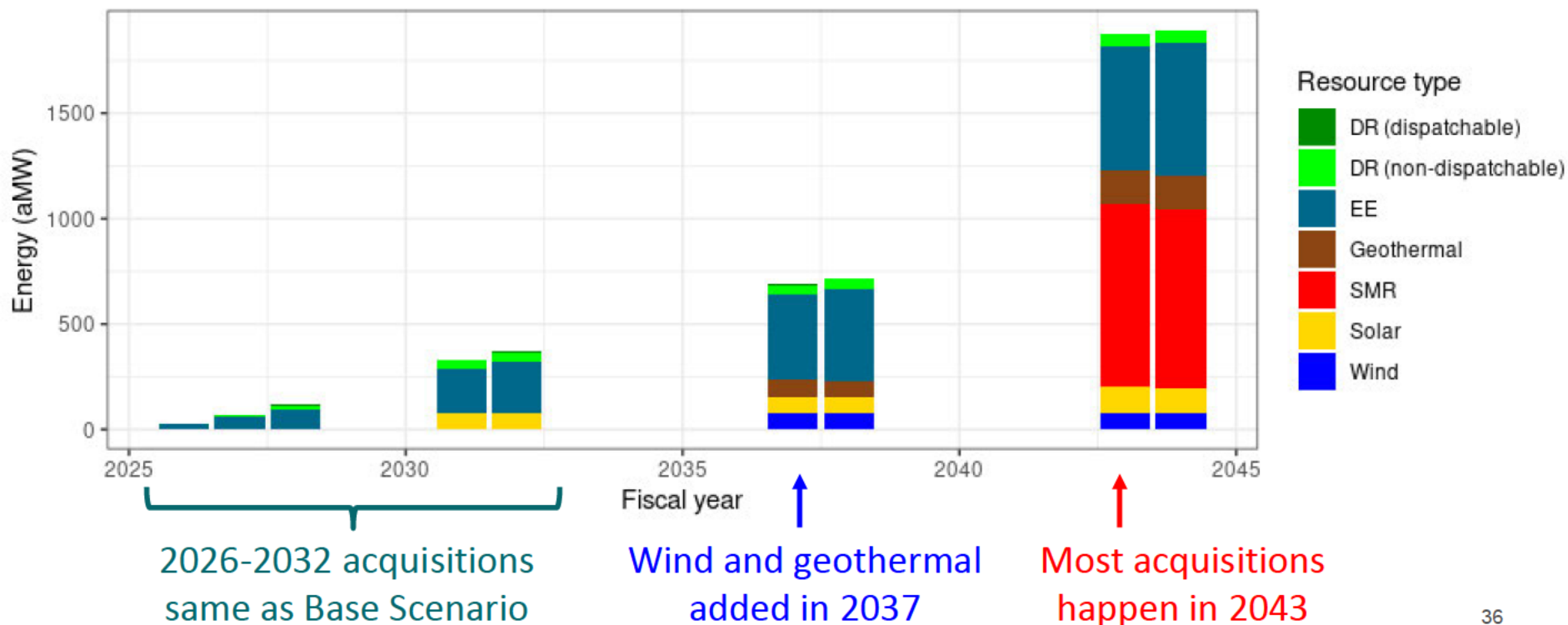


Months without enough resources to meet needs: Nov – Feb and April

'Reducing market purchases to 0' sensitivity: Mid-C annual aMW

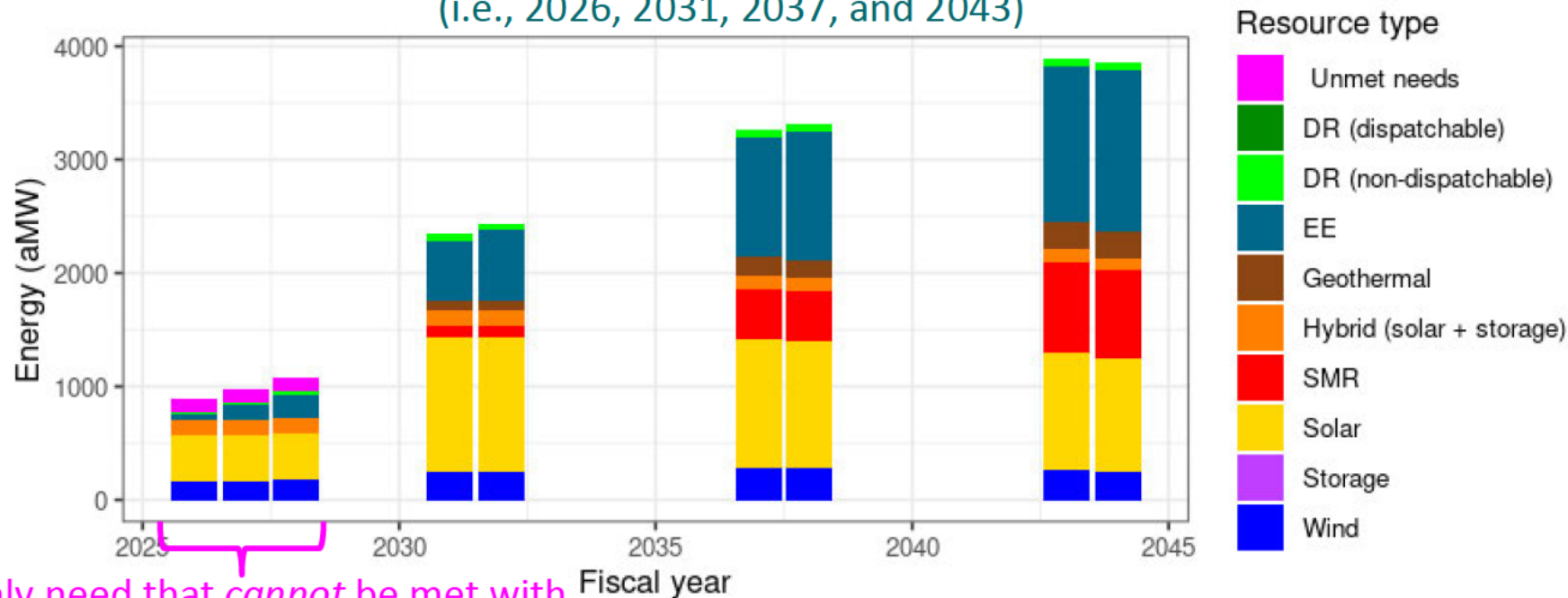


Medium load adder: Mid-C annual aMW



High load adder: Mid-C annual aMW

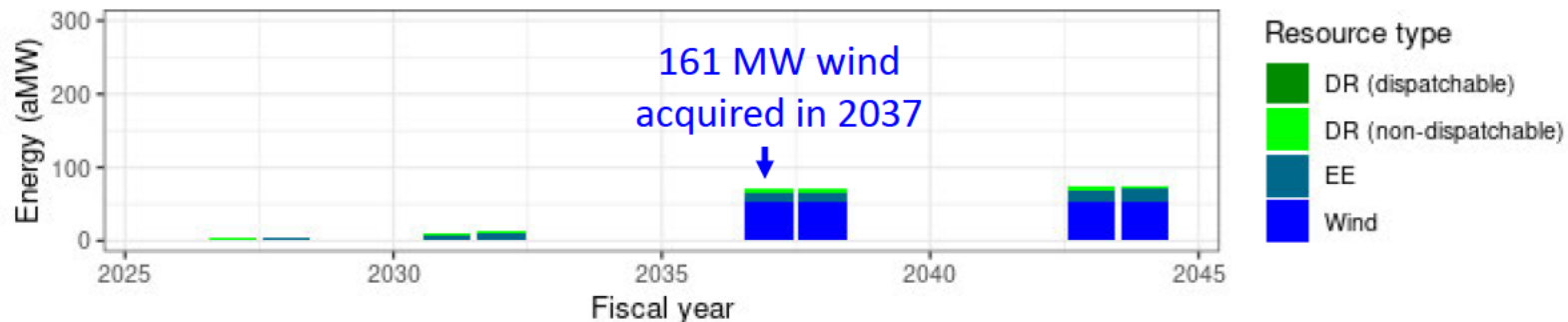
New, large acquisitions made in every available year
(i.e., 2026, 2031, 2037, and 2043)



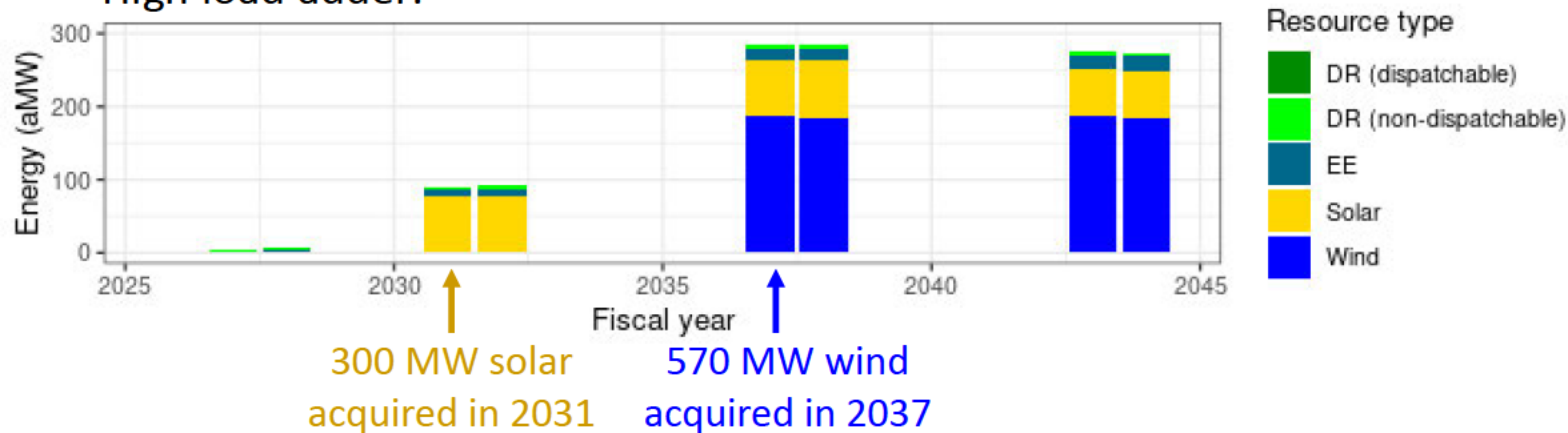
Only need that *cannot* be met with
resources in the model: Apr '28 HLH

Load adders: SWEDE annual aMW

Medium load adder:

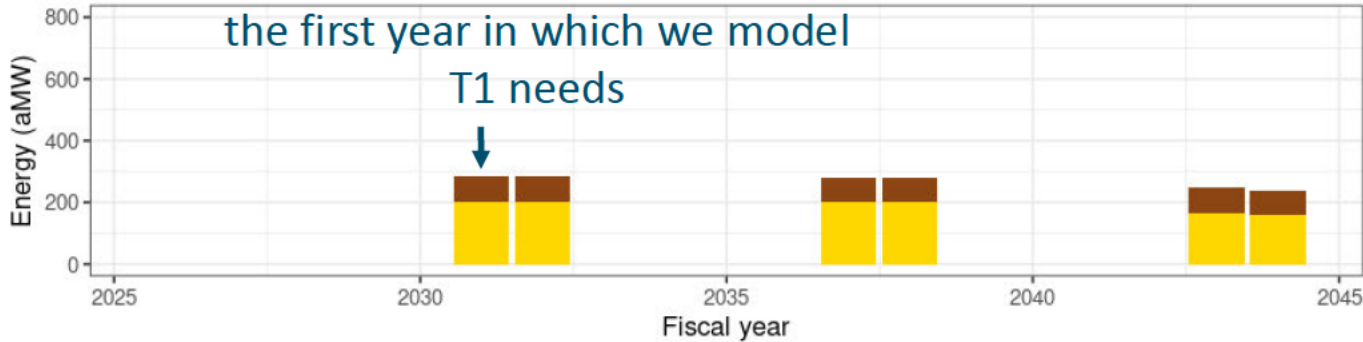


High load adder:

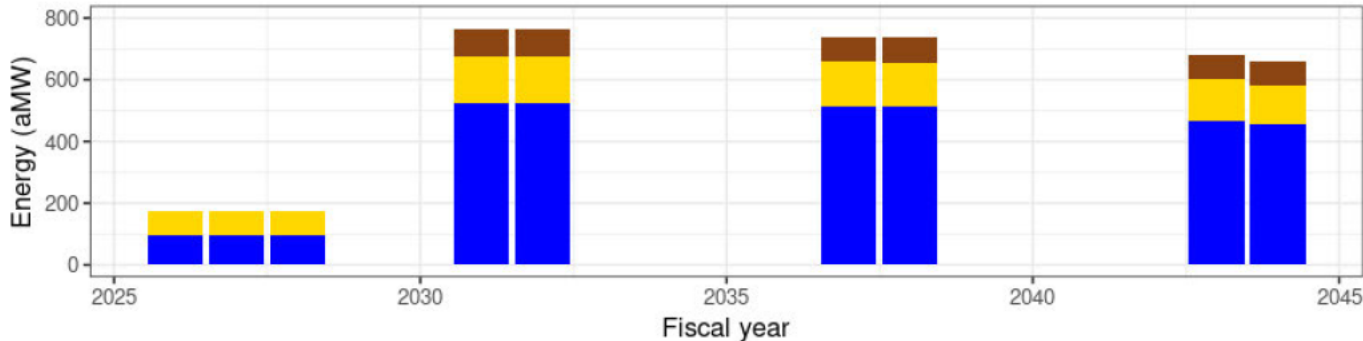


Tier 1 augmentation: annual aMW

MIDC: Resources all acquired by 2031,
the first year in which we model



SWEDE:



Most of the energy is
generated in SWEDE

Tier 1 augmentation: monthly aMW

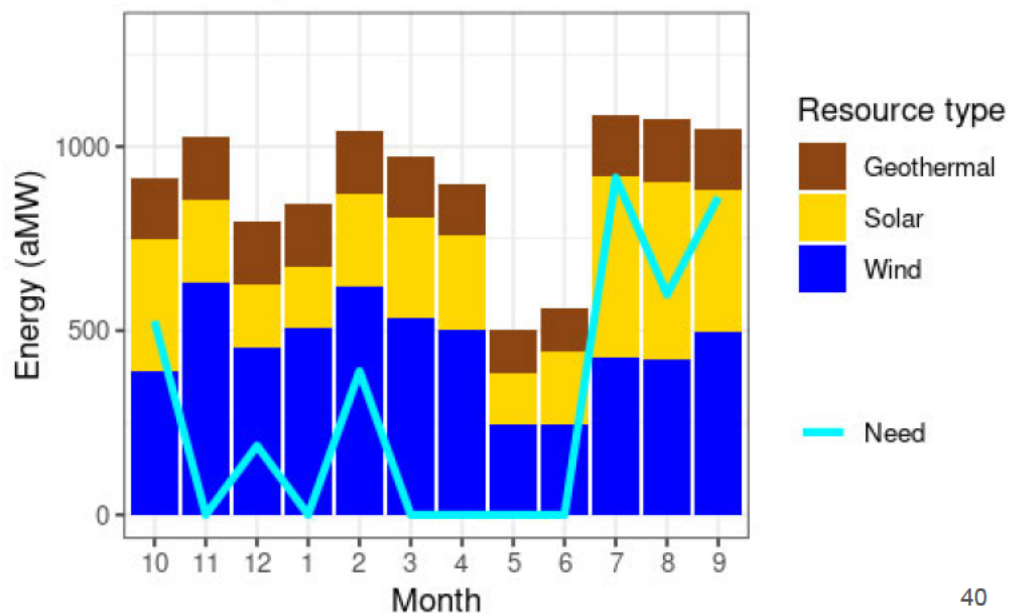
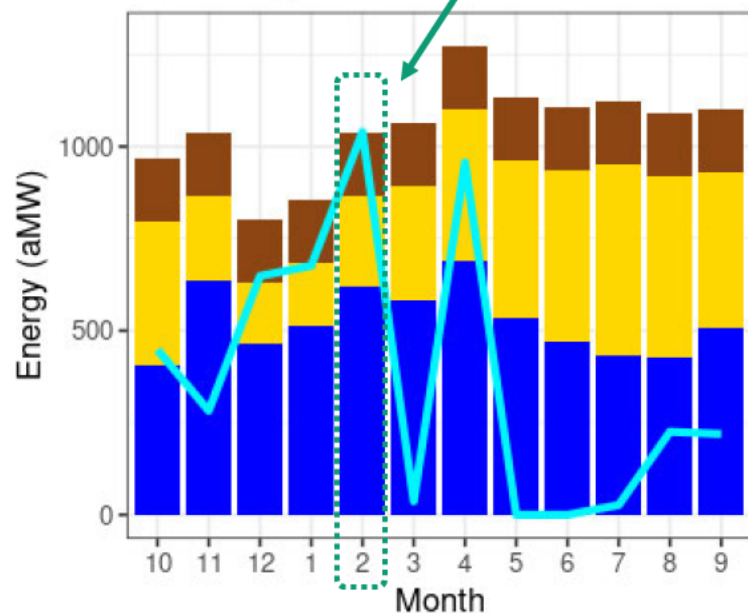
In most months, generation is much greater than needs, even under P10 conditions

Solver is building to meet

All hours, FY2031:

February 2031 need

All hours, FY2044:



Natural Gas Assessment

	Base scenario	Market limits				High Mkt Price	Loads	
		Reduce 25%	Reduce 50%	Reduce 50% All	Path to 0		Med Load	High Load
2029-2034								
*2035-2040								
2041-2045								

*2035 is the earliest date we've assumed BPA could have a new resource online considering EIS, interconnection, and other necessary processes.

	Not Selected
	Likely Selected if Available
	Likely Selected

If BPA could get a NG resource online sooner, temporarily acquire output from an existing plant, or invest in NG resources that transition to zero emissions (through clean fuels or carbon sequestration), NG resources may help reduce costs of meeting needs under more sensitivities.

BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c))
Emergency Order: Transalta)
Centralia Generation LLC)
_____)

Order No. 202-25-11

Motion to Intervene, Motion for Clarification, and Requests for Rehearing and Stay
of Sierra Club, NW Energy Coalition, Washington Conservation Action, Climate
Solutions, Public Citizen, and Environmental Defense Fund
(collectively, “Public Interest Organizations” or “PIOs”)

Exhibit 1-95:
Centralia Summary by TransAlta



Facts & Figures

Location:	Centralia, WA
Legacy Fuel:	Coal
Capacity (MW):	670
Ownership:	100%
Operator:	Yes
First on-stream:	1971
Revenue Source:	LTC/Merchant
Builder:	No

Facts & Figures

Contract Expiry:

Unit 1 - 2020; Unit 2 - 2025

[Back](#)

Centralia

On December 31, 2020, TransAlta retired Unit 1 of our Centralia facility, decreasing the facility's capacity to 670 MW. Throughout its lifetime, Unit 1 provided a total net generation of just over 176,660,518 MWh with an average availability of 85.66 per cent. Unit 2 of the facility is set to retire at the end of 2025, as part of TransAlta's transition to a 100 per cent clean electricity future.

In **December 2025**, TransAlta Corporation's subsidiary, TransAlta Centralia Generation LLC, received an order (the Order) from the United States Department of Energy. The Order mandates that Centralia Unit 2 in Washington State, remain available for operation for a period of 90 days, until March 16, 2026. TransAlta is currently evaluating the Order and will work with the state and federal governments in relation thereto. The coal-to-gas conversion project, announced on December 9, 2025, remains a priority for TransAlta. Further information regarding the Order will be provided as it becomes available in due course.

The reliable and steady supply of power from the Centralia Coal Plant is essential for keeping the west-coast electrical grid stable. The facility is a merchant plant, which means that costs such as environmental upgrades cannot be passed on to customers. TransAlta has invested more than US\$300 million in pollution control technology at Centralia Plant, including scrubbers and low nitrogen dioxide burners. Today, the facility is one of the cleanest coal-fired power plants in North America.

Fuel for Centralia Plant is delivered by train from the Powder River Basin in the U.S. Midwest. The plant's coal unloading facility is considered one of the most efficient and environmentally friendly in North America.

In preparation for the retirement of Unit 1 in 2020, and the upcoming retirement of Unit 2 in 2025, TransAlta has invested \$55 million USD to support energy efficiency, economic and community development and education and retraining initiatives in Washington

State, \$20 million USD of which is dedicated to the *Economic and Community Development Board*, which will fund education, retraining, economic development and community enhancement for those impacted by the units retirement.

Coal Combustion Residuals (CCR) rule compliance data and information

TransAlta is committed to providing information to the community about our facilities. The information below is intended to satisfy the requirement under the *CCR Rule 40 CFR 257.107* to maintain a publicly accessible internet site (CCR site) containing the required information. The required information will be posted when it is accomplished and is available.

Location restrictions

Unstable areas

Operating criteria

CCR fugitive dust control plan

Run-on and run-off control plan

Annual fugitive dust control report

Annual CCR Fugitive Dust Control Report – 2016

Annual CCR Fugitive Dust Control Report – 2017

Annual CCR Fugitive Dust Control Report – 2018

Annual CCR Fugitive Dust Control Report – 2019

Annual CCR Fugitive Dust Control Report – 2020

Annual CCR Fugitive Dust Control Report – 2021

Annual CCR Fugitive Dust Control Report – 2022

Annual CCR Fugitive Dust Control Report – 2023

Annual CCR Fugitive Dust Control Report – 2024

Annual CCR Fugitive Dust Control Report – 2025

Annual engineering inspection reports

CCR Annual Inspection January 11, 2016

CCR Annual Inspection January 5, 2017

CCR Annual Inspection January 4, 2018

CCR Annual Inspection January 3, 2019

CCR Annual Inspection January 7, 2020

CCR Annual Inspection January 6, 2021

CCR Annual Inspection January 5, 2022

CCR Annual Inspection January 5, 2023

CCR Annual Inspection January 5, 2024

CCR Annual Inspection January 15, 2025

Groundwater monitoring and corrective action

Annual groundwater monitoring and corrective action Report – 2024

Annual groundwater monitoring and corrective action Report – 2023

Annual groundwater monitoring and corrective action Report – 2022

Annual groundwater monitoring and corrective action Report – 2021

Annual groundwater monitoring and corrective action Report – 2020

Annual groundwater monitoring and corrective action Report – 2019

Alternative Source Demonstration Nov-2-2018

Annual groundwater monitoring and corrective action Report – 2018

Annual groundwater monitoring and corrective action Report – 2017

Addendum to 2017 Annual CCR Groundwater Monitoring Report

Groundwater monitoring system certification

Statistical method certification

Notification of assessment monitoring program

Notification of return to detection monitoring program

Notification of Appendix IV exceedances

Notification of corrective measures assessment

Corrective measures assessment

Semi-annual corrective action report

Notification of completion of corrective action

Closure and post-closure care

Closure plan

Time extensions for initiating closure

Time extensions for completing closure

Notification of intent to initiate closure

Notification of completion of closure

Notification of intent to comply with alternative closure requirements

Annual progress reports for alternative closure

Notification recording a notation on property deed

Post-closure care plan

Notification of completion of post-closure care

BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c))
Emergency Order: Transalta)
Centralia Generation LLC)
_____)

Order No. 202-25-11

Motion to Intervene, Motion for Clarification, and Requests for Rehearing and Stay
of Sierra Club, NW Energy Coalition, Washington Conservation Action, Climate
Solutions, Public Citizen, and Environmental Defense Fund
(collectively, “Public Interest Organizations” or “PIOs”)

Exhibit 1-96:
MIT Article

Ask MIT Climate

Have a question?

[Ask us!](#)

ASK MIT CLIMATE

Why does burning coal generate more CO₂ than oil or gas?



Listen with [Speechify](#).

0:00

2:43



Coal contains more carbon than oil or gas. When we burn these fuels, the higher amount of carbon in coal reacts to form CO₂,



by MIT Climate Portal Writing Team



featuring guest expert
Gregory Stephanopoulos, MIT
Professor of Chemical
Engineering

while a higher proportion of hydrogen in oil and gas causes them to form H₂O along with CO₂.



and guest expert Shuhei Ono,
MIT Professor of
Geochemistry



Climate
101

Explore

MIT
Action

carbon-based molecules—so fossil fuels, which are made of once-living things, are as well. But coal “has a lot more carbon in it” than oil or gas, says Gregory Stephanopoulos, an MIT professor of chemical engineering. The “carbon-intensity” of each fuel determines how much CO₂, or carbon dioxide, each produces.

Coal, oil, and gas were created over millennia as buried organic material decayed.

Today’s coal began as plants growing in and near swamps millions of years ago, which died and became covered with water. Cut off from oxygen, the plants slowly decomposed, and bacteria and chemicals in the water reacted to create a substance called peat.

As geology changed, water and sediment covered the peat, burying it under layers of earth and minerals, and applying pressure.

“When organic matter is buried in sediments, it gets cooked at higher temperatures,” says Shuhei Ono, an MIT professor of geochemistry. This heat aided chemical reactions and broke down molecules, pushing out hydrogen and oxygen and leaving



MIT Department of Chemical
Engineering



MIT Department of Earth
Atmospheric and Planetary
Sciences

More Resources for Learning

[U.S. Energy Information Administration: "How much carbon dioxide is produced when different fuels are burned?"](#)

[U.S. Energy Information Administration: "Coal explained"](#)

[Smithsonian Ocean Portal: "What are fossil fuels?"](#)

[University of Calgary: "Coal formation"](#)

behind higher percentages of carbon.

Thus, peat became coal.¹

Generally, the more pressure and heat coal experiences as it forms, the more carbon it contains—from younger “lignite” coal (about 25 percent carbon) to “anthracite” coal (up to 97 percent carbon).

Oil and gas formed not in swamps, but in the ocean, when small plants and animals called plankton died and sank to the ocean floor, mixing with other organic material. Like the peat in swamps, this material was buried and exposed to pressure and heat under the ocean floor, producing a material called kerogen. With increased temperature and pressure, the kerogen slowly lost its hydrogen atoms, shedding them first as long chains of carbon and hydrogen (oil), and finally as CH₄ (methane, or gas). Pure carbon is left underground, while the hydrogen-rich oil and gas can be extracted and burned as fuels.

In the end, says Ono, “methane contains only C-H bonds, and coals are [mostly] C-C. Oil is between the two.”

When humans burn any of these fossil fuels, the chemical reaction releases energy in the form of heat. “This is the energy we use for power generation or moving cars, and doing all the things that we do with fossil fuels,” says Stephanopoulos. As the fuels burn, oxygen in the air reacts either with carbon, forming CO₂, or with hydrogen, forming H₂O, or water vapor. When coal burns, its higher proportion of carbon molecules creates more CO₂ per unit of energy. For oil and gas, it’s “mainly the

[University of Calgary: "Oil formation"](#)



Topics

ATMOSPHERE

FOSSIL FUELS

hydrogens that will burn and generate energy, not the carbons,” Stephanopoulos says.

Though burning coal is more carbon-intensive, both oil and gas still produce climate-warming CO₂. And natural gas is largely made up of CH₄, a short-lived climate pollutant that warms the planet even more than CO₂.

Thank you to Juan Manuel Alfonso of Argentina for the question. You can submit your own question to Ask MIT Climate [here](#).

[Read more Ask MIT Climate](#)

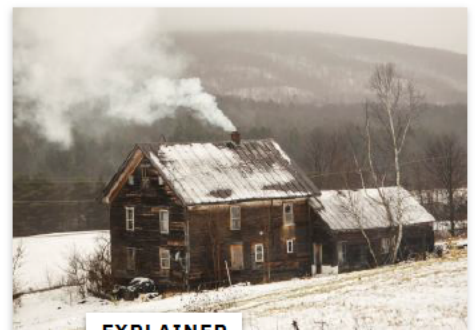
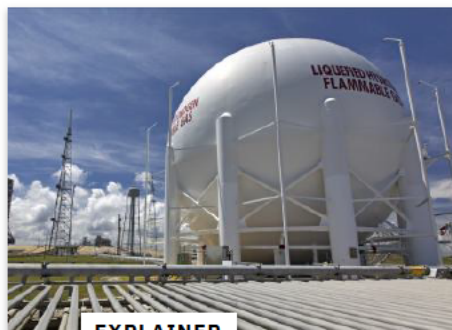
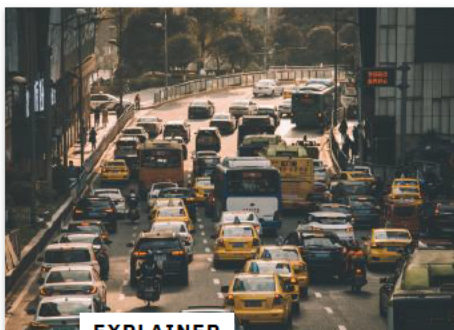
Creative Commons Attribution-NonCommercial-ShareAlike 4.0 International license (CC BY-NC-SA 4.0) [↗](#).

FOOTNOTES

¹ Coal formation also creates some natural gas, which is trapped in fractures in coal buried underground.

Keep exploring

Check out these related Explainers, written by scientists and experts from MIT and beyond.



Greenhouse Gases

Greenhouse gases are gases—like carbon dioxide, methane, and nitrous oxide—that keep the Earth warmer than it would be without them.

Hydrogen

Hydrogen is the most abundant chemical substance in the universe. It can be used as a fuel that does not produce greenhouse gases when burned.

Heating and Cooling

Heating and cooling is the biggest driver of energy use in homes and commercial buildings. Technology and building design can help keep us comfortable while reducing the impact of that energy use on the climate.

[VIEW ALL](#)

Related Pieces

What makes the climate of Venus so hot?

The planet's searing temperatures are sustained by a thick atmosphere full of carbon dioxide.

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BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c))
Emergency Order: Transalta)
Centralia Generation LLC)
_____)

Order No. 202-25-11

Motion to Intervene, Motion for Clarification, and Requests for Rehearing and Stay
of Sierra Club, NW Energy Coalition, Washington Conservation Action, Climate
Solutions, Public Citizen, and Environmental Defense Fund
(collectively, “Public Interest Organizations” or “PIOs”)

Exhibit 1-97:
WECC Explainer

What is the ODITY Threshold?

In planning, “one day in ten years” (ODITY) represents the maximum acceptable amount of time electricity generation can be at risk of being short of demand and still be considered adequately reliable.

How is the ODITY Threshold measured?

Many utilities incorporate the ODITY threshold into their long term, integrated resource planning methods by bringing it down to an annual level of temporal granularity. One day in 10 years, or 24 hours in 10 years, is often averaged to a maximum of 2.4 hours of risk allowed per year for a portfolio of resources to be considered sufficiently reliable.

WECC takes the ODITY maximum down to the hourly level to set thresholds in its probabilistic assessments of resource adequacy. This interpretation yields a threshold for each hour needing to demonstrate sufficient resource availability to meet demand 99.8% of the time.

Why does WECC use the ODITY threshold on each hour?

WECC chooses to look at the ODITY threshold for each hour rather than averaged over each year:

- To accurately account for risk;
- To study variability hour to hour; and
- To improve assumptions of import availability.

ODITY in Probabilistic Assessments: Accounting for Risk

WECC uses hourly shaped, bell curve probability distributions of demand next to those of energy availability by resource type to measure reliability.

For each hour, the distributions are compared to determine the amount of “overlap” in the upper tail of the demand distribution with the lower tail of the generation availability distribution. The amount of overlap and the probabilities associated with each percentile of the distributions can then calculate as a loss of load probability (LOLP). This is the cumulative probability associated with the overlap.

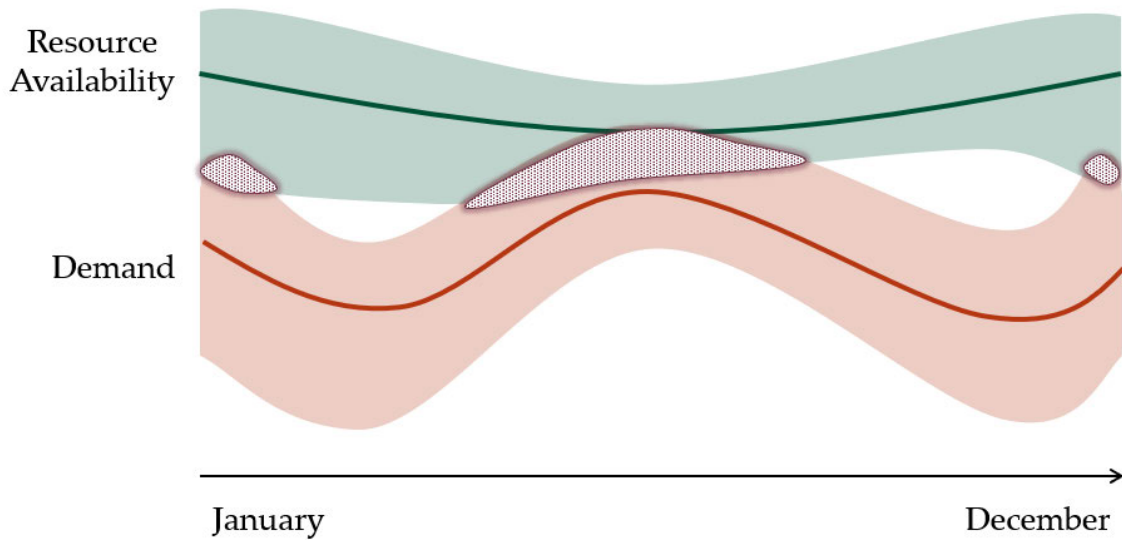


Figure 1: Annual Distribution Ranges of Demand and Resource Availability

If the probability of the resource availability falling below demand is greater than a certain threshold—in this case more than 0.02% for one of the hours—WECC notes there is a reliability shortfall in that area for that hour. A reliability threshold reserve margin (in megawatts) can be calculated to determine the shortfall in need of amelioration to maintain a level of LOLP at or less than the threshold.

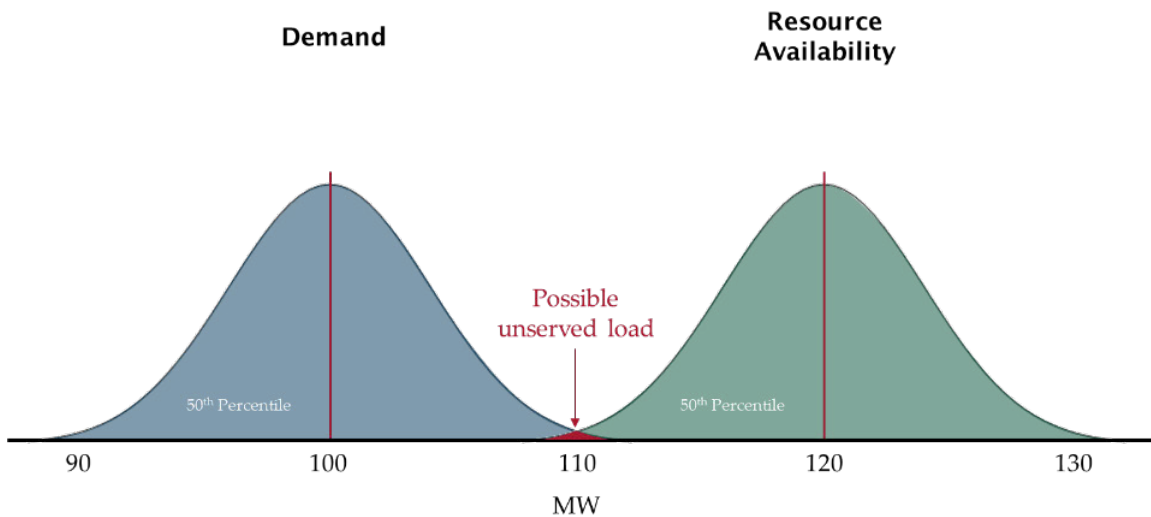


Figure 2: A Single Hour's View of the Probability Distributions of Demand and Resource Availability

Hourly Variability

Over 80% of new electricity capacity are renewables.¹ Concurrently, climate change is contributing to record peak demand by skewing the probability of previously rare weather, like widespread and long-lasting heat dome events.

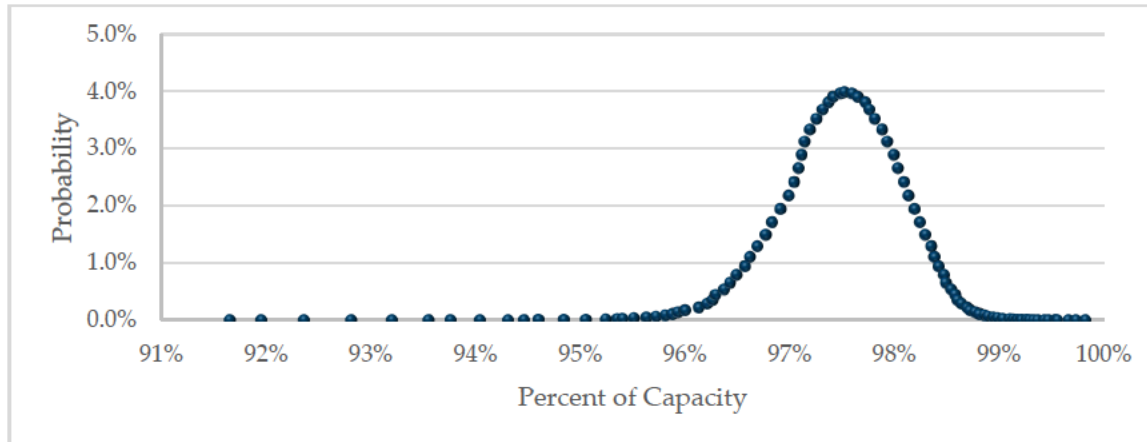


Figure 3:

Baseload Availability Probability Distribution Example

Historically, electricity demand peaked on weekdays in the early evenings when many people get home from work. This timing typically coincides with a setting sun. So, just as electricity system operators are looking for resource availability to ramp up generation to meet the spiking demand, at least the solar resources' availabilities are dropping.

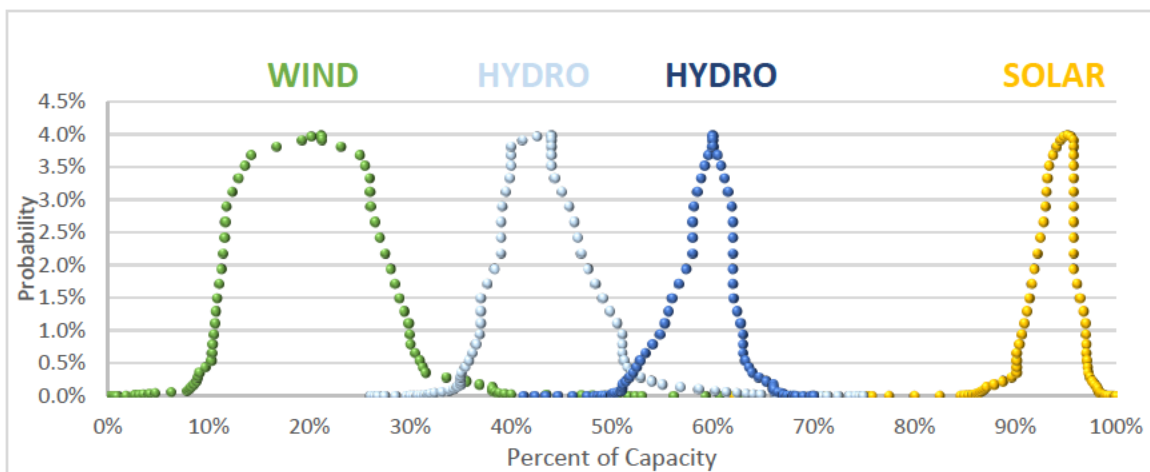


Figure 4: Renewables' Availability Probability Distributions Example

To combat the ramping risk, many planners are turning to long-term energy storage, either via hydro reservoirs, utility-scale batteries, or the incorporation of other new technologies like hydrogen, as well

¹ Some good news on energy — The New York Times (nytimes.com) October 25, 2022

as the traditional use of natural gas peaker plants. The combinations of new and conventional resource types make new shapes of availability.

WECC is interested in looking at every hour so this aspect of a changing system is regularly analyzed to ensure reliability and spot potential issues years in advance.

Imports' Availability Assumptions

The West's system is large, and its diversity increases reliability because Balancing Authority Areas (BAA) can often rely on each other for imports. In planning, sometimes a limit is set for how many megawatts of imports will be available.

Since WECC collects loads and resources information from all of the BAAs throughout the West, and conducts probabilistic assessments of availability and demand, WECC can see when and where imports may not be sufficient to cover shortfalls of internal availability to meet demand.

Doing this analysis at the hourly level provides greater insights by identifying specific situational risk.

Conclusion

There are many ways to perform probabilistic studies, each with its strengths and weaknesses. The tool used to perform the probabilistic calculations depends on the system and the desired output that is being analyzed. In the Western Interconnection, a system that is geographically diverse and depends on transfer capabilities, WECC developed the Multiple Area Variable Resource Integration Convolution (MAVRIC) model to enhance its probabilistic capabilities. Using convolution techniques, Monte-Carlo simulations, and the ability to use transfers dynamically, MAVRIC can better model the overall reliability of the Western Interconnection while maintaining adequate run-time and computing capabilities.

BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c))
Emergency Order: Transalta)
Centralia Generation LLC)
_____)

Order No. 202-25-11

Motion to Intervene, Motion for Clarification, and Requests for Rehearing and Stay
of Sierra Club, NW Energy Coalition, Washington Conservation Action, Climate
Solutions, Public Citizen, and Environmental Defense Fund
(collectively, “Public Interest Organizations” or “PIOs”)

Exhibit 1-98:
NERC Emergency Operations

A. Introduction

1. **Title:** **Emergency Operations**
2. **Number:** **EOP-011-4**
3. **Purpose:** To address the effects of operating Emergencies by ensuring each Transmission Operator and Balancing Authority has developed plan(s) to mitigate operating Emergencies and that those plans are implemented and coordinated within the Reliability Coordinator Area as specified within the requirements.
4. **Applicability:**
 - 4.1. **Functional Entities:**
 - 4.1.1 Balancing Authority
 - 4.1.2 Reliability Coordinator
 - 4.1.3 Transmission Operator
 - 4.1.4 Distribution Provider identified in the Transmission Operator's Operating Plan(s) to mitigate operating Emergencies in its Transmission Operator Area
 - 4.1.5 UFLS-Only Distribution Provider identified in the Transmission Operator's Operating Plan(s) to mitigate operating Emergencies in its Transmission Operator Area
 - 4.1.6 Transmission Owner identified in the Transmission Operator's Operating Plan(s) to mitigate operating Emergencies in its Transmission Operator Area
5. **Effective Date:** See Implementation Plan for Project 2021-07. As provided therein, each Distribution Provider, UFLS-Only Distribution Provider, and Transmission Owner that receives notification from the Transmission Operator that it is required to assist in the mitigation of operating Emergencies in the Transmission Operator Area under Requirement R7 shall become compliant with Requirement R8 within 30 calendar months of the notification.

B. Requirements and Measures

- R1.** Each Transmission Operator shall develop, maintain, and implement one or more Reliability Coordinator-reviewed Operating Plan(s) to mitigate operating Emergencies in its Transmission Operator Area. The Operating Plan(s) shall include the following, as applicable: *[Violation Risk Factor: High] [Time Horizon: Real-Time Operations, Operations Planning, Long-term Planning]*
- 1.1.** Roles and responsibilities for activating the Operating Plan(s);
 - 1.2.** Processes to prepare for and mitigate Emergencies including:
 - 1.2.1.** Notification to its Reliability Coordinator, to include current and projected conditions, when experiencing an operating Emergency;
 - 1.2.2.** Cancellation or recall of Transmission and generation outages;
 - 1.2.3.** Transmission system reconfiguration;
 - 1.2.4.** Redispatch of generation request;
 - 1.2.5.** Operator-controlled manual Load shed, undervoltage load shed (UVLS), or underfrequency load shed (UFLS) during an Emergency that accounts for each of the following:
 - 1.2.5.1.** Provisions for manual Load shedding capable of being implemented in a timeframe adequate for mitigating the Emergency;
 - 1.2.5.2.** Provisions to minimize the overlap of circuits that are designated for manual Load shed, UVLS, or UFLS and circuits that serve designated critical loads which are essential to the reliability of the BES;
 - 1.2.5.3.** Provisions to minimize the overlap of circuits that are designated for manual Load shed and circuits that are utilized for UFLS or UVLS;
 - 1.2.5.4.** Provisions for limiting the utilization of UFLS or UVLS circuits for manual Load shed to situations where warranted by system conditions;
 - 1.2.5.5.** Provisions for the identification and prioritization of designated critical natural gas infrastructure loads which are essential to the reliability of the BES as defined by the Applicable Entity; and
 - 1.2.6.** Provisions to determine reliability impacts of:
 - 1.2.6.1.** Cold weather conditions; and
 - 1.2.6.2.** Extreme weather conditions.
- M1.** Each Transmission Operator will have a dated Operating Plan(s) developed in accordance with Requirement R1 and reviewed by its Reliability Coordinator; evidence such as a review or revision history to indicate that the Operating Plan(s) has

been maintained; and will have as evidence, such as operator logs or other operating documentation, voice recordings or other communication documentation to show that its Operating Plan(s) was implemented for times when an Emergency has occurred, in accordance with Requirement R1.

- R2.** Each Balancing Authority shall develop, maintain, and implement one or more Reliability Coordinator-reviewed Operating Plan(s) to mitigate Capacity Emergencies and Energy Emergencies within its Balancing Authority Area. The Operating Plan(s) shall include the following, as applicable: *[Violation Risk Factor: High] [Time Horizon: Real-Time Operations, Operations Planning, Long-term Planning]*

2.1. Roles and responsibilities for activating the Operating Plan(s);

2.2. Processes to prepare for and mitigate Emergencies including:

2.2.1. Notification to its Reliability Coordinator to include current and projected conditions when experiencing a Capacity Emergency or Energy Emergency;

2.2.2. Requesting an Energy Emergency Alert, per Attachment 1;

2.2.3. Managing generating resources in its Balancing Authority Area to address:

2.2.3.1. Capability and availability;

2.2.3.2. Fuel supply and inventory concerns;

2.2.3.3. Fuel switching capabilities; and

2.2.3.4. Environmental constraints.

2.2.4. Public appeals for voluntary Load reductions;

2.2.5. Requests to government agencies to implement their programs to achieve necessary energy reductions;

2.2.6. Reduction of internal utility energy use;

2.2.7. Use of Interruptible Load, curtailable Load, and demand response;

2.2.8. Provisions for excluding critical natural gas infrastructure loads which are essential to the reliability of the BES, as defined by the Applicable Entity, as Interruptible Load, curtailable Load, and demand response during extreme cold weather periods within each Balancing Authority Area;

2.2.9. Provisions for Transmission Operators to implement operator-controlled manual Load shedding, undervoltage Load shedding, or underfrequency Load shedding in accordance with Requirement R1 Part 1.2.5; and

2.2.10. Provisions to determine reliability impacts of:

2.2.10.1. Cold weather conditions; and

2.2.10.2. Extreme weather conditions.

- M2.** Each Balancing Authority will have a dated Operating Plan(s) developed in accordance with Requirement R2 and reviewed by its Reliability Coordinator;

- evidence such as a review or revision history to indicate that the Operating Plan(s) has been maintained; and will have as evidence, such as operator logs or other operating documentation, voice recordings, or other communication documentation to show that its Operating Plan(s) was implemented for times when an Emergency has occurred, in accordance with Requirement R2.
- R3.** The Reliability Coordinator shall review the Operating Plan(s) to mitigate operating Emergencies submitted by a Transmission Operator or a Balancing Authority regarding any reliability risks that are identified between Operating Plans. *[Violation Risk Factor: High] [Time Horizon: Operations Planning]*
- 3.1.** Within 30 calendar days of receipt, the Reliability Coordinator shall:
- 3.1.1.** Review each submitted Operating Plan(s) on the basis of compatibility and inter-dependency with other Balancing Authorities' and Transmission Operators' Operating Plans;
 - 3.1.2.** Review each submitted Operating Plan(s) for coordination to avoid risk to Wide Area reliability; and
 - 3.1.3.** Notify each Balancing Authority and Transmission Operator of the results of its review, specifying any time frame for resubmittal of its Operating Plan(s) if revisions are identified.
- M3.** The Reliability Coordinator will have documentation, such as dated emails or other correspondences that it reviewed, Transmission Operator and Balancing Authority Operating Plans, within 30 calendar days of submittal in accordance with Requirement R3.
- R4.** Each Transmission Operator and Balancing Authority shall address any reliability risks identified by its Reliability Coordinator pursuant to Requirement R3 and resubmit its Operating Plan(s) to its Reliability Coordinator within a time period specified by its Reliability Coordinator. *[Violation Risk Factor: High] [Time Horizon: Operation Planning]*
- M4.** The Transmission Operator and Balancing Authority will have documentation, such as dated emails or other correspondence, with an Operating Plan(s) version history showing that it responded and updated the Operating Plan(s) within the timeframe identified by its Reliability Coordinator in accordance with Requirement R4.
- R5.** Each Reliability Coordinator that receives an Emergency notification from a Transmission Operator or Balancing Authority within its Reliability Coordinator Area shall notify, within 30 minutes from the time of receiving notification, other Balancing Authorities and Transmission Operators in its Reliability Coordinator Area, and neighboring Reliability Coordinators. *[Violation Risk Factor: High] [Time Horizon: Real-Time Operations]*
- M5.** Each Reliability Coordinator that receives an Emergency notification from a Balancing Authority or Transmission Operator within its Reliability Coordinator Area will have, and provide upon request, evidence that could include, but is not limited to, operator logs, voice recordings or transcripts of voice recordings, electronic communications, or equivalent evidence that will be used to determine if the Reliability Coordinator

- communicated, in accordance with Requirement R5, with other Balancing Authorities and Transmission Operators in its Reliability Coordinator Area, and neighboring Reliability Coordinators.
- R6.** Each Reliability Coordinator that has a Balancing Authority experiencing a potential or actual Energy Emergency within its Reliability Coordinator Area shall declare an Energy Emergency Alert, as detailed in Attachment 1. *[Violation Risk Factor: High] [Time Horizon: Real-Time Operations]*
- M6.** Each Reliability Coordinator, with a Balancing Authority experiencing a potential or actual Energy Emergency within its Reliability Coordinator Area, will have, and provide upon request, evidence that could include, but is not limited to, operator logs, voice recordings or transcripts of voice recordings, electronic communications, or equivalent evidence that it declared an Energy Emergency Alert, as detailed in Attachment 1, in accordance with Requirement R6.
- R7.** Each Transmission Operator shall annually identify and notify Distribution Providers, UFLS-Only Distribution Providers and Transmission Owners that are required to assist with the mitigation of operating Emergencies in its Transmission Operator Area through operator-controlled manual Load shedding, undervoltage Load shedding, or underfrequency Load shedding. *[Violation Risk Factor: Lower] [Time Horizon: Operations Planning, Long-term Planning]*
- M7.** Each Transmission Operator will have documentation, such as dated emails or other correspondences that it identified and notified Distribution Providers, UFLS-Only Distribution Providers and Transmission Owners annually in accordance with Requirement R7.
- R8.** Each Distribution Provider, UFLS-Only Distribution Provider, and Transmission Owner notified by a Transmission Operator per R7 to assist with the mitigation of operating Emergencies in its Transmission Operator Area shall develop, maintain, and implement a Load shedding plan. The Load shedding plan shall include the following, as applicable: *[Violation Risk Factor: High] [Time Horizon: Real-Time Operations, Operations Planning, Long-term Planning]*
- 8.1.** Operator-controlled manual Load shedding, undervoltage Load shedding, or underfrequency Load shedding during an Emergency that accounts for each of the following:
- 8.1.1.** Provisions for manual Load shedding capable of being implemented in a timeframe adequate for mitigating the Emergency;
 - 8.1.2.** Provisions to minimize the overlap of circuits that are designated for manual, undervoltage, or underfrequency Load shed and circuits that serve designated critical loads which are essential to the reliability of the BES;
 - 8.1.3.** Provisions to minimize the overlap of circuits that are designated for manual Load shed and circuits that are utilized for UFLS or UVLS;
 - 8.1.4.** Provisions for limiting the utilization of UFLS or UVLS circuits for manual

Load shed to situations where warranted by system conditions; and

8.1.5. Provisions for the identification and prioritization of designated critical natural gas infrastructure loads which are essential to the reliability of the BES as defined by the Applicable Entity.

8.2. Provisions to provide the Load shedding plan to the Transmission Operator for review.

M8. Each Distribution Provider, UFLS-Only Distribution Provider, and Transmission Owner notified by a Transmission Operator per R7 to assist with the mitigation of operating Emergencies in its Transmission Operator Area will have a dated Load shedding plan(s) developed in accordance with Requirement R8 and evidence that the Load shedding plan(s) was provided to its Transmission Operator; evidence such as a review or revision history to indicate that the Load shedding plan(s) has been maintained; and will have as evidence, such as operator logs or other operating documentation, voice recordings or other communication documentation to show that its Load shedding plan(s) was implemented for times when an Emergency has occurred, in accordance with Requirement R8.

C. Compliance

1. Compliance Monitoring Process

- 1.1. Compliance Enforcement Authority:** “Compliance Enforcement Authority” (CEA) means NERC or the Regional Entity, or any entity as otherwise designated by an Applicable Governmental Authority, in their respective roles of monitoring and/or enforcing compliance with the mandatory and enforceable Reliability Standards in their respective jurisdictions.
- 1.2. Evidence Retention:** The following evidence retention period(s) identify the period of time an entity is required to retain specific evidence to demonstrate compliance. For instances where the evidence retention period specified below is shorter than the time since the last audit, the CEA may ask an entity to provide other evidence to show that it was compliant for the full-time period since the last audit.

The applicable entity shall keep data or evidence to show compliance as identified below unless directed by its CEA to retain specific evidence for a longer period of time as part of an investigation.

- The Transmission Operator shall retain the current Operating Plan(s), evidence of review or revision history plus each version issued since the last audit and evidence of compliance since the last audit for Requirements R1 and R4.
 - The Balancing Authority shall retain the current Operating Plan(s), evidence of review or revision history plus each version issued since the last audit and evidence of compliance since the last audit for Requirements R2 and R4.
 - The Reliability Coordinator shall maintain evidence of compliance since the last audit for Requirements R3, R5, and R6.
 - The Transmission Operator shall maintain evidence of compliance since the last audit for Requirement R7.
 - The Distribution Provider, UFLS-Only Distribution Provider, and Transmission Owner shall retain the current Load shedding plan, evidence of review or revision history plus each version issued since the last audit and evidence of compliance since the last audit for Requirements R8.
- 1.3. Compliance Monitoring and Enforcement Program:** As defined in the NERC Rules of Procedure, “Compliance Monitoring and Enforcement Program” refers to the identification of the processes that will be used to evaluate data or information for the purpose of assessing performance or outcomes with the associated Reliability Standard.

Violation Severity Levels

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
R1	N/A	The Transmission Operator developed a Reliability Coordinator- reviewed Operating Plan(s) to mitigate operating Emergencies in its Transmission Operator Area, but failed to maintain it.	The Transmission Operator developed an Operating Plan(s) to mitigate operating Emergencies in its Transmission Operator Area, but failed to have it reviewed by its Reliability Coordinator.	The Transmission Operator failed to develop an Operating Plan(s) to mitigate operating Emergencies in its Transmission Operator Area. OR The Transmission Operator developed a Reliability Coordinator- reviewed Operating Plan(s) to mitigate operating Emergencies in its Transmission Operator Area, but failed to implement it.
R2	N/A	The Balancing Authority developed a Reliability Coordinator-reviewed Operating Plan(s) to mitigate operating Emergencies within its Balancing Authority Area, but failed to maintain it.	The Balancing Authority developed an Operating Plan(s) to mitigate operating Emergencies within its Balancing Authority Area, but failed to have it reviewed by its Reliability Coordinator.	The Balancing Authority failed to develop an Operating Plan(s) to mitigate operating Emergencies within its Balancing Authority Area. OR The Balancing Authority developed a Reliability Coordinator-reviewed Operating Plan(s) to mitigate operating Emergencies within its Balancing Authority Area, but failed to implement it.

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
R3	N/A	N/A	The Reliability Coordinator identified a reliability risk, but failed to notify the Balancing Authority or Transmission Operator within 30 calendar days.	The Reliability Coordinator identified a reliability risk, but failed to notify the Balancing Authority or Transmission Operator.
R4	N/A	N/A	The Transmission Operator or Balancing Authority failed to update and resubmit its Operating Plan(s) to its Reliability Coordinator within the timeframe specified by its Reliability Coordinator.	The Transmission Operator or Balancing Authority failed to update and resubmit its Operating Plan(s) to its Reliability Coordinator.
R5	N/A	N/A	The Reliability Coordinator that received an Emergency notification from a Transmission Operator or Balancing Authority did notify neighboring Reliability Coordinators, Balancing Authorities and Transmission Operators, but failed to notify within 30 minutes from the time of receiving notification.	The Reliability Coordinator that received an Emergency notification from a Transmission Operator or Balancing Authority failed to notify neighboring Reliability Coordinators, Balancing Authorities and Transmission Operators.
R6	N/A	N/A	N/A	The Reliability Coordinator that had a Balancing Authority experiencing a potential or actual Energy Emergency within its Reliability Coordinator Area failed to declare an Energy Emergency

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
				Alert.
R7	N/A	The Transmission Operator identified on an annual basis the Distribution Providers, UFLS-Only Distribution Providers and Transmission Owners that are required to assist with the mitigation of operating Emergencies in its Transmission Operator Area through Operator-controlled manual Load shedding, undervoltage Load shedding, or underfrequency Load shedding, but notified one or more of those entities more than one, but fewer than 30 days late.	The Transmission Operator identified on an annual basis the Distribution Providers, UFLS-Only Distribution Providers and Transmission Owners, that are required to assist with the mitigation of operating Emergencies in its Transmission Operator Area through Operator-controlled manual Load shedding, undervoltage Load shedding, or underfrequency Load shedding, but notified one or more of those entities 30 days or more, but fewer than 60 days late.	The Transmission Operator did not identify or notify Distribution Providers, UFLS-Only Distribution Providers and Transmission Owners, that are required to assist with the mitigation of operating Emergencies in its Transmission Operator Area through Operator-controlled manual Load shedding, undervoltage Load shedding, or underfrequency Load shedding. OR The Transmission Operator identified on an annual basis the Distribution Providers, UFLS-Only Distribution Providers and Transmission Owners, that are required to assist with the mitigation of operating Emergencies in its Transmission Operator Area through Operator-controlled manual Load shedding, undervoltage Load shedding, or underfrequency Load shedding, but notified one

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
				OR more of those entities 60 days or more late.
R8	N/A	The applicable Distribution Provider, UFLS-Only Distribution Provider, and Transmission Owner developed a Load shedding plan(s), but failed to maintain it in accordance with Requirement R8.	The applicable Distribution Provider, UFLS-Only Distribution Provider, and Transmission Owner developed a Load shedding plan(s), but failed to provide it to its Transmission Operator in accordance with Requirement R8.	The applicable Distribution Provider, UFLS-Only Distribution Provider, and Transmission Owner failed to develop a Load shedding plan(s) in accordance with Requirement R8. OR The Distribution Provider, UFLS-Only Distribution Provider, and Transmission Owner developed a Load shedding plan(s), but failed to implement it in accordance with Requirement R8.

D. Regional Variances

None.

E. Interpretations

None.

F. Associated Documents

None.

Version History

Version	Date	Action	Change Tracking
1	November 13, 2014	Adopted by the NERC Board of Trustees	Merged EOP-001-2.1b, EOP-002-3.1 and EOP-003-2.
1	November 19, 2015	FERC approved EOP-011-1. Docket Nos. RM15-7-000, RM15-12-000, and RM15-13-000. Order No. 818	
2	June 11, 2021	Adopted by the NERC Board of Trustees	Revised under Project 2019-06
2	August 24, 2021	FERC approved EOP-011-2. Docket Number RD21-5-000	
3	October 26, 2022	Adopted by the NERC Board of Trustees	Revised under Project 2021-07
3	February 16, 2023	FERC approved EOP-011-3. <i>N. Am. Elec. Reliability Corp.</i> , 182 FERC 61,094	
4	October 23, 2023	Adopted by the NERC Board of Trustees	Revised under Project 2021-07
4	February 15, 2024	FERC Order issued approving EOP-011-4. Docket No. RD24-1-000	

Attachment 1-EOP-011-4 Energy Emergency Alerts

Introduction

This Attachment provides the process and descriptions of the levels used by the Reliability Coordinator in which it communicates the condition of a Balancing Authority which is experiencing an Energy Emergency.

A. General Responsibilities

- 1. Initiation by Reliability Coordinator.** An Energy Emergency Alert (EEA) may be initiated only by a Reliability Coordinator at 1) the Reliability Coordinator's own request, or 2) upon the request of an energy deficient Balancing Authority.
- 2. Notification.** A Reliability Coordinator who declares an EEA shall notify all Balancing Authorities and Transmission Operators in its Reliability Coordinator Area. The Reliability Coordinator shall also notify all neighboring Reliability Coordinators.

B. EEA Levels

Introduction

To ensure that all Reliability Coordinators clearly understand potential and actual Energy Emergencies in the Interconnection, NERC has established three levels of EEAs. The Reliability Coordinators will use these terms when communicating Energy Emergencies to each other. An EEA is an Emergency procedure, not a daily operating practice, and is not intended as an alternative to compliance with NERC Reliability Standards.

The Reliability Coordinator may declare whatever alert level is necessary, and need not proceed through the alerts sequentially.

- 1. EEA 1 — All available generation resources in use. Circumstances:**
 - The Balancing Authority is experiencing conditions where all available generation resources are committed to meet firm Load, firm transactions, and reserve commitments, and is concerned about sustaining its required Contingency Reserves.
 - Non-firm wholesale energy sales (other than those that are recallable to meet reserve requirements) have been curtailed.
- 2. EEA 2 — Load management procedures in effect. Circumstances:**
 - The Balancing Authority is no longer able to provide its expected energy requirements and is an energy deficient Balancing Authority.
 - An energy deficient Balancing Authority has implemented its Operating Plan(s) to mitigate Emergencies.

- An energy deficient Balancing Authority is still able to maintain minimum Contingency Reserve requirements.

During EEA 2, Reliability Coordinators and energy deficient Balancing Authorities have the following responsibilities:

- 2.1 Notifying other Balancing Authorities and market participants.** The energy deficient Balancing Authority shall communicate its needs to other Balancing Authorities and market participants. Upon request from the energy deficient Balancing Authority, the respective Reliability Coordinator shall post the declaration of the alert level, along with the name of the energy deficient Balancing Authority on the RCIS website.
 - 2.2 Declaration period.** The energy deficient Balancing Authority shall update its Reliability Coordinator of the situation at a minimum of every hour until the EEA 2 is terminated. The Reliability Coordinator shall update the energy deficiency information posted on the RCIS website as changes occur and pass this information on to the neighboring Reliability Coordinators, Balancing Authorities and Transmission Operators.
 - 2.3 Sharing information on resource availability.** Other Reliability Coordinators of Balancing Authorities with available resources shall coordinate, as appropriate, with the Reliability Coordinator that has an energy deficient Balancing Authority.
 - 2.4 Evaluating and mitigating Transmission limitations.** The Reliability Coordinator shall review Transmission outages and work with the Transmission Operator(s) to see if it's possible to return to service any Transmission Elements that may relieve the loading on System Operating Limits (SOLs) or Interconnection Reliability Operating Limits (IROLs).
 - 2.5 Requesting Balancing Authority actions.** Before requesting an EEA 3, the energy deficient Balancing Authority must make use of all available resources; this includes, but is not limited to:
 - 2.5.1 All available generation units are on line.** All generation capable of being on line in the time frame of the Emergency is on line.
 - 2.5.2 Demand-Side Management.** Activate Demand-Side Management within provisions of any applicable agreements.
- 3. EEA 3 — Firm Load interruption is imminent or in progress. Circumstances:**
- The energy deficient Balancing Authority is unable to meet minimum Contingency Reserve requirements.

During EEA 3, Reliability Coordinators and Balancing Authorities have the following responsibilities:

- 3.1 Continue actions from EEA 2.** The Reliability Coordinators and the energy deficient Balancing Authority shall continue to take all actions initiated during EEA 2.

- 3.2 Declaration Period.** The energy deficient Balancing Authority shall update its Reliability Coordinator of the situation at a minimum of every hour until the EEA 3 is terminated. The Reliability Coordinator shall update the energy deficiency information posted on the RCIS website as changes occur and pass this information on to the neighboring Reliability Coordinators, Balancing Authorities, and Transmission Operators.
- 3.3 Reevaluating and revising SOLs and IROLs.** The Reliability Coordinator shall evaluate the risks of revising SOLs and IROLs for the possibility of delivery of energy to the energy deficient Balancing Authority. Reevaluation of SOLs and IROLs shall be coordinated with other Reliability Coordinators and only with the agreement of the Transmission Operator whose Transmission Owner (TO) equipment would be affected. SOLs and IROLs shall only be revised as long as an EEA 3 condition exists, or as allowed by the Transmission Owner whose equipment is at risk. The following are minimum requirements that must be met before SOLs or IROLs are revised:
- 3.3.1 Energy deficient Balancing Authority obligations.** The energy deficient Balancing Authority, upon notification from its Reliability Coordinator of the situation, will immediately take whatever actions are necessary to mitigate any undue risk to the Interconnection. These actions may include Load shedding.
- 3.4 Returning to pre-Emergency conditions.** Whenever energy is made available to an energy deficient Balancing Authority such that the Systems can be returned to its pre- Emergency SOLs or IROLs condition, the energy deficient Balancing Authority shall request the Reliability Coordinator to downgrade the alert level.
- 3.4.1 Notification of other parties.** Upon notification from the energy deficient Balancing Authority that an alert has been downgraded, the Reliability Coordinator shall notify the neighboring Reliability Coordinators (via the RCIS), Balancing Authorities, and Transmission Operators that its Systems can be returned to its normal limits.
- Alert 0 - Termination.** When the energy deficient Balancing Authority is able to meet its Load and Operating Reserve requirements, it shall request its Reliability Coordinator to terminate the EEA.
- 3.4.2 Notification.** The Reliability Coordinator shall notify all other Reliability Coordinators via the RCIS of the termination. The Reliability Coordinator shall also notify the neighboring Balancing Authorities and Transmission Operators.

BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c))
Emergency Order: Transalta)
Centralia Generation LLC)
_____)

Order No. 202-25-11

Motion to Intervene, Motion for Clarification, and Requests for Rehearing and Stay
of Sierra Club, NW Energy Coalition, Washington Conservation Action, Climate
Solutions, Public Citizen, and Environmental Defense Fund
(collectively, “Public Interest Organizations” or “PIOs”)

Exhibit 1-99:
2001 National Energy Policy

National Energy Policy



Report of the
National Energy Policy Development Group

May 2001

Reliable, Affordable, and Environmentally Sound Energy for America's Future

**Report of the
National Energy Policy Development Group**

*“America must have an energy policy that plans
for the future, but meets the needs of today.
I believe we can develop our natural resources
and protect our environment.”*

— President George W. Bush



THE VICE PRESIDENT
WASHINGTON

May 16, 2001

The Honorable George W. Bush
President of the United States
The White House
Washington, D.C. 20500

Dear Mr. President:

On behalf of the National Energy Policy Development Group, I submit for your consideration our National Energy Policy report. As you directed us at the outset of your Administration, we have developed a national energy policy designed to help bring together business, government, local communities and citizens to promote dependable, affordable and environmentally sound energy for the future.

The report reflects the requirements and philosophy you set out for our work. It envisions a comprehensive long-term strategy that uses leading edge technology to produce an integrated energy, environmental and economic policy. To achieve a 21st century quality of life -- enhanced by reliable energy and a clean environment -- we must modernize conservation, modernize our infrastructure, increase our energy supplies, including renewables, accelerate the protection and improvement of our environment, and increase our energy security.

We submit these recommendations with optimism. The tasks ahead are great but achievable. To meet our energy challenge, we must put to good use the resources around us and the talents within us. It summons the best of America and offers a healthier environment, a stronger economy and a brighter future for the American people.

Sincerely,

A handwritten signature in blue ink that reads "Dick Cheney". The signature is fluid and cursive, with the first name "Dick" and the last name "Cheney" clearly distinguishable.

Enclosure

Members of the National Energy Policy Development Group

DICK CHENEY

The Vice President

COLIN L. POWELL

The Secretary of State

PAUL O'NEILL

The Secretary of the Treasury

GALE NORTON

The Secretary of the Interior

ANN M. VENEMAN

The Secretary of Agriculture

DONALD L. EVANS

The Secretary of Commerce

NORMAN Y. MINETA

The Secretary of Transportation

SPENCER ABRAHAM

The Secretary of Energy

JOE M. ALLBAUGH

The Director of the Federal Emergency Management Agency

CHRISTINE TODD WHITMAN

The Administrator of the Environmental Protection Agency

JOSHUA B. BOLTEN

The Assistant to the President and Deputy Chief of Staff for Policy

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The Director of the Office of Management and Budget

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The Assistant to the President for Economic Policy

RUBEN BARRALES

Deputy Assistant to the President and Director of Intergovernmental Affairs

Executive Director: Andrew D. Lundquist

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Overview

Reliable, Affordable, and Environmentally Sound Energy for America's Future

In his second week in office, President George W. Bush established the National Energy Policy Development Group, directing it to “develop a national energy policy designed to help the private sector, and, as necessary and appropriate, State and local governments, promote dependable, affordable, and environmentally sound production and distribution of energy for the future.” This Overview sets forth the National Energy Policy Development (NEPD) Group’s findings and key recommendations for a National Energy Policy.

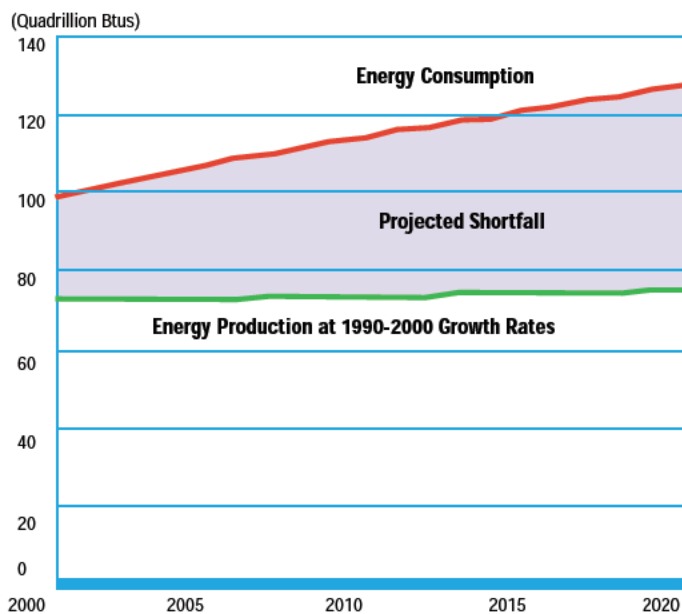
America in the year 2001 faces the most serious energy shortage since the oil embargoes of the 1970s. The effects are already being felt nationwide. Many families face energy bills two to three times higher than they were a year ago. Millions of Americans find themselves dealing with rolling blackouts or brownouts; some employers must lay off workers or curtail production to absorb the rising cost of energy. Drivers across America are paying higher and higher gasoline prices.

Californians have felt these problems most acutely. California actually began the 1990s with a surplus of electricity generating capacity. Yet despite an economic boom, a rapidly growing population, and a corresponding increase in energy needs, California did not add a single new major electric power plant during the 1990s. The result is a demand for electricity that greatly exceeds the amount available.

A fundamental imbalance between supply and demand defines our nation’s energy crisis. As the chart illustrates, if energy production increases at the same rate as during the last decade our projected energy needs will far outstrip expected levels of production.

This imbalance, if allowed to continue, will inevitably undermine our economy, our standard of living, and our national security. But it is not beyond our power to correct. America leads the world in scientific achievement, technical skill, and entrepreneurial drive. Within our country are abundant natural resources, unrivaled technology, and unlimited human creativity. With forward-looking leadership and sensible policies, we can meet our fu-

Figure 1
Growth in U.S. Energy Consumption Is Outpacing Production



Over the next 20 years, growth in U.S. energy consumption will increasingly outpace U.S. energy production, if production only grows at the rate of the last 10 years.

Sources: Sandia National Laboratories and U.S. Department of Energy, Energy Information Administration.



America's expanding economy, growing population, and rising standard of living will be sustained by our unmatched technological know-how.

ture energy demands and promote energy conservation, and do so in environmentally responsible ways that set a standard for the world.

The Challenge

America's energy challenge begins with our expanding economy, growing population, and rising standard of living. Our prosperity and way of life are sustained by energy use. America has the technological know-how and environmentally sound 21st century technologies needed to meet the principal energy challenges we face: promoting energy conservation, repairing and modernizing our energy infrastructure, and increasing our energy supplies in ways that protect and improve the environment. Meeting each of these challenges is critical to expanding our economy, meeting the needs of a growing population, and raising the American standard of living.

We are already working to meet the first challenge: using energy more wisely. Dramatic technological advances in energy efficiency have enabled us to make great strides in conservation, from the operation of farms and factories to the construction of

buildings and automobiles. New technology allows us to go about our lives and work with less cost, less effort, and less burden on the natural environment. While such advances cannot alone solve America's energy problems, they can and will continue to play an important role in our energy future.

The second challenge is to repair and expand our energy infrastructure. Our current, outdated network of electric generators, transmission lines, pipelines, and refineries that convert raw materials into usable fuel has been allowed to deteriorate. Oil pipelines and refining capacity are in need of repair and expansion. Not a single major oil refinery has been built in the United States in nearly a generation, causing the kind of bottlenecks that lead to sudden spikes in the price of gasoline. Natural gas distribution, likewise, is hindered by an aging and inadequate network of pipelines. To match supply and demand will require some 38,000 miles of new gas pipelines, along with 255,000 miles of distribution lines. Similarly, an antiquated and inadequate transmission grid prevents us from routing electricity over long distances and thereby avoiding regional blackouts, such as California's.

“America must have an energy policy that plans for the future, but meets the needs of today. I believe we can develop our natural resources and protect our environment.”

— President
George W. Bush

Increasing energy supplies while protecting the environment is the third challenge. Even with successful conservation efforts, America will need more energy.

Renewable and alternative fuels offer hope for America's energy future. But they supply only a small fraction of present energy needs. The day they fulfill the bulk of our needs is still years away. Until that day comes, we must continue meeting the nation's energy requirements by the means available to us.

Estimates indicate that over the next 20 years, U.S. oil consumption will increase by 33 percent, natural gas consumption by well over 50 percent, and demand for electricity will rise by 45 percent. If America's energy production grows at the same rate as it did in the 1990s we will face an ever-increasing gap.

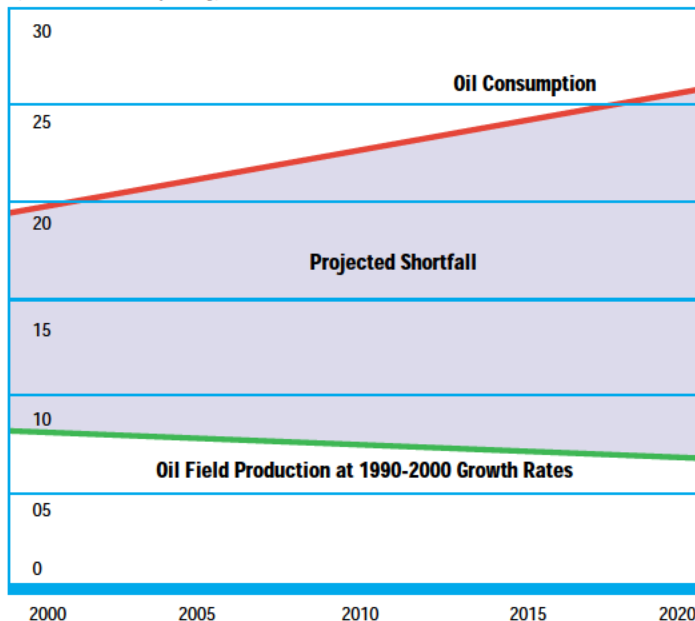
Increases on this scale will require preparation and action today. Yet America has not been bringing on line the necessary supplies and infrastructure.

Extraordinary advances in technology have transformed energy exploration and production. Yet we produce 39 percent less oil today than we did in 1970, leaving us ever more reliant on foreign suppliers. On our present course, America 20 years from now will import nearly two of every three barrels of oil – a condition of increased dependency on foreign powers that do not always have America's interests at heart. Our increasing demand for natural gas – one of the cleanest forms of energy – far exceeds the current rate of production. We should reconsider any regulatory restrictions that do not take technological advances into account.

Figure 2

U.S. Oil Consumption Will Continue to Exceed Production

(Millions of Barrels per Day)



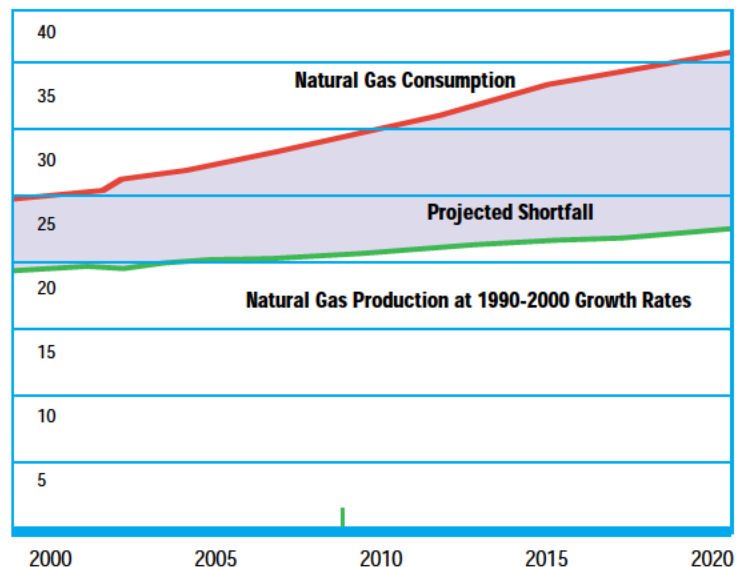
Over the next 20 years, U.S. oil consumption will grow by over 6 million barrels per day. If U.S. oil production follows the same historical pattern of the last 10 years, it will decline by 1.5 million barrels per day. To meet U.S. oil demand, oil and product imports would have to grow by a combined 7.5 million barrels per day. In 2020, U.S. oil production would supply less than 30 percent of U.S. oil needs.

Sources: Sandia National Laboratories and U.S. Department of Energy, Energy Information Administration.

Figure 3

U.S. Natural Gas Consumption Is Outpacing Production

(Trillion Cubic Feet)



Over the next 20 years, U.S. natural gas consumption will grow by over 50 percent. At the same time, U.S. natural gas production will grow by only 14 percent, if it grows at the rate of the last 10 years.

Sources: Sandia National Laboratories and U.S. Department of Energy, Energy Information Administration.

erview chart

We have a similar opportunity to increase our supplies of electricity. To meet projected demand over the next two decades, America must have in place between 1,300 and 1,900 new electric plants. Much of this new generation will be fueled by natural gas. However, existing and new technologies offer us the opportunity to expand nuclear generation as well. Nuclear power today accounts for 20 percent of our country's electricity. This power source, which causes no greenhouse gas emissions, can play an expanding part in our energy future.

The recommendations of this report address the energy challenges facing America. Taken together, they offer the thorough and responsible energy plan our nation has long needed.

Components of the National Energy Policy

The National Energy Policy we propose follows three basic principles:

- The Policy is a long-term, comprehensive strategy. Our energy crisis has been years in the making, and will take years to put fully behind us.
- The Policy will advance new, environmentally friendly technologies to increase energy supplies and encourage cleaner, more efficient energy use.
- The Policy seeks to raise the living standards of the American people, recognizing that to do so our country must fully integrate its energy, environmental, and economic policies.

Applying these principles, we urge action to meet five specific national goals. America must modernize conservation, modernize our energy infrastructure, increase energy supplies, accelerate the protection and improvement of the environment, and increase our nation's energy security.

Modernize Conservation

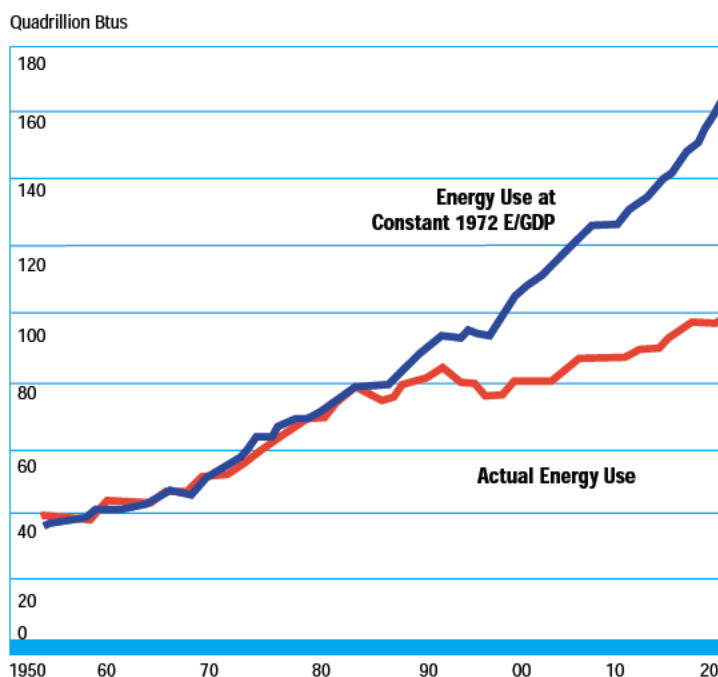
Americans share the goal of energy conservation. The best way of meeting this goal is to increase energy efficiency by applying new technology – raising productivity, reducing waste, and trimming costs. In addition, it holds out great hope for improving the quality of the environment. American families, communities, and businesses all depend upon reliable and affordable energy services for their well being and safety. From transportation to communication, from air conditioning to lighting, energy is critical to nearly everything we do in life and work. Public policy can and should encourage energy conservation.

Over the past three decades, America has made impressive gains in energy efficiency. Today's automobiles, for example, use about 60 percent of the gasoline they

“Here we aim to continue a path of uninterrupted progress in many fields... New technologies are proving that we can save energy without sacrificing our standard of living. And we're going to encourage it in every way possible.”

— Vice President
Richard B. Cheney

Figure 4
U.S. Economy is More Energy Efficient (Energy Intensity)
Primary Energy Use



Improvements in energy efficiency since the 1970s have had a major impact in meeting national energy needs relative to new supply. If the intensity of U.S. energy use had remained constant since 1972, consumption would have been about 70 quadrillion Btus (74 percent) higher in 1999 than it actually was.

Source: U.S. Department of Energy, Energy Information Administration.

“For the electricity we need, we must be ambitious. Transmission grids stand in need of repair, upgrading, and expansion. . . . If we put these connections in place, we’ll go a long way toward avoiding future blackouts.”

— Vice President
Richard B. Cheney

did in 1972, while new refrigerators require just one-third the electricity they did 30 years ago. As a result, since 1973, the U.S. economy has grown by 126 percent, while energy use has increased by only 30 percent. In the 1990s alone, manufacturing output expanded by 41 percent, while industrial electricity consumption grew by only 11 percent. We must build on this progress and strengthen America’s commitment to energy efficiency and conservation.

The National Energy Policy builds on our nation’s successful track record and will promote further improvements in the productive and efficient use of energy. This report includes recommendations to:

- Direct federal agencies to take appropriate actions to responsibly conserve energy use at their facilities, especially during periods of peak demand in regions where electricity shortages are possible, and to report to the President on actions taken.
- Increase funding for renewable energy and energy efficiency research and development programs that are performance-based and cost-shared.
- Create an income tax credit for the purchase of hybrid and fuel cell vehicles to promote fuel-efficient vehicles.
- Extend the Department of Energy’s “Energy Star” efficiency program to include schools, retail buildings, health care facilities, and homes and extend the “Energy Star” labeling program to additional products and appliances.
- Fund the federal government’s Intelligent Transportation Systems program, the fuel cell powered transit bus program, and the Clean Buses program.
- Provide a tax incentive and streamline permitting to accelerate the development of clean Combined Heat and Power technology.
- Direct the Secretary of Transportation to review and provide recommendations on establishing Corporate Average Fuel Economy (CAFE) standards

with due consideration to the National Academy of Sciences study of CAFE standards to be released in July, 2001.

Modernize Our Energy Infrastructure

The energy we use passes through a vast nationwide network of generating facilities, transmission lines, pipelines, and refineries that converts raw resources into usable fuel and power. That system is deteriorating, and is now strained to capacity.

One reason for this is government regulation, often excessive and redundant. Regulation is needed in such a complex field, but it has become overly burdensome. Regulatory hurdles, delays in issuing permits, and economic uncertainty are limiting investment in new facilities, making our energy markets more vulnerable to transmission bottlenecks, price spikes and supply disruptions. America needs more environmentally-sound energy projects to connect supply sources to growing markets and to deliver energy to homes and business.

To reduce the incidence of electricity blackouts, we must greatly enhance our ability to transmit electric power between geographic regions, that is, sending power to where it is needed from where it is produced. Most of America’s transmission lines, substations, and transformers were built when utilities were tightly regulated and provided service only within their assigned regions. The system is simply unequipped for large-scale swapping of power in the highly competitive market of the 21st century.

The National Energy Policy will modernize and expand our energy infrastructure in order to ensure that energy supplies can be safely, reliably, and affordably transported to homes and businesses. This report includes recommendations to:

- Direct agencies to improve pipeline safety and expedite pipeline permitting.
- Issue an Executive Order directing federal agencies to expedite permits and coordinate federal, state, and local actions necessary for energy-related project approvals on a national basis

in an environmentally sound manner, and establish an interagency task force chaired by the Council on Environmental Quality. The task force will ensure that federal agencies set up appropriate mechanisms to coordinate federal, state and local permitting activity in particular regions where increased activity is expected.

- Grant authority to obtain rights-of-way for electricity transmission lines with the goal of creating a reliable national transmission grid. Similar authority already exists for natural gas pipelines and highways.
- Enact comprehensive electricity legislation that promotes competition, encourages new generation, protects consumers, enhances reliability, and promotes renewable energy.
- Implement administrative and regulatory changes to improve the reliability of the interstate transmission system and enact legislation to provide for enforcement of electricity reliability standards.
- Expand the Energy Department's research and development on transmission reliability and superconductivity.

Increase Energy Supplies

A primary goal of the National Energy Policy is to add supply from diverse sources. This means domestic oil, gas, and coal. It also means hydropower and nuclear power. And it means making greater use of non-hydro renewable sources now available.

One aspect of the present crisis is an increased dependence, not only on foreign oil, but on a narrow range of energy options. For example, about 90 percent of all new electricity plants currently under construction will be fueled by natural gas. While natural gas has many advantages, an over-reliance on any one fuel source leaves consumers vulnerable to price spikes and supply disruptions. There are several other fuel sources available that can help meet our needs.

Currently, the U.S. has enough coal to last for another 250 years. Yet very few

coal-powered electric plants are now under construction. Research into clean coal technologies may increase the attractiveness of coal as a source for new generation plants.

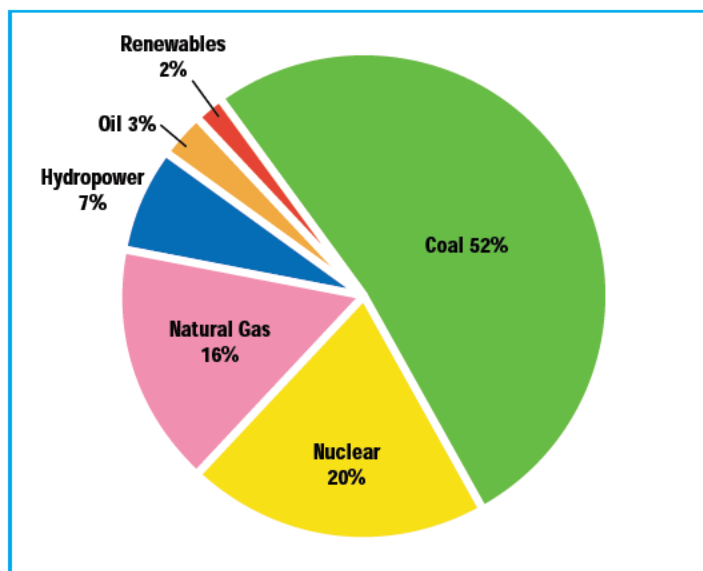
Nuclear power plants serve millions of American homes and businesses, have a dependable record for safety and efficiency, and discharge no greenhouse gases into the atmosphere. As noted earlier, these facilities currently generate 20 percent of all electricity in America, and more than 40 percent of electricity generated in 10 states in the Northeast, South, and Midwest. Other nations, such as Japan and France, generate a much higher percentage of their electricity from nuclear power. Yet the number of nuclear plants in America is actually projected to decline in coming years, as old plants close and none are built to replace them.

Enormous advances in technology have made oil and natural gas exploration and production both more efficient and more environmentally sound. Better technology means fewer rigs, more accurate drilling, greater resource recovery and envi-

“As a country, we have demanded more and more energy. But we have not brought on line the supplies needed to meet that demand.... We can explore for energy, we can produce energy and use it, and we can do so with a decent regard for the natural environment.”

—Vice President
Richard B. Cheney

Figure 5
Fuel Sources for Electricity Generation in 2000



Electricity is a secondary source of energy, generated through the consumption of primary sources. Coal and nuclear energy account for nearly 75 percent of U.S. electricity generation.

Source: U.S. Department of Energy, Energy Information Administration

“We will insist on protecting and enhancing the environment, showing consideration for the air and natural lands and watersheds of our country.”

— Vice President
Richard B. Cheney

ronmentally friendly exploration. Drilling pads are 80 percent smaller than a generation ago. High-tech drilling allows us to access supplies five to six miles away from a single compact drilling site, leaving sensitive wetlands and wildlife habitats undisturbed. Yet the current regulatory structure fails to take sufficient account of these extraordinary advances, excessively restricting the environmentally safe production of energy from many known sources.

Our policy will increase and diversify our nation’s sources of traditional and alternative fuels in order to furnish families and businesses with reliable and affordable energy, to enhance national security, and to improve the environment. This report includes recommendations to:

- Issue an Executive Order directing all federal agencies to include in any regulatory action that could significantly and adversely affect energy supplies a detailed statement on the energy impact of the proposed action.
- Open a small fraction of the Arctic National Wildlife Refuge to environmentally regulated exploration and production using leading-edge technology. Examine the potential for the regulated increase in oil and natural gas development on other federal lands.
- Earmark \$1.2 billion of bid bonuses from the environmentally responsible leasing of ANWR to fund research into alternative and renewable energy resources – including wind, solar, biomass, and geothermal.
- Enact legislation to expand existing alternative fuels tax incentives to include landfills that capture methane gas emissions for electricity generation and to electricity produced from wind and biomass. Extend the number of eligible biomass sources to include forest-related sources, agricultural sources, and certain urban sources.
- Provide \$2 billion over 10 years to fund clean coal technology research and a new credit for electricity produced from biomass co-fired with coal.
- Direct federal agencies to streamline the

hydropower relicensing process with proper regard given to environmental factors.

- Provide for the safe expansion of nuclear energy by establishing a national repository for nuclear waste, and by streamlining the licensing of nuclear power plants.

Accelerate Protection and Improvement of the Environment

America’s commitment to environmental protection runs deep. We are all aware of past excesses in our use of the natural world and its resources. No one wishes to see them repeated. In the 21st century, the ethic of good stewardship is well established in American life and law.

We do not accept the false choice between environmental protection and energy production. An integrated approach to policy can yield a cleaner environment, a stronger economy, and a sufficient supply of energy for our future. The primary reason for that has been steady advances in the technology of locating, producing, and using energy. Since 1970, emissions of key air emissions are down 31 percent. Cars today emit 85 percent less carbon monoxide than 30 years ago. Lead emissions are down 90 percent. Lead levels in ambient air today are 98 percent lower than they were in 1970. America is using more, and polluting less.

One of the factors harming the environment today is the very lack of a comprehensive, long-term national energy policy. States confronting blackouts must take desperate measures, often at the expense of environmental standards, requesting waivers of environmental rules, and delaying the implementation of anti-pollution efforts. Shortfalls in electricity generating capacity and short-sighted policies have blocked construction of new, cleaner plants, leaving no choice but to rely on older, inefficient plants to meet demand. The increased use of emergency power sources, such as diesel generators, results in greater air pollution.

New anti-pollution technologies hold great promise for the environment. The same can be said of 21st century power generators that must soon replace older models; signifi-

cant new resources for land conservation efforts; and continued research into renewable energy sources. All have a place in the National Energy Policy.

The National Energy Policy will build upon our nation's successful track record and will promote further improvements in the productive and efficient use of energy. This report includes recommendations to:

- Enact “multi-pollutant” legislation to establish a flexible, market-based program to significantly reduce and cap emissions of sulfur dioxide, nitrogen oxides, and mercury from electric power generators.
- Increase exports of environmentally friendly, market-ready U.S. technologies that generate a clean environment and increase energy efficiency.
- Establish a new “Royalties Conservation Fund” and earmark royalties from new, clean oil and gas exploration in ANWR to fund land conservation efforts.
- Implement new guidelines to reduce truck idling emissions at truck stops.

Increase Energy Security.

The National Energy Policy seeks to lessen the impact on Americans of energy price volatility and supply uncertainty. Such uncertainty increases as we reduce America's dependence on foreign sources of energy. At the same time, however, we recognize that a significant percentage of our resources will come from overseas. Energy security must be a priority of U.S. trade and foreign policy.

We must look beyond our borders and restore America's credibility with overseas suppliers. In addition, we must build strong relationships with energy-producing nations in our own hemisphere, improving the outlook for trade, investment, and reliable supplies.

Energy security also requires preparing our nation for supply emergencies, and assisting low-income Americans who are most vulnerable in times of supply disruption, price spikes, and extreme weather.

To ensure energy security for our nation and its families, our report includes these recommendations:

- Dedicate new funds to the Low Income Home Energy Assistance Program by funneling a portion of oil and gas royalty payments to LIHEAP when oil and natural gas prices exceed a certain amount.
- Double funding for the Department of Energy's Weatherization Assistance Program, increasing funding by \$1.4 billion over 10 years.
- Direct the Federal Emergency Management Administration to prepare for potential energy-related emergencies.
- Support a North American Energy Framework to expand and accelerate cross-border energy investment, oil and gas pipelines, and electricity grid connections by streamlining and expediting permitting procedures with Mexico and Canada. Direct federal agencies to expedite necessary permits for a gas pipeline route from Alaska to the lower 48 states.

Looking Toward the Future

The President's goal of reliable, affordable, and environmentally sound energy supplies will not be reached overnight. It will call forth innovations in science, research, and engineering. It will require time and the best efforts of leaders in both political parties. It will require also that we deal with the facts as they are, meeting serious problems in a serious way. The complacency of the past decade must now give way to swift but well-considered action.

Present trends are not encouraging, but they are not immutable. They are among today's most urgent challenges, and well within our power to overcome. Our country has met many great tests. Some have imposed extreme hardship and sacrifice. Others have demanded only resolve, ingenuity, and clarity of purpose. Such is the case with energy today.

We submit these recommendations with optimism. We believe that the tasks ahead, while great, are achievable. The energy crisis is a call to put to good use the resources around us, and the talents within us. It summons the best of America, and offers the best of rewards – in new jobs, a healthier environment, a stronger economy, and a brighter future for our people.

“The goals of this strategy are clear: to ensure a steady supply of affordable energy for America's homes and businesses and industries.”

— President
George W. Bush

Taking Stock

Energy Challenges Facing the United States

America's current energy challenges can be met with rapidly improving technology, dedicated leadership, and a comprehensive approach to our energy needs.

Our challenge is clear—we must use technology to reduce demand for energy, repair and maintain our energy infrastructure, and increase energy supply. Today, the United States remains the world's undisputed technological leader; but recent events have demonstrated that we have yet to integrate 21st-century technology into an energy plan that is focused on wise energy use, production, efficiency, and conservation.

Prices today for gasoline, heating oil, and natural gas are dramatically higher than they were only a year ago. In California, homeowners, farmers, and businesses face soaring electricity prices, rolling blackouts, increasing financial turmoil, and an uncertain energy future. Our nation's dependence on foreign sources of oil is at an all-time high and is expected to grow. Current high energy prices and supply shortages are hurting U.S. consumers and businesses, as well as their prospects for continued economic growth.

Our national energy policy must be comprehensive in scope. It must protect our environment. It must also increase our supply of domestic oil, natural gas, coal, nuclear, and renewable energy sources. Our failure over the past several years to modernize our energy infrastructure—the network of transmission lines, gas pipelines, and oil refineries that transports our energy to consumers and converts raw materials into usable fuels—is a result of the

lack of careful planning and lack of a comprehensive national energy plan. The United States faces serious energy challenges: electricity shortages and disruptions in California and elsewhere in the West, dramatic increases in gasoline prices due to record-low inventories, a strained supply system, and continued dependence on foreign suppliers. These challenges have developed from years of neglect and can only be addressed with the implementation of sound policy. There are no easy, short-term solutions.

Our increased dependence on foreign oil profoundly illustrates our nation's failure to establish an effective energy policy. Between 1991 and 2000, Americans used 17 percent more energy than in the previous decade, while during that same period, domestic energy production rose by only 2.3 percent. While U.S. production of coal, natural gas, nuclear energy, and renewable energy has increased somewhat in recent years, these increases have been largely offset by declines in domestic oil production. As a result, America has met almost all of its increased energy demand over the past ten years with increased imports.

U.S. energy consumption is projected to increase by about 32 percent by 2020. Unless a comprehensive national energy policy is adopted, Americans will continue to feel the effects of an inadequate electrical transmission grid, a pipeline system stretched to capacity, insufficient domestic energy supply, and a regional imbalance in supply sources. It is important that we meet these challenges with a comprehensive energy plan that takes a long-term approach to meeting our energy needs.



The U.S. economy depends on reliable and affordable energy. In the coming months, we face several serious long-term energy challenges: electricity shortages and disruptions in California and the West, dramatic increases in gasoline prices due to record-low inventories, a strained supply system, and continued dependence on foreign suppliers.



California's Energy Challenge

Recent and looming electricity blackouts in California demonstrate the problem of neglecting energy supply. They also foretell the consequences of failing to implement a long-term energy plan for our nation as a whole. Though weather conditions and design flaws in California's electricity restructuring plan contributed, the California electricity crisis is at heart a supply crisis.

Since 1995, California's peak summer demand for electricity has risen by at least 5,500 megawatts (MW), while in-state generation has failed to keep pace. California's generation shortfall did not stem from a lack of interest in building capacity. Since 1997, power producers filed applications to build an additional 14,000 MW of new capacity in California.

In addition to a lack of new generation, a crucial transmission bottleneck in the middle of the state—called Path 15—prevents power in the south from being shipped to the north during emergencies.

This year, reduced hydropower availability due to low rainfall, higher than expected unplanned plant outages, and the financial problems of California's utilities exacerbated this growing supply-demand imbalance. As a result, California's supply problem turned into a crisis, resulting in soaring electricity bills for homes and businesses and rolling blackouts.

In part due to the interconnected nature of the western electricity grid, California's critical electricity shortages have helped to drive up electricity costs in the West.

Unfortunately, there are no short-term solutions to long-term neglect. It can take new power plants and transmission facilities years to site, permit, and construct. Despite expedited federal permitting, California's emergency efforts to increase new generation by 5,000 MW by July appear to be falling short. Less than 2,000 MW of new generation is expected to be in place by summer. Even with aggressive conservation measures, peak demand this summer is projected to outstrip supply by several thousand megawatts. The California grid

operator expects more than 30 days of blackouts.

California officials have warned that the crisis may last several years. Though California's efforts to increase generation may not suffice to prevent blackouts this summer, if continued and strengthened, they promise to limit the duration of the crisis.

Recommendations:

★ The National Energy Policy Development (NEPD) Group recommends that the President issue an Executive Order to direct all federal agencies to include in any regulatory action that could significantly and adversely affect energy supplies, distribution, or use, a detailed statement on (1) the energy impact of the proposed action, (2) any adverse energy effects that cannot be avoided should the proposal be implemented, and (3) alternatives to the proposed action. The agencies would be directed to include this statement in all submissions to the Office of Management and Budget of proposed regulations covered by Executive Order 12866, as well as in all notices of proposed regulations published in the Federal Register.

★ The NEPD Group recommends that the President direct the executive agencies to work closely with Congress to implement the legislative components of a national energy policy.

Conservation and Energy Efficiency

Conservation and energy efficiency are crucial components of a national energy plan. Energy efficiency is the ability to use less energy to produce the same amount of useful work or services. Conservation is closely related and is simply using less energy. Improved energy efficiency and conservation reduces energy consumption and energy costs, while maintaining equivalent service in our homes, offices, factories, and automobiles. Greater energy

efficiency helps the United States reduce energy imports, the likelihood of energy shortages, emissions, and the volatility of energy prices.

Over the last three decades, the United States has significantly improved its energy efficiency by developing and expanding the use of energy efficient technologies. Although our economy has grown by 126 percent since 1973, our energy use has increased by only 30 percent. Had energy use kept pace with economic growth, the nation would have consumed 171 quadrillion British thermal units (Btus) last year instead of 99 quadrillion Btus.

About a third to a half of these savings resulted from shifts in the economy, such as the growth of the service sector. The other half to two-thirds resulted from greater energy efficiency. Technological improvements in energy efficiency allow consumers to enjoy more energy services without commensurate increases in energy demand. The rate at which these efficiency improvements are made varies over time, depending on the extent to which factors—such as energy policies, research and development, prices, and market regulations—encourage the development of new, efficient products and consumer investment in these products. An increased rate of improvement in energy efficiency can have a large impact on energy supply and infrastructure needs, reducing the need for new power plants and other energy resources, along with reduced stress on the energy supply infrastructure.

Load management is the ability to adjust energy loads to reflect immediate supply conditions. In the very short term, direct appeals for conservation can ease strained energy supply markets for a time. Over the longer run, the ability to adjust demand on an as-needed basis can be an important source of energy reserves, resulting in lower energy bills for participating customers.

The impact that improvements in energy efficiency can have on energy supply markets grows over time. Electricity demand is projected to rise by 1.8 percent a year over the next 20 years, requiring the addition of some 393,000 MW of generation capacity. At the same time,

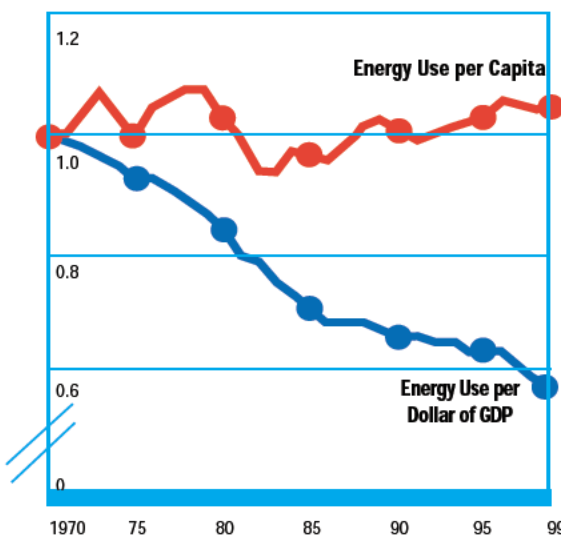
energy efficiency is projected to continue to improve between 2000 and 2020. A decrease in demand from 1.8 percent to 1.5 percent would reduce the need for new generating capacity next year by about 2,000 MW. Extending that reduction over the next 20 years would reduce the need for new generation by 60,000 to 66,000 MW.

While this projection shows that conservation can help ensure the United States has adequate energy supplies for the future, it also shows that conservation alone is not the answer. Even with more conservation, the U.S. will need more energy supplies. Today, new technologies offer new opportunities to enhance our energy efficiency. As these technologies gain market acceptance, they will help ensure a reliable and affordable energy and electric power supply for the nation.

Energy Intensity

The energy intensity of the U.S. economy is measured by the amount of energy used to produce a dollar's worth of gross domestic product (GDP). It now takes only about 56 percent of the energy required in 1970 to produce a

Figure 1-1
U.S. Energy Use per Capita and per Dollar of GDP: 1970–1999
(Index: 1970 = 1)



The energy intensity of the U.S. economy is measured by the amount of energy used to produce a dollar's worth of gross domestic product (GDP). By that yardstick, U.S. energy intensity declined significantly between 1970 and 1985, and has continued to decline, albeit at a slower rate.

Source: U.S. Department of Energy, Energy Information Administration.

Measures of Electrical Power

A watt is a measure of the amount of energy that can be produced during a specific period of time.

- 1 kilowatt (KW)= 1,000 watts
- 1 megawatt (MW)=1million watts
- 1 gigawatt (GW)=1 billion watts
- 1 terawatt (TW)=1 trillion watts

U.S. Energy Efficiency Is Improving

- New home refrigerators now use about one-third less energy than they did in 1972.
- New commercial fluorescent lighting systems use less than half the energy they did during the 1980s.
- Federal buildings now use about 20 percent less energy per square foot since 1985.
- Industrial energy use per unit of output declined by 25 percent from 1980 to 1999.
- The chemical industry's energy use per unit of output has declined by roughly 40 percent in the past 25 years.
- The U.S. government has reduced its energy use in buildings by over 20 percent since 1985.
- The amount of energy required to generate 1 kilowatt-hour of electricity has declined by 10 percent since 1980.

What Causes Transmission Constraints?

When additional electricity flow from one area exceeds a circuit's capacity to carry that flow to another area, the overloaded circuit becomes congested and blocks a steady flow of power. To prevent transmission bottlenecks, system operators curtail transactions between areas or increase generation on the side of the constraint where the electricity is flowing and reduce generation on the opposite side. Transmission constraints result in price differences between regions that exceed differences due to line losses, because electricity can no longer flow freely to the affected area.

A pressing long-term electricity challenge is to build enough new generation and transmission capacity to meet projected growth in demand.

dollar of GDP today (Figure 1-1). This reduction is attributable to improved energy efficiency, as well as to structural changes in the economy, particularly the relative decline of energy-intensive industries.

The decline in the nation's energy intensity accelerated between 1999 and 2000, a period when nonenergy-intensive industries experienced rapid growth. Energy intensity is projected to continue to decline through 2020 at an average rate of 1.6 percent a year. This is a slower rate of decline than experienced in the 1970s and early 1980s, which was characterized by high energy prices and a shift to less energy-intensive industries, but is a more rapid rate of decline than experienced on average during the latter part of the 1980s and the 1990s.

Challenges Confronting Electricity Supply

Our nation's electricity supply has failed to keep pace with growing demand. This imbalance is projected to persist into the future. The adverse consequences have manifested themselves most severely in the West, where supply shortages have led to high prices and even blackouts. In other regions, inadequate supply threatens the reliability and affordability of electric power.

Large amounts of new generating capacity are slated for installation around the country from 2001 to 2004. However, there is a geographic mismatch between where we will generate energy and where it is needed. For example, little capacity is being added where it is most needed, such as in California and eastern New York.



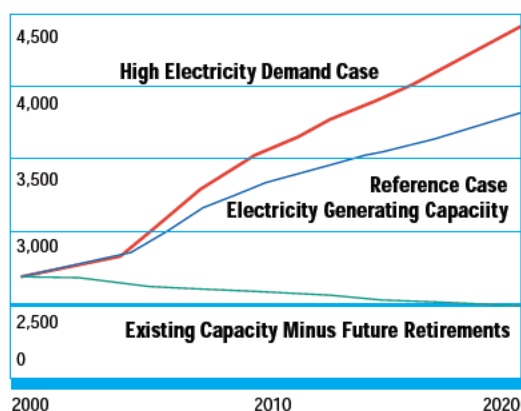
Electricity supply conditions in the Southeast are expected to be tight in the summer of 2001, much as they have been the previous two years. The Northeast may also face supply shortages. If the temperatures of the summer of 2000 had been normal rather than unseasonably cool, New York and New England would most likely have experienced electricity supply shortfalls and price spikes. Critical supply problems could arise if the weather in the summer of 2001 is unusually warm or if plant outages rise above average levels.

Our nation's most pressing long-term electricity challenge is to build enough new generation and transmission capacity to meet projected growth in demand. Across the country, we are seeing the same signs that California faced in the mid-1990s: significant economic regulatory uncertainty, which can result in inadequate supply. This level of uncertainty can vary across the country, depending on state and local regulations. Of the approximately 43,000 MW of new generating capacity that power companies planned in 1994 for construction from 1995 to 1999, only about 18,000 MW were actually built. Although plans have been announced to build more capacity than the country will need over the next five to seven years, this new construction assumes market and regulatory conditions that are not yet assured. Over the next twenty years, the United States will need 1,300 to 1,900 new power plants, which is the equivalent of 60 to 90 new power plants a year (Figure 1-2).

But even with adequate generating capacity, we do not have the infrastructure to ensure reliable supply of electricity. Investment in new transmission capacity has failed to keep pace with growth in demand and with changes in the industry's structure. Since 1989, electricity sales to consumers have increased by 2.1 percent annually, yet transmission capacity has increased by only 0.8 percent annually. As electricity markets become more regional, transmission constraints are impeding the movement of electricity both within and between regions.

The price spikes in the Midwest in the summer of 1998 were in part caused by trans-

Figure 1-2
The U.S. Needs More Power Plants



The nation is going to require significant new generation capacity in the next two decades. Depending on demand, the United States will need to build between 1,300 and 1,900 new power plants—or about one new power plant a week.

Source: U.S. Department of Energy, Energy Information Administration.

mission constraints, which limited the region's ability to import electricity from other regions at a time of high demand. Transmission bottlenecks contributed to the blackouts in California over the past year, and have been a persistent cause of price spikes in New York City during peak demand. Constraints on New England's ability to import low-cost power from Canada could raise electricity prices during periods of high demand.

Electricity is a secondary source of energy, generated through the consumption of primary sources (Figure 1-3). The largest source of U.S. electricity generation is coal, followed by nuclear energy, natural gas, hydropower, oil, and non-hydropower renewable energy.

Coal

Coal is America's most abundant fuel source. The United States has a 250-year supply of coal. Over 1 billion tons of coal were produced in 25 states in 2000. About 99.7 percent of U.S. coal production is consumed domestically, with electricity generation accounting for about 90 percent of coal consumption.

After peaking in 1982, coal prices have generally declined. This trend is projected to continue through 2020, reflecting an expanding shift into lower-cost western coal production and substantial increases in productivity. While coal is expected to

remain the dominant fuel in meeting increasing U.S. electricity demand through 2020, energy policy goals must be carefully integrated with environmental policy goals. The Clean Air Act Amendments of 1990 and related state regulations require electricity generators to reduce emissions of sulfur dioxide and nitrogen oxide.

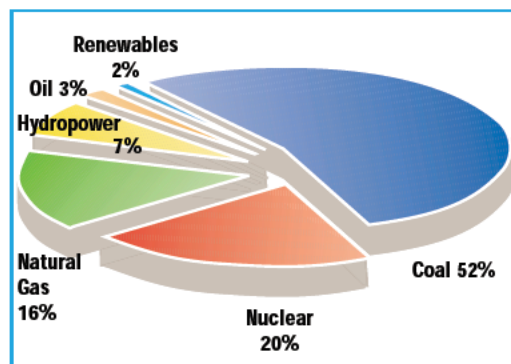
Nuclear Energy

Nuclear energy is the second-largest source (20 percent) of U.S. electricity generation. Nuclear power is used exclusively to generate electricity. Nuclear power has none of the emissions associated with coal and gas power plants, including nitrogen oxides, sulfur dioxide, mercury and carbon dioxide. Costs of electricity generation by nuclear plants compare favorably with the costs of generation by other sources.

While the number of nuclear plants has declined due to retirements, nuclear electricity generation has steadily increased in recent years. Several factors have created a more favorable environment for nuclear energy: safe, standardized plant designs; an improved licensing process; effective safety oversight by the Nuclear Regulatory Commission (NRC); the advent of new technologies; and uncertain, volatile natural gas prices. This more favorable environment has resulted in increased re-licensing of nuclear plants and the consolidation of several plants in the hands of fewer, more experienced operators.

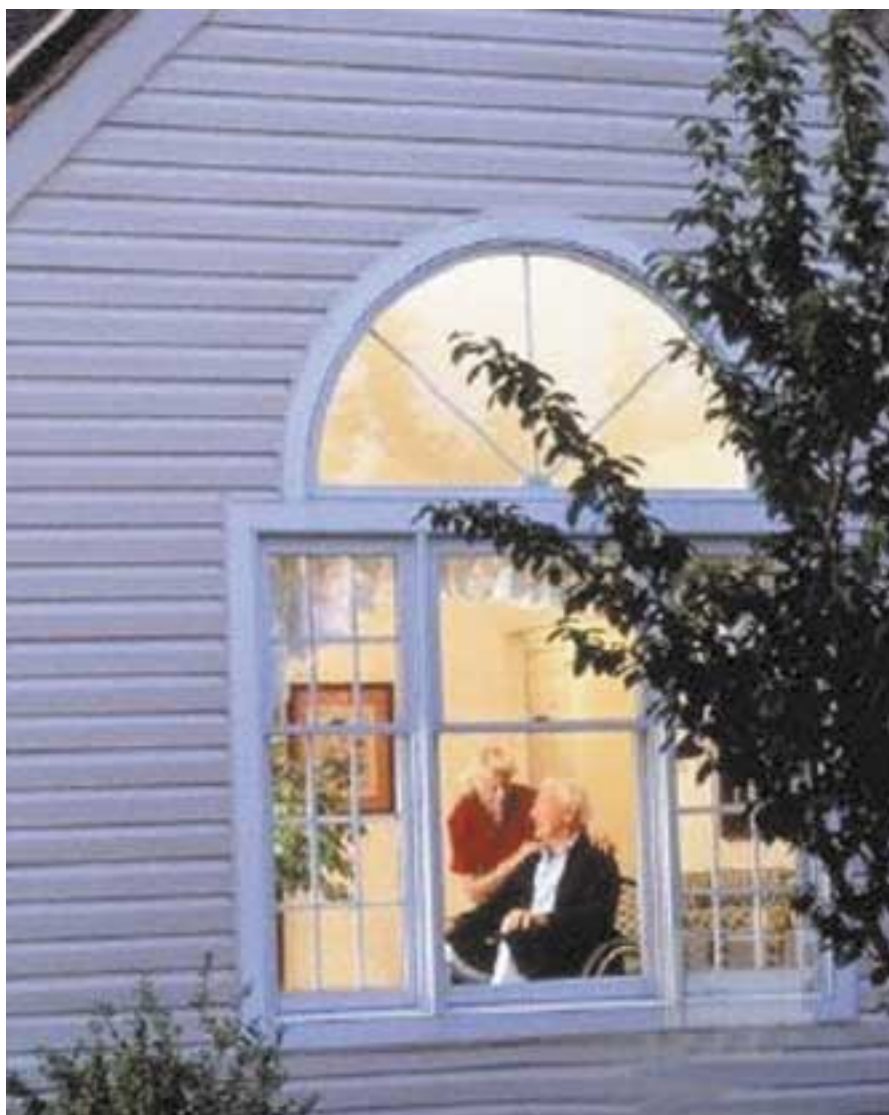
Figure 1-3

Fuel Sources for Electricity Generation in 2000



Electricity is a secondary source of energy, generated through the consumption of primary sources. Coal and nuclear energy account for over 70 percent of U.S. electricity generation.

Source: U.S. Department of Energy, Energy Information Administration.



Many Americans received high heating bills this winter as a result of sharp increases in natural gas prices.

The nuclear industry is closely regulated by the NRC, which provides oversight of the operation and maintenance of these plants. This oversight includes a comprehensive inspection program that focuses on the most significant potential risks of plant operations, and features full-time resident inspectors at each plant, as well as regional inspectors with specialized expertise. In addition to rigorous inspection criteria, the installation of new design features, improvements in operating experience, nuclear safety research, and operator training have all contributed to the nuclear industry's strong safety record.

An important challenge to the use of nuclear energy is the issue of safe and

timely long-term storage of spent nuclear fuel and high- and low-level radioactive waste. Currently, no plans exist to construct any new nuclear plants. However, due to more favorable conditions, the decline in nuclear energy generation has not been as rapid as was predicted only a few years ago, as evidenced by increased re-licensing.

Natural Gas

Natural gas is the third-largest source of U.S. electricity generation, accounting for 16 percent of generation in 2000. Under existing policy, natural gas generating capacity is expected to constitute about 90 percent of the projected increase in electricity generation between 1999 and 2020. Electricity generated by natural gas is expected to grow to 33 percent in 2020—a growth driven by electricity restructuring and the economics of natural gas power plants. Lower capital costs, shorter construction lead times, higher efficiencies, and lower emissions give gas an advantage over coal and other fuels for new generation in most regions of the country.

However, natural gas is not just an electricity source. It is used in many different ways, including as vehicle fuel, as industrial fuel, and in our homes. In addition, natural gas is used as a feedstock during the manufacturing process of such products as chemicals, rubber, apparel, furniture, paper, clay, glass, and other petroleum and coal products. Overall, natural gas accounts for 24 percent of total U.S. energy consumed and for all purposes 27 percent of domestic energy produced.

Eighty-five percent of total U.S. natural gas consumption is produced domestically. The import share of consumption rose from 5 percent in 1987 to 15 percent in 2000, and net imports have comprised more than 50 percent of the growth in gas demand since 1990. Canada, with very large gas supplies and easy pipeline access to the lower 48 states, accounts for nearly all U.S. natural gas imports. Unlike oil, almost all natural gas is produced and sold within the same region. Therefore, prices are determined by regional, rather than global, markets.

In 2000, natural gas prices moved

sharply higher after fifteen years of generally flat prices. Futures prices surged by 320 percent in 2000 to an all-time high of \$9.98 per million Btus in late December 2000—nearly five times higher than the \$2.05 per million Btu average from 1991 to 1999. While prices have declined since the beginning of 2001, they remain much higher than recent levels.

Between 2000 and 2020, U.S. natural gas demand is projected by the Energy Information Administration to increase by more than 50 percent, from 22.8 to 34.7 trillion cubic feet. Others, such as Cambridge Energy Research Associates, expect gas consumption to increase by about 37 percent over that period. Growth is projected in all sectors—industrial, commercial, residential, transportation, and electric generation. More than half of the increase in overall gas consumption will result from rising demand for electricity generation.

Although high natural gas prices have negative effects on consumers, businesses, industries, and the economy as a whole, they also promote more rapid development and adoption of new energy efficient technologies, investment in distribution systems, and greater investment in exploration and development. Although these market responses do not occur rapidly enough to prevent near-term price spikes, over time, they help to hold down prices.

As a result of the sharp increase in natural gas prices, many consumers received historically high utility bills this winter. The price spike has had a particularly severe impact on low-income consumers who use natural gas for heating. In recent months, 5 million consumers have applied for federal and state assistance to pay their heating bills—an increase of 1 million consumers over last year.

The projected rise in domestic natural gas production—from 19.3 trillion cubic feet in 2000 to 29.0 trillion cubic feet in 2020—may not be high enough to meet projected demand. In the near term, incremental production of natural gas is expected to come primarily from unconventional sources in the Rocky Mountain, Gulf Coast, and mid-continent regions; the North Slope of Alaska; and the offshore Gulf of Mexico. Onshore federal lands currently contribute

about 10 percent of U.S. production, and federal offshore production contributes about 26 percent.

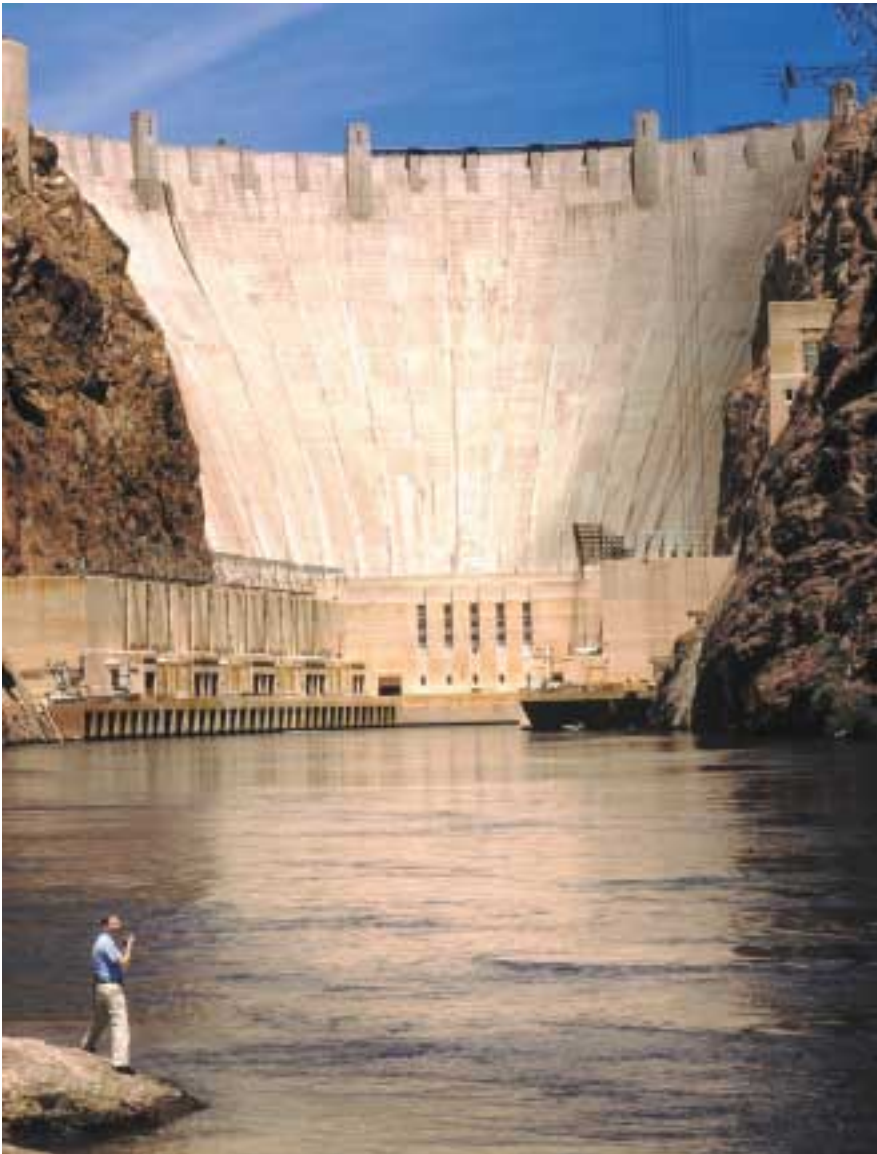
The most significant long-term challenge relating to natural gas is whether adequate supplies can be provided to meet sharply increased projected demand at reasonable prices. If supplies are not adequate, the high natural gas prices experienced over the past year could become a continuing problem, with consequent impacts on electricity prices, home heating bills, and the cost of industrial production. These concerns will redouble if policy decisions sharply reduce electricity generation by any other source, since it is doubtful that natural gas electricity generation could expand to the extent necessary to compensate for that loss of generation.

To meet this long-term challenge, the United States not only needs to boost production, but also must ensure that the natural gas pipeline network is expanded to the extent necessary. For example, although natural gas electricity generation in New England is projected to increase by 16,000 MW through 2000, bottlenecks may block the transmission of necessary supplies. Unless pipeline constraints are eliminated, they will contribute to supply shortages and high prices, and will impede growth in electricity generation.

Hydropower

Hydropower is the fourth-largest source of U.S. electricity generation, accounting for about 7 percent of total generation in 2000. In some regions of the country, such as the Northwest and New York, hydropower makes a much bigger contribution to electricity generation. Although the United States is second only to Canada in hydropower generation, hydropower generation has remained relatively flat in the United States for years.

Hydropower has significant environmental benefits. It is a form of low-cost electricity generation that produces no emissions, and it will continue to be an important source of U.S. energy for the future. Given the potential impacts on fish and wildlife, however, it is important to ef-



Hydropower is the fourth-largest source of U.S. electricity generation. The most significant challenge confronting this source of energy is regulatory uncertainty regarding the federal licensing process.

ficiently and effectively integrate national interests in both natural resource preservation and environmental protection with energy needs.

There are two categories of hydropower projects in the United States: (1) those operated by federal electric utilities, such as the federal power marketing administrations (Bonneville, Western, Southwestern, and Southeastern); and (2) the approximately 2,600 non-federal hydropower dams licensed or exempted by the Federal Energy Regulatory Commission (FERC). The federal utilities have large hydropower systems operated by the Bureau of Reclamation and Army Corps of Engineers, and play an important role meeting electricity

demand, especially in the Northwest and the West. Hydropower projects operate with multiple purposes, such as electricity generation, flood control, navigation, and irrigation.

Although most potential for hydropower has already been developed, there is some undeveloped hydropower capacity in the United States. Much of this capacity could be expanded without constructing a new dam.

The most significant challenge confronting hydropower is regulatory uncertainty regarding the federal licensing process. The process is long and burdensome, and decision-making authority is spread across a range of federal and state agencies charged with promoting different public policy goals. Reforms can improve the hydropower licensing process, ensuring better public participation, ensuring that effective fish and wildlife conditions are adopted, and providing interagency resolution before conflicting mandatory license conditions are presented. The licensing process needs both administrative and legislative reforms. In addition, FERC should be encouraged to adopt appropriate deadlines for its own actions during the process.

Oil

Oil accounts for approximately 3 percent of electricity generation. Oil is used as a primary source to fire electricity generation plants in some regions. Specifically, oil is an important source of electricity in Hawaii, Florida, and some northeastern states. Oil can also be used as an additional source of fuel for electricity generation in plants that can use either natural gas or oil. However, electricity generation from oil is projected to decline to about one-half of one percent of total electricity generation by 2020.

Renewable Energy: A Growing Resource

Renewable energy technologies tap natural flows of energy—such as water, wind, solar, geological, and biomass sources—to produce electricity, fuels, and heat. Non-hydropower renewable electricity generation is projected to grow at a faster rate

than all other generation sources, except natural gas. These sources of energy are continuously renewable, can be very clean, are domestically produced, and can generate income for farmers, landowners, and others. Although its production costs generally remain higher than other sources, renewable energy has not experienced the price volatility of other energy resources.

Non-hydropower renewable energy sources currently account for only about 4 percent of total energy consumption and 2 percent of total electricity generation. The sources of non-hydropower renewable electricity generation are biomass (the direct combustion of plant matter and organic residues, such as municipal solid waste use); geothermal (use of naturally occurring steam and hot water); wind; and solar. Biomass and geothermal account for most renewable electricity generation.

The most important long-term challenge facing renewable energy remains economic. Renewable energy costs are often greater than those of other energy sources. However, these costs have declined sharply in recent years, due to improved technology. If this trend continues, renewable energy growth will accelerate. By 2020, non-hydropower renewable energy is expected to account for 2.8 percent of total electricity generation.

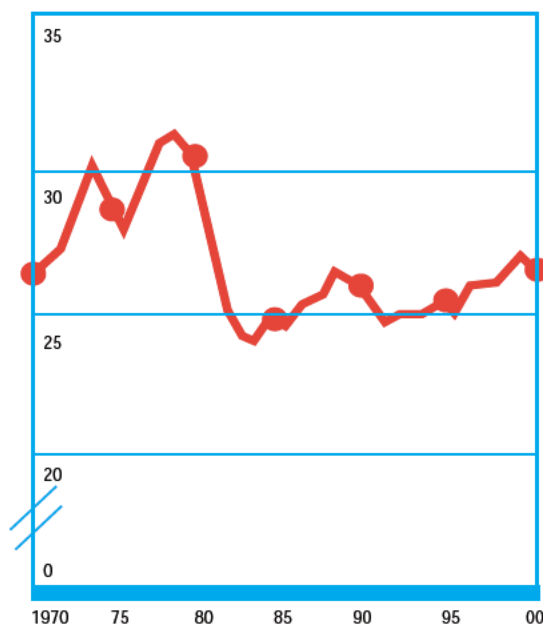
Transportation Energy Needs

Oil is the nation's largest source of primary energy, serving almost 40 percent of U.S. energy needs. In 2000, the United States consumed an average of 19.5 million barrels of oil every day. Transportation fuels account for about two-thirds of our oil consumption, and the industrial sector for 25 percent. Residential and commercial uses, such as heating oil and propane—important fuels in the Northeast and Midwest—account for most of the rest.

The share of oil in U.S. energy supply has declined since the early 1970s, the result of growth in other fuels, particularly coal and nuclear. Per capita oil consumption, which reached a peak in 1978, has fallen by 20 percent from that level (Figure 1-4).

Figure 1-4
**U.S. Per Capita Oil
Consumption: 1970–2000**

(Barrels per Year)



Per capita oil consumption reached a peak in 1978 of 31 barrels. It has fallen by 20 percent since then to 26 barrels per capita.

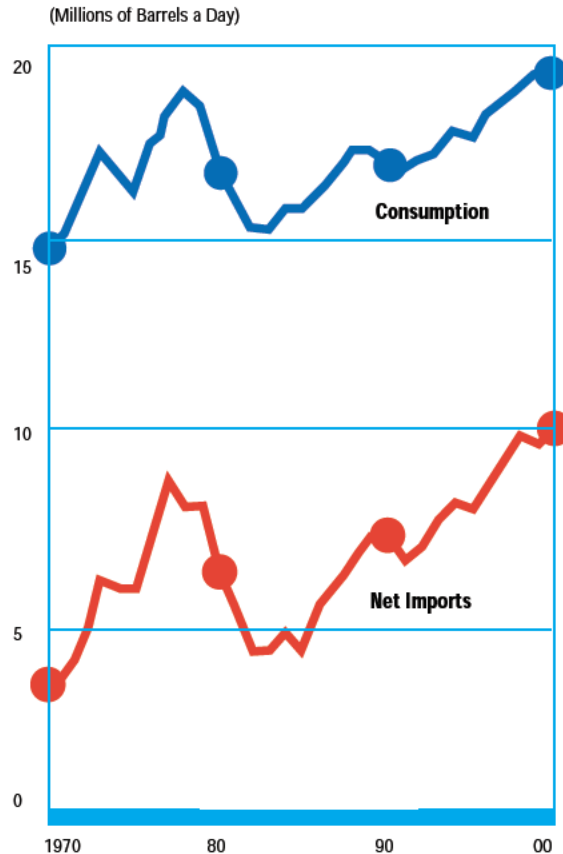
Source: U.S. Department of Energy, Energy Information Administration

Renewable energy technologies tap natural flows of energy to produce electricity, fuels, and heat.

U.S. DEPARTMENT OF ENERGY, NATIONAL
RENEWABLE ENERGY LABORATORY



Figure 1-5
Dependence on Foreign Sources of Oil



U.S. dependence on oil imports is a serious long-term challenge. The economic security of our nation and our trading partners will remain closely tied to global oil market developments.

Source: U.S. Department of Energy, Energy Information Administration.

In 2020, oil is projected to account for roughly the same share of U.S. energy consumption as it does today.

The United States has been a net importer of energy since the 1950s, and U.S. dependence on imports has grown sharply since 1985 (Figure 1-5). Today, oil accounts for 89 percent of net U.S. energy imports. Net oil imports account for most of the rise in energy imports since the mid-1980s, and have grown from about 4.3 million barrels per day (bpd) in 1985 to 10 million bpd in 2000.

World oil prices have been marked by notable price volatility over the past several years. For example, the average initial purchase price of crude oil rose from \$8.03 a barrel in December 1998 to \$30.30 a barrel in November 2000. Spot prices rose even higher. This dramatic price swing was the product of several events. A series of production cuts by the Organization of Petroleum Exporting Countries (OPEC) in 1998 and 1999 sharply curtailed global oil supplies. At the same time, rebounding demand for oil in Asia following roughly two years of economic weakness, and rapid economic growth in the United States boosted oil consumption and squeezed supplies even further. By September 2000, oil prices peaked as markets faced limited supply of crude and petroleum products



Domestic oil supply cannot be increased unless several access and infrastructure challenges are addressed. For example, U.S. refining and pipeline capacity has not kept pace with increasing demand for petroleum products.

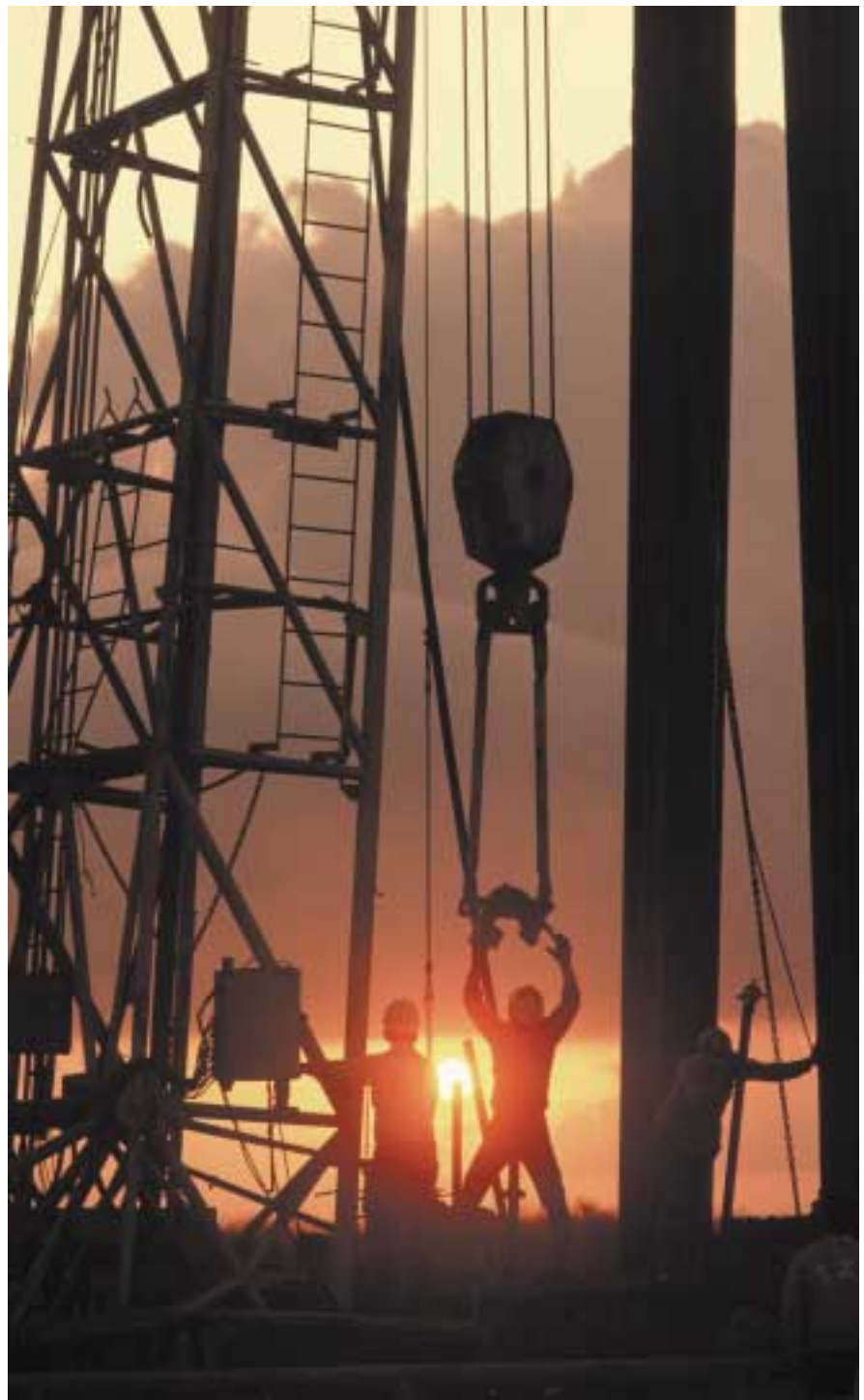
ahead of the winter season, when demand is typically higher. In December 2000, oil prices fell after the market absorbed the impact of a series of OPEC production increases.

This recent price volatility illustrates the effect of intermittent market power exerted by cartel behavior in a global petroleum market. Moreover, prices are set in a market where supply is geographically concentrated. Almost two-thirds of world proven reserves are in the Middle East. Elsewhere, Central and South America account for 9 percent; Africa, 7 percent; North America, 5 percent; Eastern Europe and the former Soviet Union, 5 percent; the rest of Asia, 4 percent; and Western Europe, 2 percent. OPEC's huge oil reserves and production capacity and its periodic efforts to influence prices add to volatility in the market.

Oil prices are expected to remain high through 2002, affecting the cost of transportation, heating, electricity generation, and industrial production. High oil prices mean high prices for petroleum products, such as gasoline, diesel fuel, heating oil, propane, and jet fuel. The summer 2001 base case average gasoline price from the Department of Energy *Short-Term Energy Outlook* is \$1.49 per gallon. However, prices have risen more rapidly than anticipated since the report's release, and a much higher summer average in the range of \$1.50 to \$1.65 per gallon is likely. Some areas have already experienced gasoline prices above \$2.00 per gallon. Gasoline inventories going into the driving season are projected to be lower than last year, which could set the stage for regional supply problems that once again create significant price volatility in gasoline markets.

Price Volatility in Gasoline Markets

During the early summer of 2000, low inventories set the stage for a gasoline price run-up in the Midwest. Several pipeline and refinery problems sent marketers scrambling for limited supplies of both reformulated gasoline (RFG) and conventional gasoline, driving prices up rapidly. In Chicago, the spot price for blend stock for RFG, ex-



cluding ethanol, doubled in about six weeks, from 83 cents per gallon on April 25 to \$1.65 on June 7. Spot prices then fell back over the next five weeks to 84 cents on July 12 as extra supply began arriving. Retail regular-grade RFG prices in the Midwest rose from \$1.47 on April 24 to just over \$2.00 per gallon on June 19, before falling back to \$1.43 by July 24, showing the typical tendency of

Because the United States is a mature oil-producing region, production costs are often higher than in foreign countries.

retail prices to lag spot price changes.

Refiners face additional challenges as a result of various state and local clean fuel requirements for distinct gasoline blends (“boutique fuels”). These different requirements sometimes make it difficult, if not impossible, to draw on gasoline supplies from nearby areas or states to meet local needs when the normal supply is disrupted.

In 2000, very low inventories of gasoline and other refined products on the U.S. East and Gulf coasts increased the market’s susceptibility to external shocks, such as operating problems in refineries or pipelines, or short-term surges in demand. Last winter, heating oil prices were at near-record levels. During 2000, the federal government reduced the vulnerability of the Northeast to heating oil shortages, such as those experienced in January 2000, by creating a 2-million-barrel heating oil reserve in New Jersey and Connecticut.

Because the United States is a mature oil-producing region, production costs are often higher than in foreign countries, particularly OPEC countries. In addition, access to promising domestic oil reserves is limited. U.S. oil production in the lower 48 states reached its peak in 1970 at 9.4 million bpd. A surge in Alaskan North Slope oil production beginning in the late 1970s helped postpone the decline in overall U.S. production, but Alaska’s production peaked in 1988 at 2 million bpd, and fell to 1 million bpd by 2000. By then, U.S. total oil output had fallen to 5.8 million bpd, 39 percent below its peak.

By 2020, U.S. oil production is projected to decline from 5.8 to 5.1 million bpd under current policy. However, oil consumption is expected to rise to 25.8 million bpd by 2020, primarily due to growth in consumption of transportation fuels. Given existing law, production from offshore sources, particularly the Gulf of Mexico, is predicted to play an increasingly important role in the future, accounting for a projected high of 40 percent of domestic oil production by 2010, up from 27 percent today. Technological advances can mitigate the decline in U.S. oil production by enhancing recovery from domestic oil reserves and

lowering production costs.

Our projected growing dependence on oil imports is a serious long-term challenge. U.S. economic security and that of our trading partners will remain closely tied to global oil market developments. Without a change in current policy, the share of U.S. oil demand met by net imports is projected to increase from 52 percent in 2000 to 64 percent in 2020. By 2020, the oil for nearly two of every three gallons of our gasoline and heating oil could come from foreign countries. The sources of this imported oil have changed considerably over the last thirty years, with more of our imports coming from the Western Hemisphere. Despite progress in diversifying our oil suppliers over the past two decades, the U.S. and global economies remain vulnerable to a major disruption of oil supplies.

The Strategic Petroleum Reserve (SPR), the federal government’s major tool for responding to oil supply disruptions, has not kept pace with the growth in imports. The number of days of net oil import protection provided by the Reserve declined from 83 days of imports in 1992 to 54 days of imports today. Net domestic oil imports have increased significantly since 1992, while the SPR’s oil inventory actually decreased.

Domestic oil supply cannot be increased unless several access and infrastructure challenges are addressed. U.S. refining and pipeline capacity has not kept pace with increasing demand for petroleum products. Unless changes take place, the net effect will likely be increased imports, regionally tight markets, and circumstances in which prices for gasoline, heating oil, and other products rise independently of oil prices.

Greater price volatility for gasoline, diesel fuel, heating oil, propane, and jet fuel is likely to become a larger problem over time, unless additional refining capacity and expanded distribution infrastructure can be developed at the same time cleaner products are required. Increasing domestic oil production and reducing demand, particularly for transportation fuels, will re-

quire adoption of a comprehensive national energy policy.

Alternative Transportation Fuels

Development of alternative fuels such as ethanol and other biofuels (liquid fuels derived from organic matter, such as crops), natural gas, and electricity, can help diversify the transportation sector that is so reliant on oil.

Ethanol, a biofuel based on starch crops such as corn, is already making a significant contribution to U.S. energy security, displacing more oil than any other alternative fuel. Other biofuels, such as biodiesel, which can be made from soybean, canola oils, animal fats, and vegetable oils, are making an increasingly important con-

tribution

The success of the federal alternative fuels program has been limited, however. The program focuses on mandating that certain fleet operators purchase alternative fueled vehicles. The hope was that this vehicle purchase mandate would lead to expanded use of alternative fuels. That expectation has not been realized, since most fleet operators purchase dual-fueled vehicles that operate on petroleum motor fuels. Reforms to the federal alternative fuels program could promote alternative fuels use, such as expanding the development of an alternative fuels infrastructure.

Summary of Recommendations

Taking Stock: Energy Challenges Facing the United States

★ The NEPD Group recommends that the President issue an Executive Order to direct all federal agencies to include in any regulatory action that could significantly and adversely affect energy supplies, distribution, or use, a detailed statement on: (1) the energy impact of the proposed action, (2) any adverse energy effects that cannot be avoided should the proposal be implemented, and (3) alternatives to the proposed action. The agencies would be directed to include this statement in all submissions to the Office of Management and Budget of proposed regulations covered by Executive Order 12866, as well as in all notices of proposed regulations published in the Federal Register.

★ The NEPD Group recommends that the President direct the executive agencies to work closely with Congress to implement the legislative components of a national energy policy.

★ The NEPD Group recommends to the President that the NEPD Group continue to work and meet on the implementation of the National Energy Policy, and to explore other ways to advance dependable, affordable, and environmentally responsible production and distribution of energy.

Note: All recommendations in this report are subject to execution in accordance with applicable law. Legislation would be sought where needed. Also, any recommendations that involve foreign countries would be executed in accordance with the customs of international relations, including appropriate diplomatic consultation.

Regional U.S. Energy Challenges

MIDWEST

Energy consumption in the Midwest is dominated by the industrial sector, the sector with the fastest-growing consumption rate through 2020. The transportation sector has the second-fastest consumption growth rate through 2020. States are affected by higher prices for natural gas, propane, and gasoline, and they expect gasoline price spikes this summer. Electricity supplies in some parts of the region may be tight during peak summer demand. High energy prices will drive up farm operating costs, particularly for fertilizer, irrigation, grain drying, and fuel for tractors.

Illinois consumers are reeling from high heating and cooling costs. Landlords are forced to pass on these costs in the form of higher rents. Farmers face low commodity prices, high fuel costs, and dramatically higher fertilizer costs. A key refinery is closing in part because of the cost of meeting cleaner-burning gasoline requirements.

Minnesota's residential electricity use has increased due to population growth and a healthy economy.

Iowa imports over 90 percent of its energy. Farmers are paying twice the 1999 price of fertilizer because of higher prices for natural gas, which is a major component in the fertilizer production.

WEST

Energy consumption in the West is dominated by the transportation sector, which is followed closely by the industrial sector. The region's drought emergency is exacerbating an already challenging energy picture. California is likely to experience more severe electricity blackouts this summer. The Pacific Northwest faces a major shortage of hydropower generation due to low water levels. Electricity prices will remain high in the West until more supply is added. Gasoline could be in short supply this summer in California and other states.

California's energy consumption has grown by about 7 percent a year, while production has remained flat. The point has been reached where demand is occasionally exceeding supply, which has caused rolling blackouts. The situation is likely to worsen this summer when demand will peak.

Oregon's lowest snow pack in history will result in the most severe short-term electricity problem in decades. The state will face high spot market prices and reports the highest gasoline prices in the country.

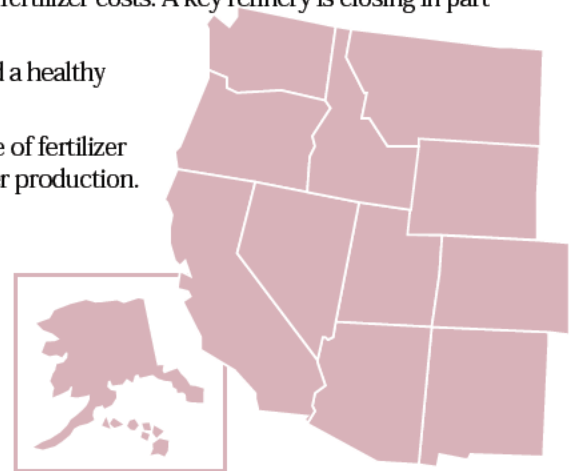
Washington businesses are closing down or cutting back on production. Electricity costs of \$400 per unit compared to \$35 a year ago contributed to the closure of a major paper plant employing 800 employees.

Colorado small business are suffering as well. A 169 percent jump in natural gas prices in one year may force small businesses to close.

Idaho utilities are offering to pay their irrigation customers to not farm portions of their fields to reduce electricity demand and make that saved power available for other local customers. The low snow pack has reduced water in river systems needed for hydropower generation.

Hawaii's geographic isolation contributes to its many energy issues, such as importing 100 percent of its energy, its disproportionately high consumption of jet fuel and heavy reliance on tourism, and its dependence on imported oil for over 90 percent of its primary energy, the majority from sources in the Asia-Pacific region. Electricity is produced mainly from oil, including residuals and distillates from refineries and coal. Because the Islands' electric grids are not interconnected, electric utilities must operate with high reserve margins.

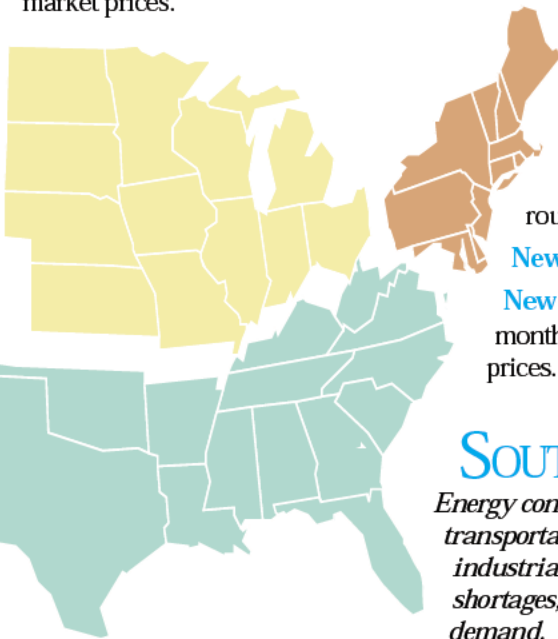
Nevada is covered in large part by federal lands that require federal approval for permitting new transmission and generation facilities. The permitting process can be protracted and cumbersome, despite efforts by federal agencies to streamline and coordinate. The desert climate requires both heating and cooling, the cost of which can be burdensome. While the desert climate is also conducive to geothermal, wind, and solar technologies, additional work is needed to make these technologies economically competitive.



NORTHEAST

Energy consumption in the Northeast is dominated by the transportation sector. Forecasts developed by the Energy Information Administration indicate that the transportation sector will also remain the dominant sector with the fastest-growing consumption rate through 2020. Northeast states' energy challenges include reducing vehicle pollution and interstate transport of power plant emissions. Heavy dependence on heating oil results in disproportionate impacts during cycles of high prices. Energy supplies in the region are limited by electric transmission and gas pipeline bottlenecks.

New York is rushing to complete 11 small natural gas turbines to avoid blackouts in New York City this summer, where customers pay market prices.



Delaware needs upgraded transmission lines to handle increasing loads.

Traditional distributed generation using diesel generators may address these shortfalls, but could raise environmental problems.

Connecticut expects no power shortages this summer, but brownouts are possible if there is a prolonged spike in energy use while power plants are shut down for routine maintenance.

New Hampshire must conserve power on hot days to avoid summer blackouts.

New Jersey regulators have had to allow utilities to raise natural gas rates by 2 percent a month through July 2001 to make up for money lost during the winter due to high fuel prices.

SOUTH

Energy consumption in the South is dominated by the industrial sector, followed by the transportation sector. The transportation sector, however, is expected to grow faster than the industrial sector through 2020. While no state in the region anticipates summer power shortages, electricity supplies in parts of the region may be tight during peak summer demand.

Arkansas' costs of natural gas and propane have doubled and then tripled, contributing to employee layoffs.

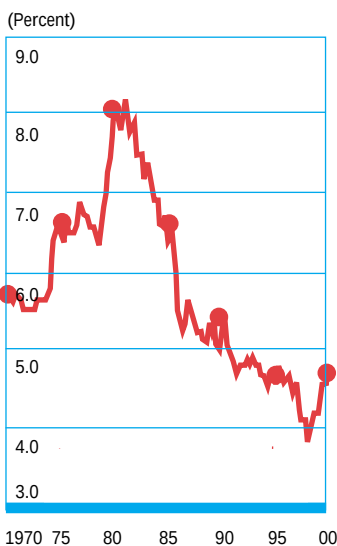
Oklahoma's second-largest industry is the oil and gas industry. The volatility of oil and gas markets can severely affect Oklahomans and the state's economy.

Striking Home

The Impacts of High Energy Prices on Families, Communities, and Businesses

American families, communities, and businesses all depend on reliable and affordable energy for their health, safety, and livelihood. Energy is a critical component of nearly everything that affects our daily lives, from transportation to communication, from food production to medical services, and from air conditioning to heating. Americans expect these services to enhance our lives, and are keenly aware that each additional, unanticipated energy expense is a decrease in funds available for other needs.

Figure 2-1
Income Spent on Energy



Until recently, the share of disposable household income spent on energy steadily declined, falling to a low of 3.8 percent at the end of 1998. Higher prices for oil and other energy products and record cold temperatures in late 2000 bumped this share up to 4.8 percent in the fourth quarter.

Note: Plotted quarterly through the fourth quarter of 2000.

Source: U.S. Department of Commerce, Bureau of Economic Analysis.

Recommendation:

★ The NEPD Group recommends that the President direct the Secretary of Energy to explore potential opportunities to develop educational programs related to energy development and use. This should include possible legislation to create public education awareness programs about energy. Such programs should be long-term in nature, should be funded and managed by the respective energy industries, and should include information on energy's compatibility with a clean environment.

Impacts of High Energy Prices on the Daily Lives of Americans

Many American families and businesses have already felt the strain of rising prices and unreliable energy supplies. Every time energy prices rise, American families have fewer dollars available to meet their needs. Low-income households, energy-intensive industries, and

farmers generally find it difficult to make rapid adjustments to energy price increases.

Rising oil prices act like a tax by foreign oil exporters on Americans. Changing energy prices impose economic costs, such as forcing plants to change schedules, replace machinery, or even shut down. These costs can eventually impact economic growth. So far, increased capital investment by domestic energy producers has offset only a small part of the dampening effects of higher energy costs on consumer spending.

Families

Energy bills for the 74 million middle-class American households consist primarily of home and transportation related expenses. Heating and cooling expenses represent about 40 percent of household energy costs. Other energy expenses include costs for lighting, hot water, appliances, and transportation.

For almost twenty years, the share of household income that Americans spent on their energy needs steadily declined. However, between 1998 and the end of last year, family spending on energy rose by more than 26 percent, from 3.8 to 4.8 percent of after-tax income (Figure 2-1).

Last winter, heating bills for many families tripled. Roughly 50 percent of American families heat their homes with natural gas. Because the last two months of 2000 were particularly cold in some parts of the country, heating bills increased significantly relative to the previous winter. Last winter, average natural gas heating costs in the Midwest increased by 73 percent, from \$540 to \$933. New Englanders' heating bills rose by 27 percent, from \$760 to \$967.





Higher energy prices have forced some energy-intensive manufacturing industries to halt or scale back production and lay off workers.

Many working households can usually accommodate such increases in energy by cutting back on other needs. However, low-income households often have more difficult choices to make. Energy costs for an average low-income household could total 14 percent of family income during the winter of 2000–01, up from about 11 percent for the previous winter. In contrast, energy costs typically represent only about 4 percent of a middle-class family's household budget.

The Low Income Home Energy Assistance Program (LIHEAP) is a federal block grant program that helps low-income consumers pay their energy bills. Last winter, 1.2 million more American families applied for LIHEAP assistance to pay their heating bills, bringing the total close to 5 million American families—up by 26 percent over last year's 3.9 million applicants. As many as 3.6 million families in eighteen states and the District of Columbia risk being unable to pay their bills and having their energy cut off because of the effects of rapidly increasing energy costs.

Recommendations:

★ The NEPD Group recommends that the President take steps to mitigate impacts of high energy costs on low-income consumers. These steps would include:

- Strengthening the Low Income Home Energy Assistance Program by making \$1.7 billion available annually. This is an increase of \$300 million over the regular FY 2001 appropriation.
- Directing the Secretaries of Interior and Health and Human Services to propose legislation to bolster LIHEAP funding by using a portion of oil and gas royalty payments.
- Redirecting royalties above a set trigger price to LIHEAP, whenever crude oil and natural gas prices exceed that trigger price, as determined by the responsible agencies.

★ The NEPD Group recommends that the President increase funding for the Weatherization Assistance Program by \$1.2 billion over ten years. This will roughly double the spending during that period on weatherization. Consistent with that commitment, the FY 2002 Budget includes a \$120 million increase over 2001. The Department of Energy will have the option of using a portion of those funds to test improved implementation approaches for the weatherization program.

★ The NEPD Group recommends that the President support legislation to allow funds dedicated for the Weatherization and State Energy Programs to be transferred to LIHEAP if the Department of Energy deems it appropriate.

The low-income elderly are particularly vulnerable to disruptions in energy supply. If they keep their homes at a reasonable temperature, the high cost of electricity may make it difficult for them to pay their higher electricity bills. This could further result in an elimination of service. Another summer of very hot weather and high energy bills could cause serious health problems for some Americans, particularly those sensitive to high temperatures.

The Department of Energy's Weatherization Assistance Program has reduced the heating and cooling costs of low-income households by weatherizing more than 5 million homes since its inception in 1976. The President has requested \$1.2 billion in additional funding for this program over ten years, roughly double the current level of spending. Consistent with that commitment, the 2002 budget will include a \$120 million increase over 2001.

The Department of Energy's Weatherization Assistance Program

The energy burden on low-income households, as a proportion of income, is four times greater than for other American households. The Weatherization Program provides grant funding for a network of all states and some 970 local weatherization agencies to provide insulation, duct system improvements, furnace upgrades, and other cost-effective, energy-saving improvements based on the energy needs of each home weatherized. Currently, each dollar spent on home weatherization generates \$2.10 worth of energy savings over the life of the home; with additional economic, environmental, health, and safety benefits associated with the installations and resulting home improvements. Typical savings in heating bills, for a natural gas heated home, grew from about 18 percent in 1989 to 33 percent today.

Businesses

For businesses, higher energy prices and disruptions in energy supply may increase inflation and reduce profits, production, investment, and employment. The im-

fact of higher energy prices takes two forms: the higher costs of paying for the energy to run the business, and the higher costs when raw fuel sources are used in manufacturing.

In some energy-intensive industries, rising energy prices have had a significant effect on product prices and operations. For instance, while nonenergy producer prices at the intermediate stage of processing have risen by only 3.6 percent since December 1998, prices of industrial materials and plastic resins, which use petroleum inputs, are up 14 and 23 percent, respectively. DuPont, the leading U.S. producer of plastics, chemicals, and fibers derived from oil and natural gas, faced an increase of \$1.3 billion in raw material costs last year, the largest increase in the industry in a decade. The company expects further disruptions this year due to high energy costs.

The Federal Reserve has reported that businesses have experienced higher energy costs for a number of months, but have been unable to pass these increases on to customers due to intense foreign and domestic competition and slowing demand. On March 7, 2001, the Federal Reserve reported that businesses across the country experienced higher fuel and other energy costs in February 2001, but most businesses were unwilling or unable to pass these costs on to consumers.

This absorption of much of the higher costs of energy has deteriorated the profit

margins of many businesses. About one-quarter of the increase in total unit costs of nonfinancial, nonenergy corporations in the final quarter of last year reflected a rise in energy costs. A more moderate pace of consumer spending, due in part to higher energy prices (natural gas in particular) also contributed to the margin squeeze. The reduction in businesses' purchasing power has also constrained outlays for plants and equipment and most likely intensified the slowdown in business investment that occurred in the last half of 2000.

Energy-intensive manufacturing industries are very sensitive to changes in energy prices, and adjust their production accordingly. Some companies have been forced to halt or scale back production and lay off workers. Others have deemed it more profitable to sell their energy than to produce their products. In the Pacific Northwest, Georgia-Pacific's paper mill closed down and laid off 800 workers until diesel generators could be installed. In recent months, the company's average power costs soared from \$1.2 million to \$10 million.

For other industries, such as computer-driven service industries, energy is not an important component of the total cost. However, many such businesses require a high-quality, reliable source of power. Even a brief loss of power can impose significant costs on high-technology firms.

Energy supply disruptions also impose costs on firms when products or prod-



Disruptions in the supply of energy impose hardships on businesses when products or product inputs are damaged or destroyed, or when production runs are interrupted.



Many companies have been unable to pass higher energy costs on to their customers, which has sharply reduced their profit margins.



Farmers have been hit especially hard by higher fuel and oil prices, which accounted for over a third of the rise in the cost of running their farms.

uct inputs are damaged or destroyed, or when production runs are interrupted. For example, a survey of small businesses conducted by the National Federation of Independent Business in February, 2001, found that more than half of the firms surveyed that had experienced blackouts this year in California were forced to reduce or shut down business operations altogether during the blackouts. About one-third lost sales, almost 21 percent said materials were damaged or destroyed, and nearly 40 percent had to absorb wage costs for work that was not completed.

For businesses that seek to mitigate energy price volatility, an important factor is access to derivatives markets. Both exchange-traded futures and over-the-counter derivative contracts allow firms to substantially reduce their exposure to changes in energy prices. A wide variety of highly liquid futures contracts on energy products such as oil, natural gas, and electricity allow energy users and market participants to reduce or add financial exposure to energy prices. More so-

phisticated and customizable products are available in the over-the-counter derivative markets. As these markets become increasingly liquid and efficient, more firms will take advantage of these products, reducing the economy's sensitivity to shifts in energy prices. However, most small businesses currently lack the resources or sophistication to take advantage of these products, and will therefore remain vulnerable to rising energy costs. The U.S. government should continue to support the development of efficient derivatives markets.

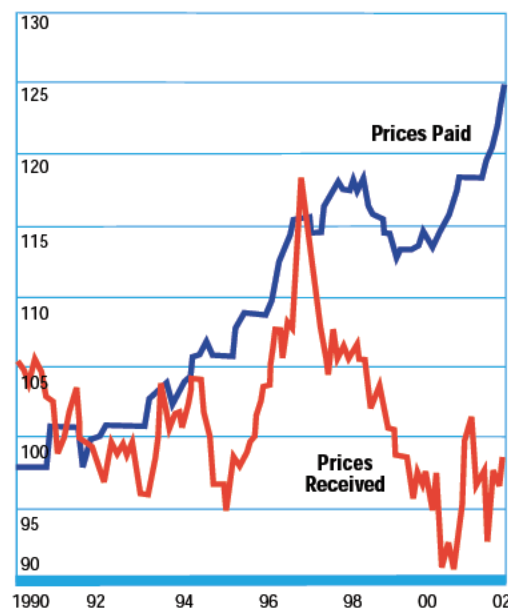
Agriculture

Farmers need ample, affordable energy to run their machinery and equipment. Today, farm production costs are rising sharply, while farm income remains low. Increasing oil prices and interest rates, along with higher prices for other production inputs (including hired labor), boosted farmers' production expenses by 4 percent, or \$7.6 billion, in 2000. The rise in farm production expenses has occurred at a time of continued weakness in the prices farmers receive for their products (Figure 2-2).

Higher fuel and oil prices accounted for over one-third of the increase in farm

Figure 2-2
Farmers Are Being Squeezed by Energy Prices

(Index: 1990-92 = 100)



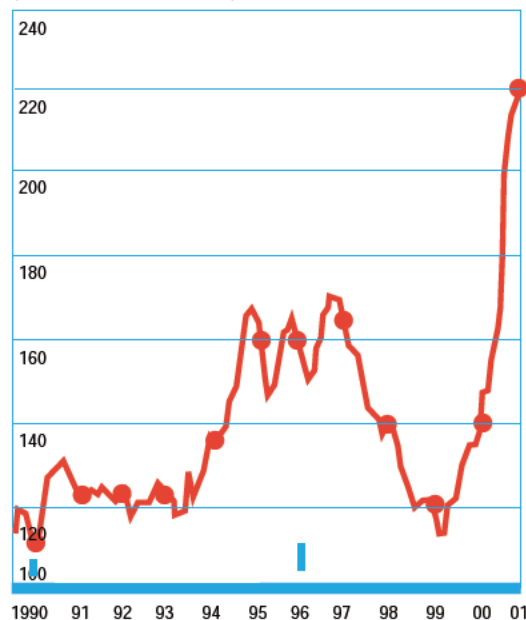
Costs for fuel, fertilizer, and electricity have boosted total prices paid by farmers, while prices farmers receive for their products have remained weak.

Note: Prices paid are for goods, services, interest, taxes, and wages; prices received are for all farm products.

Source: U.S. Department of Agriculture.

Figure 2-3
Farm Costs Are Increasing

(Index: December 1979 = 100)



Rising energy prices had a significant effect on product prices in some industries that are heavily dependent on energy inputs. The most dramatic example is the 90 percent increase in the price of nitrogenous fertilizer since December 1998.

Source: U.S. Department of Labor.

production costs. Retail diesel prices this past winter were \$1.60 a gallon, compared to about \$1.40 a year ago and only \$1.00 two years ago. Propane prices were over \$1.60 a gallon this winter, compared to \$1.10 a year ago. And, natural gas prices hit \$10.00 per million Btus in January, after averaging about \$2.50 for most of 1998–99. Although natural gas prices have declined, they remain much higher than earlier levels.

Natural gas is an important component of farm production costs. For example, it is used to dry grain, heat farm buildings, and run food-processing equipment. Heating costs for poultry producers soared last winter, sharply reducing earnings.

Natural gas also is a major component in the production of fertilizers, pesticides, and other farm chemicals. It accounts for 70 to 90 percent of the cost of producing anhydrous ammonia, a key source of nitrogen fertilizer. Surging natural gas prices have boosted the price of nitrogenous fertilizer by 90 percent since 1998 (Figure 2-3). During last December and January, several nitrogen production plants shut down, and capacity utilization fell to 50 percent. Anhydrous ammonia recently sold for \$330 a ton in the Midwest, compared to \$210 a ton for

all of 2000 and \$160 to \$170 a ton at the start of 2000.

Depending on the region of the country and type of farming enterprises, energy-related expenses range from 10 to 30 percent of operating costs for producing major crops. Farm operating costs are highest where fertilizer use is heaviest and natural gas is used for irrigation pumps, such as wheat, cotton, and corn farms in the West and southwestern plains states. Costs are high for greenhouse and nursery crops that use natural gas for heating. Perishable crops also face problems, as energy costs in processing are markedly higher.

Most of California's 9.5 million irrigated acres use electricity to pump water. In addition to higher bills, California farmers will likely face rolling blackouts this summer, which may disrupt farming and processing operations. Low stream flows in the West this year may lead to more pumping of ground water, which will add to irrigation costs in the West. As a result, the costs of California's agricultural products may rise significantly.

In 2001, farmers' total cash production expenses are forecast to increase by an additional \$1.5 billion to a record \$179.5 billion.

Farm production costs are rising sharply, while farmers' incomes remain low. Depending on the region of the country and type of farming enterprises, energy-related expenses range from 10 to 30 percent of operating costs for producing major crops



Even though total planted acreage is expected to fall this year, higher natural gas prices will raise expenses for nitrogen fertilizer. At the same time, net cash farm income is projected to decline from \$56.4 billion in 2000 to under \$51 billion in 2001, as production expenses continue to rise.

Taken together, fertilizer, fuel, and electricity costs for farmers are forecast to reach \$24 billion for 2001, up by about 28 percent from \$18.7 billion in 1999. This increase is about 9 percent of U.S. net cash farm income, and that share could be much higher for many individual commodities.

Transportation

The transportation sector accounts for nearly 30 percent of total U.S. energy consumption. The major transportation fuel sources are petroleum-based gasoline and diesel, jet, and marine-mode bunker fuels. Natural gas pipelines are used for product distribution, and electricity is the primary source of power for rail transit and liquid pipeline transmission and distribution.

During 2000, oil prices surged to a nine-year high, and gasoline prices skyrocketed. On average, fuel prices rose by 30 to 40 cents a gallon from 1999 prices, resulting in sharp increases for most modes of trans-



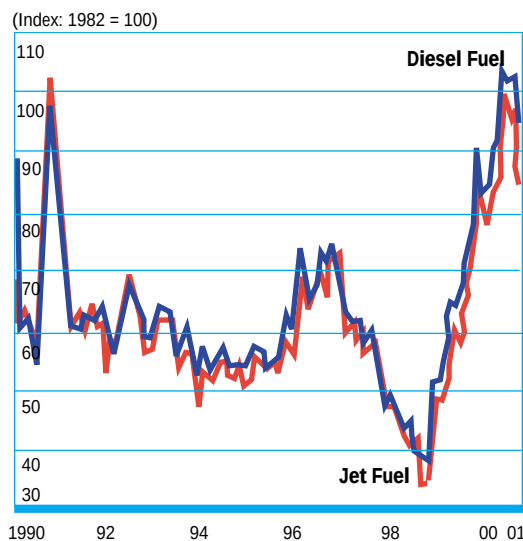
A recent study by a San Francisco Bay business group concluded that blackouts could cost California as much as \$16 billion annually, and \$5 billion in the Bay area alone.

portation, with nearly a 60 percent increase in railroad diesel fuel prices.

Price spikes have hit the travel and trucking industries particularly hard and have led to the closure of some operations. Trucking bankruptcies are currently at an all-time high. Over 3,500 motor carrier operations failed in 2000, a dramatic increase over the previous record high of 2,700 motor carrier failures in 1997. Producer prices for intermediate diesel fuel and aviation fuel each rose by about 140 percent from a low in December 1998, affecting passenger and freight transport in the highway, airline, rail, and other transportation sectors (Figure 2-4).

For most transport operations, energy-related expenses were 7 to 14 percent of total operating costs in 1998–99. This share was expected to jump to 10 to 25 percent in 2000. Excluding private auto travel, U.S. passenger and freight operations in 1999 generated about \$600 billion in annual revenue and paid approximately \$60 billion for fuel and power. If the volume stayed the same in 2000, the various increases in fuel costs for each mode of transportation would yield a fuel bill of

Figure 2-4
Transportation Costs Are on the Rise



The recent 140 percent rise in producer prices for intermediate diesel and airline fuels has affected the price of passenger and freight transport.

Note: Plotted through February 2001.
Source: U.S. Department of Labor.

about \$80 billion—an increase of one-third over the prior year's bill.

Economic Impacts of California's Energy Crunch

In California, 43 percent of small businesses surveyed in February, 2001, said the power problem had dimmed their views about California as an attractive place for doing business. When asked whether they agreed with the statement, "The electricity problem has forced me to take concrete steps exploring the possibility of moving my business out of California," 18.3 percent of small business respondents said they either agreed or strongly agreed with the statement. More than 31 percent said they will probably or definitely cut back on planned business investment, and almost 20 percent are exploring a move to another state. Half of these small businesses concluded that blackouts would reduce their earnings.

The Silicon Valley Manufacturing Group recently estimated that its nearly 200 members lost over \$100 million dollars because of one day of rolling blackouts in June 2000. Countless more millions of dollars have been lost by interruptible commercial power users. Fontana-based California Steel Industries estimates it lost \$2.4 million in a single day after its interruptible power was cut off twice for a total of about 12 hours. A recent study by a San Francisco Bay business group concluded that blackouts could cost California as much as \$16 billion annually, and \$5 billion in the Bay area alone.

The example of California's utilities illustrates the potentially severe negative effects on companies whose business is highly sensitive to energy prices. In this instance, rising energy costs coupled with an inability to pass those costs along to customers has created a sharp increase in short-term liabilities. Pacific Gas & Electric has been forced to file for bankruptcy as a result, and Southern California Edison, while avoiding bankruptcy for the time being, has seen its access to credit markets disappear and the value of its financial assets plummet. Resulting concerns about solvency have led to a withdrawal of bank-

lending facilities and supplier credit.

The situation in California is of particular concern because of the major role the state plays in the regional and national economies. California's economy is equivalent to about 13 percent of U.S. gross domestic product (GDP), and it has accounted for an even larger share of U.S. GDP growth in recent years. Some businesses and consumers have been affected by production losses, lost wages, and higher energy bills resulting from rolling blackouts and higher natural gas prices.

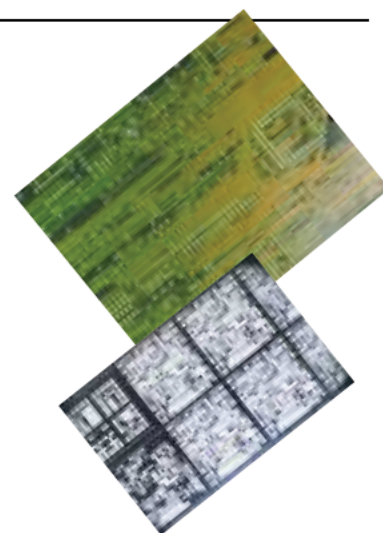
The power supply crunch in California and the West could affect the region's economy, as energy supply uncertainty could reduce investment in the region. California's troubles could also spill over to the national economy:

- California accounted for 11 percent of U.S. manufacturing output in 1998. Sectors in other regions that rely on those products, or that supply inputs to California manufacturers, may share any pain caused by the energy squeeze.
- Disruptions to California's economy could have negative impacts on our international trade. California accounts for over 16 percent of total U.S. commodity exports; nearly 25 percent of industrial equipment and computers, electronics, and instruments exports; and over 15 percent of farm commodity and food product exports.
- The credit problems of the California utilities have boosted commercial paper rates for all lower-rated borrowers, and liquidity in the commercial paper market has fallen. This will push some firms to seek other sources of financing, which can be more costly than commercial paper.

American consumers and businesses are best served when markets function freely. Free markets allow prices to reflect changes in demand and supply, and avoid subsidies, price caps, and other constraints.

Improvements in Energy Efficiency Can Help

Improved energy efficiency strengthens energy security. The 42 percent decline in the intensity of U.S. energy use since the energy crisis in 1973 reflects a combination of technological advances, conservation ef-

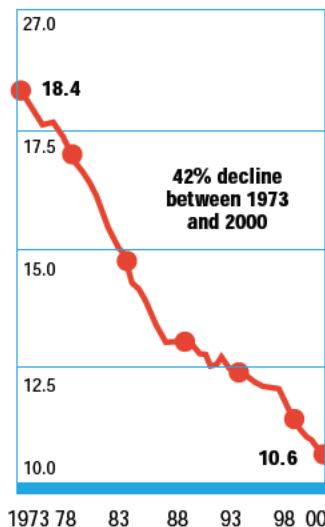


The Silicon Valley Manufacturing Group recently estimated that its nearly 200 members lost over \$100 million dollars because of only one day of rolling blackouts in California.

Figure 2-5

Conservation Through Higher Efficiency Energy Consumption per Dollar of Real GDP

(Thousands of Btus)



Energy intensity is the amount of energy used to produce a dollar's worth of gross domestic product (GDP). As a result of the 42 percent decline in energy intensity since the first energy crisis in 1973, the U.S. economy is far better prepared to day than it was in the 1970s to adjust to energy price or supply shocks.

Note: Real GDP in 1996 chained dollars. Source: U.S. Department of Energy, Energy Information Administration.

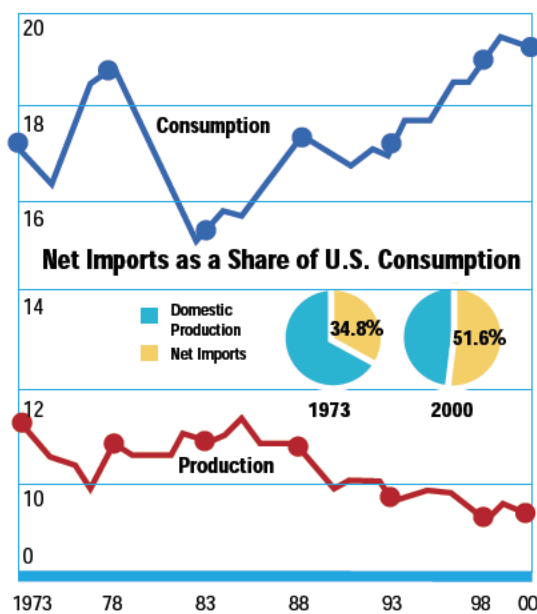
forts, regulatory action, market response, and a shift toward a service economy (Figure 2-5). Our improvements in energy efficiency have prevented our current energy problems from becoming worse.

The macroeconomic effects of a substantial rise in energy prices take two forms. First, to the extent that energy resources are imported, more U.S. dollars must be sent abroad to finance energy consumption, thus reducing funds available for investing in our own country. Second, higher prices cause dislocations among certain sectors of the economy, which could ultimately feed through to lower GDP growth and higher inflation.

Reliance on Foreign Energy

Between 1973 and 2000, U.S. dependence on foreign oil rose from about 35 percent to more than 52 percent of U.S. consumption (Figure 2-6). During the same period, the import share of natural gas consumption climbed from less than 5 percent to more than 15 percent and continues to rise.

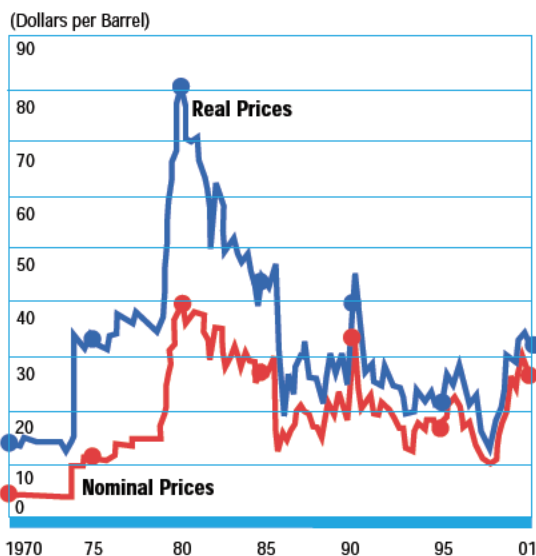
Figure 2-6
Dependence on Oil Imports Is Rising
(Millions of Barrels per Day)



Over the past few decades, U.S. consumption of oil and petroleum products has increasingly outpaced domestic production. Today the United States imports over half of the oil it consumes—up from about 35 percent in the early 1970s.

Note: Petroleum includes both crude oil and petroleum products.
Source: U.S. Department of Energy, Energy Information Administration.

Figure 2-7
Oil Prices Have Risen Sharply
Monthly Spot Price of West Texas Intermediate Crude Oil



Despite the sharp rise in crude oil prices since late 1998, real prices still remain lower than at any time from 1974 to 1985.

Note: Real prices in 2000 dollars. Prices deflated using the Consumer-Price Index—Urban (CPI-U) Research Series for all items linked to CPI-U-X1 prior to December 1977.

Sources: Wall Street Journal; U.S. Department of Labor, Bureau of Labor Statistics.

Imports of energy products make up nearly 11 percent of all U.S. imports. By contrast, U.S. energy exports are relatively small. The energy trade deficit relative to our GDP represents the share of U.S. income that must be exported to purchase foreign fuel to meet domestic energy needs. The U.S. energy trade deficit in 2000 was about \$120 billion, most of which was spent on oil imports.

As a share of GDP, the energy trade deficit had fallen to as low as 0.4 percent at the beginning of 1999, when prices for imported crude oil were less than \$10 a barrel. However, by the end of 2000, these prices had tripled to more than \$30 a barrel (Figure 2-7). As a result of both the oil price spike and growing U.S. demand, the energy deficit deteriorated significantly to 1.3 percent of GDP by the fourth quarter of last year—the largest deficit relative to GDP since the mid-1980s (Figure 2-8). The rise in oil prices alone has added about 0.7 percent of GDP to the U.S. trade deficit, compared to 0.9 percent in the euro currency area, and 0.8 percent in Japan.



Figure 2-8
The U.S. Energy Trade Deficit Has Worsened
 (Percent)



The energy trade deficit relative to GDP represents the share of domestic income that must be exported to support domestic energy needs. For the past several years, the United States has been a net importer of energy products. As a consequence, our energy trade balance has been in deficit. By the fourth quarter of 2000, the energy deficit had deteriorated significantly to 1.3 percent of GDP—the largest since the mid-1980s.

Note: Plotted quarterly through the fourth quarter of 2000.
 Source: U.S. Department of Commerce, Bureau of Economic Analysis.

Net U.S. oil imports are 4 billion barrels a year, which means that each \$1 increase in the price of imported crude oil boosts U.S. expenditures by about \$4 billion. Given these guidelines, the \$20 per barrel increase from early 1999 to late 2000 translates into an export of roughly \$80 billion a year (0.9 percent of GDP) when measured from the low price prevailing at the end of 1998.

Impacts of Energy Prices on Financial Markets

An analysis of the financial impacts of higher energy prices can be divided into two parts: the effects on individual firms whose securities comprise the financial markets, and the macroeconomic impact on inflation and interest rates. Rising energy costs and greater volatility in energy prices can have a negative effect on both individual firms and the broader financial environment, generally producing lower asset prices and higher interest rates. The financial market impact to date of rising energy prices has been limited to firms with high sensitivity to energy costs and to those with significant exposure to the California crisis. The second broad effect of rising energy costs is an increase both in measured inflation

Financial markets react to energy costs and the effect those energy costs have on both individual firms and sectors of the market.

and in expectations for future inflation. Both factors have considerable impact on interest rates and, therefore, on the borrowing costs for businesses and consumers throughout the economy.

Inflation Expectations and Interest Rates

Measurable inflation, for both producers and consumers, is a primary concern of the Federal Reserve in conducting monetary policy. Energy costs represent roughly 16 percent of the producer price index for finished goods and 8 percent of the consumer price index. This means that sharply rising energy costs can have a substantial impact on the Federal Reserve's decision-making process. Additional impacts will come from the market's anticipating Federal Reserve actions and pushing short-term interest rates higher than they otherwise would have been. Higher short-term interest rates raise the nominal cost of borrowing for firms and individuals and can slow economic growth.

Rising energy prices can also raise the inflation expectations of lenders, which can result in higher interest rates for borrowing at longer maturities. Rising long-term interest rates can reduce long-term investment, limiting future economic growth and productivity gains. Such an outcome would carry negative consequences for growth-sensitive financial sectors, such as equity and high-yield debt markets.

More broadly, declining credit fundamentals for certain business sectors could raise borrowing costs for firms not directly affected by higher energy prices. For example, commercial paper rates for all lower-rated borrowers have been affected by the credit problems of the California utilities, and liquidity in the market has fallen. As a result, firms may need to seek other sources of financing, such as bank loans (if obtainable) or asset-backed loans, that can be more costly than traditional commercial paper issuance.

Global Financial Markets

The upward pressure on interest rates that may result from higher U.S. energy costs also affects markets beyond our borders. U.S. monetary policy and related movements in short-term interest rates can have a significant impact on other countries. While the effect varies from region to region, many emerging mar-

ket economies, particularly in Latin America, are vulnerable to upward moves in U.S. interest rates.

Higher nominal interest rates in the developed countries tend to reduce the amount of capital flowing to emerging markets. To the extent that this reduces investment, economic activity may be further reduced. In addition, borrowing in dollars is a significant source of funding for sovereign and private-sector entities worldwide, particularly in the emerging markets. Rising U.S. interest rates will increase the interest expenses for these borrowers, diverting funds from more productive uses and reducing overall credit quality.

The global market for energy is highly fragmented and region-specific, with the exception of oil. Nevertheless, certain nations and regions are net importers of energy and are highly sensitive to changing prices. Japan, a major importer of oil and natural gas, is particularly vulnerable. Europe is a net importer of energy, with certain exceptions, while emerging market nations vary widely in their dependence on foreign energy sources.

At the macroeconomic level, rising energy prices will increase the current account deficit of energy-importing nations. Since current account deficits must be financed, these nations will most likely need to pay higher interest rates to attract the necessary capital. As noted, this will tend to reduce domestic investment and lower long-term growth. In some countries, such as the United States or Japan, changes in interest rates and growth expectations can have substantial global impact.

Central banks and monetary authorities vary in the degree to which they focus on inflation in setting monetary policy, making some countries more or less likely than others to raise interest rates in an environment of rising energy prices.

Although Japan maintains a current account surplus due to manufacturing exports, its role as an international creditor could diminish. This may have additional impacts on the global financial markets, since Japanese financial institutions are generally suppliers of global credit.

The impact of rising energy costs on the dollar is likely to be mixed. While slower U.S. growth generally reduces demand for dollars, rising oil prices are likely to increase demand, since oil contracts are usually denominated in dollars.

Summary of Recommendations

★ The NEPD Group recommends that the President direct the Secretary of Energy to explore potential opportunities to develop educational programs related to energy development and use. This should include possible legislation to create public education awareness programs about energy. Such programs should be long-term in nature, should be funded and managed by the respective energy industries, and should include information on energy's compatibility with a clean environment.

★ The NEPD Group recommends that the President take steps to mitigate impacts of high energy costs on low-income consumers. These steps would include:

- Strengthening the Low Income Home Energy Assistance Program by making \$1.7 billion available annually. This is an increase of \$300 million over the regular FY 2001 appropriation.
- Directing the Secretaries of Interior and Health and Human Services to propose legislation to bolster LIHEAP funding by using a portion of oil and gas royalty payments.
- Redirecting royalties above a set trigger price to LIHEAP, whenever crude oil and natural gas prices exceed that trigger price, as determined by the responsible agencies.

★ The NEPD Group recommends that the President increase funding for the Weatherization Assistance Program by \$1.2 billion over ten years. This will roughly double the spending during that period on weatherization. Consistent with that commitment, the FY 2002 Budget includes a \$120 million increase over 2001. The Department of Energy will have the option of using a portion of those funds to test improved implementation approaches for the weatherization program.

★ The NEPD Group recommends that the President support legislation to allow funds dedicated for the Weatherization and State Energy Programs to be transferred to LIHEAP if the Department of Energy deems it appropriate.

★ The NEPD Group recommends the President recognize unique regional energy concerns by working with the National Governors Association and regional governor associations to determine how to better serve the needs of diverse areas of the country.

★ The NEPD Group recommends the President direct FEMA to prepare for potential energy emergencies.

- -FEMA should work with states' Offices of Emergency Management as they expand existing emergency operations plans to identify potential problems and address consequences of the power shortages. FEMA should use its current Regional Incident Reporting System to identify any situations that might demand immediate attention.
- Using the structure of the already existing Federal Response Plan, FEMA should conduct Regional Interagency Steering Committee (RISC) meetings for states affected by the energy shortfalls. The RISC is a FEMA-led interagency committee comprised of agencies and departments that support the Federal Response Plan. Either an upcoming, scheduled RISC meeting or a special-focus RISC meeting can be held to identify the short-term energy outlook, as well as any expected consequences, in each of the states during the peak summer season.

Protecting America's Environment

Sustaining the Nation's Health and Environment

Over the last three decades, American ingenuity has led to a reduction in adverse environmental and public health impacts from energy development and use. Americans demand a reliable energy supply and a clean environment, and we can achieve both. Spurred by strong environmental concerns, competitive forces, and environmental regulations, businesses have developed innovative technologies and pollution-prevention techniques to protect the environment. However, more can be done.

As our energy needs continue to grow and our production and distribution system is strained to capacity, it is clear that the lack of a comprehensive energy policy has environmental costs. For example, to prevent blackouts, California officials must tolerate a large short-term increase in smog-forming nitrogen oxides emissions. In Los Angeles, older, dirtier power plants have had to run longer than expected. California is also rushing to use mid-sized “peaker power plants” and diesel-fired emergency backup generators to keep the lights on.

The short-term cost in increased pollutant emissions of these emergency measures has been stark. Preliminary figures from California's South Coast Air Quality Management District indicate emissions have doubled in the first three months of the year compared with last year. In addition to nitrogen oxides emissions, diesel-fired backup generators also emit toxic soot. But with many days of blackouts predicted in California this summer, these generators will most likely run for much longer than expected, and could greatly increase emissions.

In the longer term, penalties and technological improvements should offset the impact of these increased emissions. However, California's experience demonstrates the environmental costs of not building an adequate supply of clean energy.

Government's Role

The federal government has a unique role in facilitating energy development while simultaneously protecting the environment and conserving our country's natural resource legacy. Energy development initiatives will be successful only if they adequately address their impacts on natural resource values.

Federal, state, tribal, and local governments have the responsibility of protecting unique natural resources and environmental values. In fact, some environmental protections we enjoy today are often taken for granted. For example, lead levels in ambient air today are 98 percent lower than they were in 1970, largely because government regulations required that lead be removed from gasoline. The reduced number of children with IQs below 70 is attributed to reducing lead in our environment.

As U.S. energy needs grow, additional innovations will be necessary to continue improving environmental conditions and to meet new environmental challenges. As we improve the energy production and distribution system, all levels of government must ensure that regulatory systems protecting public health and the environment are rigorous and efficient, and encourage innovation and improvement.



Roughly 30 percent of our nation's electricity supply is now generated by nuclear, hydropower, and renewable sources, all of which have few air emissions.

Air Quality Regulatory Programs

Advances in technology and environmental regulations have decreased aggregate emissions of key air pollutants over the last three decades, despite a marked increase in energy consumption (Figure 3-1). Roughly 30 percent of our nation's electricity supply is now generated by nuclear, hydropower, and renewable sources, all of which have few air emissions.

Nonetheless, fossil fuel-fired power plants, other industrial sources, and vehicles remain significant sources of air pollution (Figure 3-2). These emissions can be associated with significant health problems, including respiratory and cardiopulmonary disease, cancer, and birth defects. In addition, they can be harmful to forests, water bodies, and fish, and can decrease visibility in scenic areas.

Environmental Protection Agency's (EPA) Acid Rain Program, enacted as part of the 1990 Clean Air Act Amendments, is the only program directed primarily at reducing air emissions from electric utilities.

Using flexible market-based incentives instead of technology-forcing standards, the program has reduced sulfur dioxide (SO₂) emissions from utilities faster than required by law for a fraction of the initial cost estimates. By 2010, EPA expects the program will reduce annual SO₂ emissions by 10 million tons from 1980 levels, thus avoiding significant health problems and the costs associated with those levels.

Federal and state regulatory programs also limit air pollution directly by restricting emissions from cars and trucks, and indirectly by setting criteria for the fuel for these vehicles. An individual car meeting 2004 federal requirements will emit 95 percent less carbon monoxide (CO), 94 percent fewer nitrogen oxides (NO_x), and 98 percent fewer hydrocarbons than an average car did before laws limiting such vehicle pollution. Although individual cars and trucks are far cleaner today than they were in 1970, total emissions from the fleet of highway vehicles have remained relatively constant, because Americans drive twice as many miles today (2.5 trillion miles a year) as they did in 1970

(1.1 trillion miles a year).

Despite these and other achievements, further air quality improvements can be sought, as well as ways to address new problems identified by recent scientific findings. EPA has recently adopted new, more stringent standards to further reduce ozone and particulate matter. To meet public health and environmental challenges, power plants, industrial sources, and vehicles will need to produce fewer potentially harmful emissions.

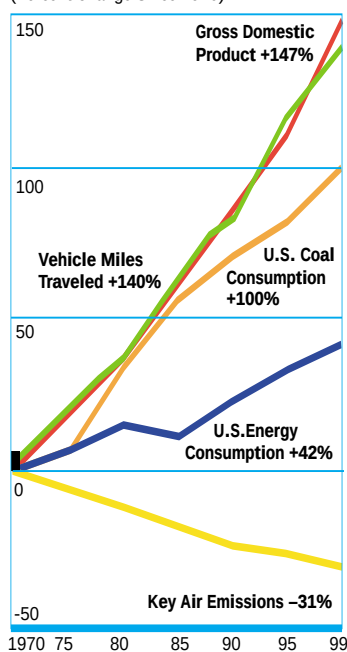
Recommendation:

★ The NEPD Group recommends that the President direct the Administrator of the Environmental Protection Agency (EPA) to propose multi-pollutant legislation. The NEPD Group recommends that the President direct the EPA Administrator to work with Congress to propose legislation that would establish a flexible, market-based program to significantly reduce and cap emissions of sulfur dioxide, nitrogen oxides, and mercury from electric power generators. Such a program (with appropriate measures to address local concerns) would provide significant public health benefits even as we increase electricity supplies.

- Establish mandatory reduction targets for emissions of three main pollutants: sulfur dioxide, nitrogen oxides, and mercury.
- Phase in reductions over a reasonable period of time, similar to the successful acid rain reduction program established by the 1990 amendments to the Clean Air Act.
- Provide regulatory certainty to allow utilities to make modifications to their plants without fear of new litigation.
- Provide market-based incentives, such as emissions-trading credits to help achieve the required reductions.

Figure 3-1
Cleaner Air: Energy Consumption Has Risen While Emissions Have Declined

(Percent Change Since 1970)



Despite a marked increase in U.S. energy consumption, a combination of environmental regulations and technologies has decreased aggregate emissions of key air emissions: SO₂, NO_x, mercury, CO, and volatile organic compounds.

Sources: U.S. Department of Energy, Energy Information Administration, and U.S. Environmental Protection Agency.

Cleaner, More Efficient Technologies

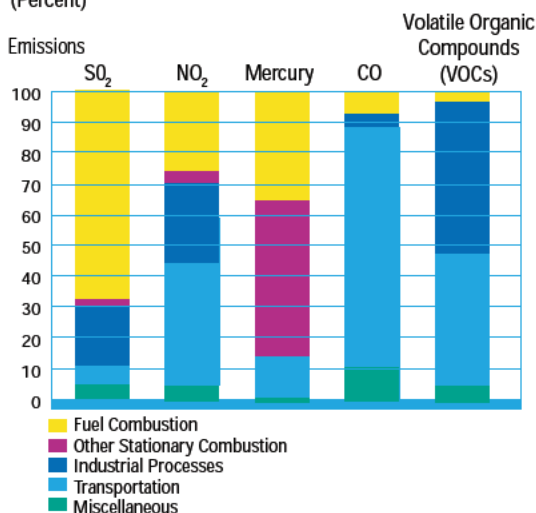
Emission control technologies and emission prevention not only decrease pollution but can also contribute to economic prosperity. Innovative emission control and prevention technology and increasingly efficient energy systems have developed at a brisk pace, increasing our ability to provide cleaner, cheaper energy. Besides reducing pollution, environmental technologies account for about \$21.3 billion in U.S. exports, and support approximately 136,000 U.S. jobs.

The need to reduce emissions from cars and trucks has contributed to technological innovations that have transformed the domestic and global automotive industries. U.S. vehicle emission standards were the primary driving force for the original development of innovative technologies, many of which have become standard design features of today's high-tech vehicles: sophisticated three-way catalysts, on-board computers, oxygen sensors, and fuel-injection systems for cars and advanced fuel systems for trucks. Technologies such as these have allowed today's vehicles to be much cleaner, more efficient, higher performing, more reliable, and more durable than their counterparts of the 1960s and 1970s. Manufacturers are now working on developing state-of-the-art pollution control technology to further reduce emissions from motor vehicles. For optimal performance, this technology requires low-sulfur fuel that, consistent with applicable law, will be required in 2004 for gasoline and 2006 for diesel fuel. Some vehicles use alternative fuels (*e.g.*, natural gas, propane, ethanol, and electricity); others operate with a hybrid gasoline and electrical motor; and others are using fuel cells.

Cleaner Electricity

The source of energy used for power generation significantly affects the amount of air emissions. Clean energy can be generated from nuclear plants, hydropower facilities, wind farms, and solar energy systems with negligible (if any) air emissions. These sources today make up about 30 percent of our electricity supply. Solar and

Figure 3-2
Sources of Pollutants from Energy Generation and Use
(Percent)



wind energy systems will continue to improve with advances in short-term weather and climate forecasting. Improved forecasting can also maximize hydropower efficiency.

Technology significantly reduces pollution from coal-fired power plants, which generate more electricity in the United States than any other source. For example, scrubbers can remove 95 percent of the SO₂ emissions from a coal-fired power plant. With the innovative, market-based SO₂ reduction requirements of the Clean Air Act Amendments of 1990, the estimated cost of using a scrubber on a coal-fired power plant to remove one ton of SO₂ has dropped approximately 40 percent in four years, from \$474/ton in a 1993 estimate to \$282/ton in a 1997 estimate, and continues to decline. Other existing control technologies for coal-fired plants can reduce NO_x emissions by more than 90 percent.

A recently permitted state-of-the-art coal-fired unit, for example, at a Kansas City Power & Light facility, has 88 percent lower NO_x, 99 percent lower particulate matter, and 92 percent lower SO₂ emissions than would an uncontrolled facility.

Recent research by the Department of Energy (DOE), EPA, and private companies suggests that existing technologies can also significantly reduce mercury emissions.

Technologies for Reducing SO₂ Emissions

Many power plants use flue-gas desulfurization, or scrubbers, to reduce SO₂ emissions from burning coal. The most common wet scrubber, the limestone forced-oxidation (LSFO) process, removes SO₂ from the flue gas by sorption and through chemical reactions with the limestone. LSFO technologies can remove up to 98 percent of SO₂ and significant amounts of mercury. The most common dry scrubber, the lime spray-drying process, is used for plants that burn lower-sulfur coals. A lime slurry mixes with the hot flue gas in a spray dryer and reacts with SO₂. By recapturing sorbent at the bottom of the spray dryer removed in a particulate control device, dry scrubbers can remove up to 96 percent of SO₂.

Clean Coal Technologies

New clean coal technologies are showing that air pollution can be reduced, and energy efficiency increased, by using America's abundant supply of coal.

Most conventional air emission control technologies installed on coal-fired electric-generating boilers have been designed to remove a specific pollutant from the stack flue gas. Because these technologies may not be the most cost effective means of reducing multiple pollutants, several companies are developing a single-control technology to reduce multiple air pollutants to levels equivalent to those achieved by conventional controls.

For example, a First Energy plant in New Hampshire recently pilot-tested state-of-the-art technology that has cut NO_x emissions by 76 percent, SO₂ by 44 percent, total particulate matter by 99.94 percent, and mercury by 81 percent. The process uses electrically charged particles instead of catalysts to oxidize the air pollutants into products that are easily removed and can be converted to gypsum, fertilizer, and concentrated acids. American Electric Power is installing a wet scrubber system that it expects will remove up to 75 percent NO_x and

90 percent mercury. It injects a phosphorus mixture into the hot flue gas, causing the release of ozone. The ozone then oxidizes the mercury into ionic mercury and the NO_x into N₂, both of which are water-soluble and easily removed.

Technologies for Improved Efficiencies

Two-thirds of the energy used in a conventional coal-fired power plant is wasted in the production of electricity. These losses can be minimized through a number of innovations, including installing high efficiency steam turbines, reducing steam leaks, and using software to optimize combustion efficiency. New coal-burning power plants can achieve efficiencies of over 40 percent using existing technology, and companies are developing even more efficient technologies. Wasted energy can also be recycled for use in industrial processes or for heating buildings.

A family of technologies known as combined heat and power (CHP) can achieve efficiencies of 80 percent or more. In addition to environmental benefits, CHP projects offer efficiency and cost savings in a variety of settings, including industrial boilers, energy systems, and small, building-scale applications. At industrial facilities alone, there is potential for an additional 124,000 megawatts (MW) of efficient power from gas-fired CHP, which could result in annual emission reductions of 614,000 tons of NO_x emissions and 44 million metric tons of carbon equivalent. CHP is also one of a group of clean, highly reliable distributed energy technologies that reduce the amount of electricity lost in transmission while eliminating the need to construct expensive power lines to transmit power from large central power plants.

The U.S. Department of Energy, through its Clean Coal Technology Program, is working with utilities and scientists to develop even cleaner, more efficient electricity-generating systems using coal. One of the most promising new approaches to using coal for clean production of electricity is integrated gasification combined-cycle (IGCC) technology. IGCC power plants convert coal to a gaseous fuel, from which most

Using flexible market-based incentives, EPA's Acid Rain Program has reduced sulfur dioxide (SO₂) emissions from utilities faster than required by law for a fraction of the initial cost estimates.



Clean Coal Technologies Up Close

The Wabash River Coal Gasification Project in Terre Haute, Indiana, is one of the cleanest, most efficient coal-burning facilities in the country. Partly funded by the Department of Energy (DOE) as part of its Clean Coal Technology Program, the 262-MW coal gasification facility is owned and operated by PSI Energy and Global Energy, Inc. Instead of being directly burned, the coal is gasified and then combusted in a combined-cycle gas turbine. This allows the coal to burn more efficiently—which means it gets more energy than a traditional plant out of the same amount of coal. The Wabash River Facility is over 20 percent more efficient than a typical coal-fired power plant.

The gasification process also allows many of the impurities in the coal to be removed before it is combusted to generate electricity. At the Wabash River project, over 99 percent of the sulfur is removed from the coal and marketed to industrial users of sulfur. Slag is also removed and is marketed to the construction industry. The plant's design allows it to burn other fuels, such as petroleum coke.

DOE is currently working with Global Energy and other industry partners to see if the plant could also be used to co-produce chemical feedstocks and transportation fuels. Additionally, DOE and its partners are studying lessons learned from the project to design a less expensive, more efficient coal gasification facility that would be ready for commercial deployment by 2005.

of the impurities are removed prior to combustion, and then use the gaseous fuel in a combustion turbine to produce electricity. Waste heat from the turbine is used to generate steam and drive a steam turbine, to produce more electricity.

Coal gasification plants offer the flexibility to burn other fuels, such as petroleum coke, and to make other products in addition to electricity, such as chemical feedstocks and transportation fuels. Hydrogen, which is produced directly in the coal gasifier, can be used in fuel cell-equipped vehicles. Methane, hydrogen, and other gasified coal products can be recombined into more traditional fuels, such as methanol, gasoline, or diesel fuel. Because these fuels would contain essentially no sulfur, they would easily meet EPA's sulfur standards for transportation fuels, and they would be usable in fuel cell-equipped vehicles designed for these fuels.

Two plants demonstrating coal gasification technology have already been built in the United States and have achieved over 98 percent SO₂ reduction, 90 percent NO_x reduction, particulate emissions below detectable levels, and approximately 38 percent efficiency. EPA believes that lessons

learned will enable the next plant of this design to achieve 42 percent efficiency, and the research goal is to achieve 60 percent efficiency for plants introduced after 2015.

A modern gas-fired power plant has virtually no SO₂ or mercury emissions and emits 97 percent less NO_x and 50 percent less carbon dioxide (CO₂) than a traditional coal-fired plant. Natural gas as a source of electricity generation is on the rise, in part because it can help generators meet increasingly stringent clean air requirements.

Conservation and Environmental Protection

Conserving energy minimizes adverse environmental effects. Government partnerships with businesses and consumers are improving the energy efficiency of homes, office buildings, transportation sources, and industrial sites throughout the country. EPA's voluntary conservation and energy efficiency programs include Energy Star products labeling; Energy Star Residential programs for both new homes and home improvement; Energy Star Buildings, principally for commercial buildings; and new Energy Star for Industry, which focuses on manufacturers. In 2000, business participation in EPA's voluntary energy efficiency

programs reduced NOx emissions by more than 160,000 tons.

Through EPA's and the Department of Transportation's Commuter Choice Leadership Initiative, private-public employers are offering employees a variety of commuting options, which encourage commuting patterns that save fuel and energy while reducing emissions. For example, a 10 percent reduction in the rate of growth in vehicle miles traveled can result in annual savings of 38 million barrels of gasoline (82 million barrels of oil) by 2005, and can remove 45,000 metric tons of NOx, 37,000 metric tons of hydrocarbons, and 4.8 million metric tons of carbon-equivalent emissions.

Energy efficiency and conservation in the home are also important factors. Examples include EPA's home improvement program, which involves efficient appliances, duct work to prevent air conditioners from leaking, efficient windows, programmable thermostats, and efficient residential lighting.

Federal and state regulators are working with businesses and communities to mitigate adverse environmental impacts by requiring developers and operators to choose more environmentally friendly sites, infrastructure routes, and operational criteria; fostering the use of technologies that both protect the environment and still meet energy production goals; and requiring reclamation and mitigation of any environmental damage.

Water Quality

Oil, gas, and coal extraction processes can degrade water quality through their discharges. Energy generation and use can also degrade water quality by directly discharging pollutants into water bodies; changing the temperature, timing, and flow characteristics of water bodies; and emitting pollutants into the air that are ultimately deposited in water. Leaking storage tanks and pipelines release petroleum and fuel additives that can contaminate surface water and ground water, including drinking-water supplies.

Federal and state regulators are working with businesses and communities to mitigate these adverse impacts by requiring developers and operators to choose more environmentally friendly sites, infrastructure routes, and operational criteria; fostering the use of technologies that both protect the environment and meet energy production goals; and requiring reclamation and mitigation of any environmental damage. For example, as a result of an analysis under the National Environmental Policy Act of the impacts of a new power plant in California, the company building the plant agreed to change the design to use a dry cooling method. This change reduced ground-water consumption by 95 percent and eliminated both cooling tower "blowdown" water and particulate emissions, while still achieving the desired energy production. Adverse impacts to aquatic life from cooling-water intakes, thermal discharges, and hydropower intakes can be minimized with proper design and environmental controls. A cooperative government, industry, and community-based approach during project siting and design will help ensure full consideration of the effects upon fish and aquatic resources.

Programs to reduce air pollution also help clean up water bodies. For example, reducing electric utilities' air emissions of NOx and SO₂ and vehicles' NOx emissions reduces eutrophication and acid deposition in estuaries, both of which can harm fish populations and threaten commercial and recreational yields. For example, roughly 25 percent of nitrogen (which contributes to



eutrophication) entering Chesapeake Bay is from air emissions. And by significantly reducing SO₂ air emissions, the Acid Rain Program has helped reduce the acidification of water bodies.

Airborne mercury emitted by coal-fired power plants has been deposited into thousands of water bodies, and humans can be exposed to toxic methyl mercury when they eat fish from these waters. The Bush Administration will propose legislation adding mercury to the list of pollutant emissions from power plants that will be subject to mandatory limits.

Fish, Wildlife, and Their Habitat

Ecosystems provide food, shelter, and critical breeding and spawning grounds for fish and wildlife, and support commercial and recreational fishing, tourism, and other activities that contribute billions of dollars to the U.S. economy every year. Oil and gas exploration and production, hydropower dams, power plants, pipelines, and other energy-related projects can potentially affect fish, wildlife, and habitat. However, technological advances, a strong commitment to environmental protection, and the use of appropriate regulatory tools can enable proper energy development to go forward in an environmentally sensitive manner. It is important to recognize and to continue the progress in this area.

When energy development is proposed, the federal government has the dual

Recommendation:

★ The NEPD Group recommends that the President direct the Secretary of the Interior to work with Congress to create the “Royalties Conservation Fund.”

- This fund will earmark potentially billions of dollars in royalties from new oil and gas production in ANWR to fund land conservation efforts.
- This fund will also be used to eliminate the maintenance and improvements backlog on federal lands.



responsibilities of facilitating such energy development and conserving our natural resource legacy.

Special efforts are often necessary to ensure that proposed energy projects do not diminish the vitality of these unique resources. Working together, the public, businesses, and federal, state, tribal, and local governments can ensure that environmental impacts are carefully evaluated when considering energy exploration and production activities. For example, such precautions have been important for the exploration and production that is already allowed today in 42 National Wildlife Refuges.

Hydropower Generation

Hydropower, although a clean energy source, does present environmental challenges. Unless properly designed and operated, hydropower dams can injure or kill fish, such as salmon, by blocking their passage to upstream spawning pools. Innovations in fish ladders, screens, and hatcheries are helping to mitigate these adverse impacts. Ongoing dam relicensing efforts are resulting in community involvement and the industry's application of the latest technologies to ensure the maintenance of downstream flows and the upstream passage of fish. These efforts also have been successful in identifying and removing older, nonfunctioning dams and other impediments to fish movements.

Technological advances and a strong commitment to environmental protection are enabling the healthy coexistence of our nation's diverse ecosystems with the development of energy resources.



Ecosystems provide food, shelter, and critical breeding and spawning grounds for fish and wildlife, and support commercial and recreational fishing, tourism, enhance our quality of life, and other activities that contribute billions of dollars to the U.S. economy every year.



Some natural resource areas are to be protected from any exploration. In other areas, energy development can proceed using the most advanced designs and technologies to ensure that proposed energy projects do not diminish the vitality and diversity of these unique resources.

An example of such successful collaboration involves the Wanapum Dam on the Columbia River. In coordination with the National Marine Fisheries Service, the Grant County Public Utility District No. 2 installed spillway deflectors that effectively reduced concentrations of total dissolved gas that can harm fish and other aquatic life. Furthermore, through the unique collaboration on this project, the cost for the spillway deflectors was a fraction of that for deflectors installed at other hydropower projects.

Coal, Oil, and Gas Exploration and Production

Certain exploration and production activities can pose environmental impacts to wildlife habitat, unless conducted in a way that protects the environment. In sensitive areas, these effects can often be avoided or minimized by timing exploration and operation activities in light of migration, nesting, and other critical time periods for wildlife. In addition, new technologies designed to lessen these and other impacts can be used, such as double-walled pipes to reduce the risk of oil spills.

Surface impacts from coal mining and oil exploration can temporarily damage habitats during the operation phases until reclamation is complete. To mitigate impacts during mining, for example, storm-water runoff and discharge into undisturbed environments are controlled. After mining is complete, reclamation efforts required by the Surface Mining Control and Reclamation Act restore viable habitats through careful reconstruction of physical and botanical resources. For instance, in the Powder River Basin, as part of reclamation, coal companies strategically place large boulders and other rock material to create wildlife cover and denning habitat. Restoration of wildlife habitat on these reclaimed areas has been quite successful.

In Alaska's Arctic—home to such animals as polar bears, musk oxen, caribou, wolves, and arctic fox—the bitterly cold winters have proven to be beneficial for environmentally responsible energy development. For example, when the North Slope is

frozen and snow-covered, seismic trains can travel across it to gather geophysical information. Furthermore, companies have adopted innovative techniques to reduce the possible impacts of exploration and development. In Alaska's National Petroleum Reserve, the "footprint" from most exploratory wells on federal lands is short-lived and has minimal impact due to the use of ice roads and ice pads that melt with the spring thaw. Advances in extended-reach drilling technologies have also served to minimize environmental effects during energy production activities.

A lengthy 1999 Department of Energy study examined the environmental benefits of new exploration and production technologies and concluded that "improvements over the past 40 years have dramatically reduced industry's footprint on the fragile tundra, have minimized waste produced, and have protected the land for resident and migrating wildlife." The same study concluded that "it is important to tell this remarkable story of environmental progress in E&P [exploration and production] technology. Greater awareness of the industry's achievements in environmental protection will provide the context for effective policy, and for informed decision-making by both the private and public sectors."

Waste Management

Vigilant management and careful disposal of waste from energy extraction and production can prevent the contamination of our air, land, and water. Federal and state authorities are working to ensure that energy projects maintain sound programs to safely handle wastes from mining, drilling, generation and transmission.

Nuclear power plants present waste management challenges unique among energy-generating technologies. They generate spent fuel, as well as other radioactive waste, which must be isolated from ecosystems and human contact for long periods of time. Currently, spent fuel is stored at reactor sites in a number of states, although capacity is limited. Newer technologies have been developed to reduce the volume and

increase the manageability of spent fuel, but such spent fuel will still require safe handling and long-term isolation.

While the federal government has the responsibility to address such high-level wastes, states have the responsibility to address low-level wastes from nuclear plants, such as clothing and equipment. Disposal options for this type of radioactive waste are limited, because siting these facilities has been controversial. In fact, there are only three disposal facilities active in the United States.

Accidental Releases

Since the passage of the Oil Pollution Act in 1990, which, among other things, required double-hulled vessels and improved industry readiness, oil spilled in coastal zone waters has decreased from almost 8 million gallons in 1990 to just over 1 million gallons in 1999. Most energy production facilities implement comprehensive risk-management plans, which reduce the potential for accidents and help local officials prepare for accidents that may arise.

In contrast, inland oil spills do not appear to be decreasing at the same rate as coastal spills. The federal government receives many more inland oil spill notifications (9,000 notifications a year in the early 1990s versus 10,000 to 12,000 a year in the late 1990s), and many very large inland oil spills occur each year (over 100,000 gallons). The continued problem with inland oil spills may be due to aging pipelines, storage tanks, and other infrastructure components.

Since the advent of commercial nuclear power generation, there have been no radiation-related injuries or deaths associated with the operation of a commercial nuclear power plant in the United States. The most significant incident from a nuclear plant in the United States, at Three Mile Island in 1979, prompted improved safety regulation of nuclear plants. New nuclear reactor designs promise even higher safety levels than the reactors currently operating in this country.

Radiation exposure from nuclear facilities is extremely rare. In fact, roughly 82 percent of human exposure to radiation comes from natural sources: radon gas; the human body, which contains radioactive elements; outer space; and rocks and soil. Radon accounts for about 55 percent of our exposure to natural sources of radiation; radioactive elements in our own bodies account for 11 percent; rocks and soil account for 11 percent; and outer space, including the sun, accounts for 8 percent. The remaining 18 percent of average human radiation exposure comes from man-made sources, primarily medical and dental X-rays and consumer products.

The safety of U.S. nuclear energy plants has improved sharply in recent years. A safe nuclear energy plant is one that runs well, experiences few unplanned outages, and has a well-disciplined work force that follows procedures and avoids accidents. The safety of a U.S. nuclear energy plant is typically gauged by monitoring indicators of its performance in these areas: unplanned automatic reactor shutdowns, the annual percentage of possible power generated, and the industrial safety accident rate for plant workers.

In 2000, for the fourth year in a row, the number of unscheduled reactor shutdowns was zero. The industry generated 91.1 percent of its potential maximum output, breaking its 1999 record of 88.7 percent, far better than the typical 80 percent number of ten years ago.

Today, U.S. nuclear plants are more efficient and safer than ever. In the increasingly deregulated marketplace, competition has forced improvements in plant operations that have benefited safety performance as much as economic performance.

Climate Change

Energy-related activities are the primary sources of U.S. man-made greenhouse gas emissions, representing about 85 percent of the U.S. man-made total carbon-equivalent emissions in 1998.

Forests can absorb carbon dioxide, which accounts for the largest share of greenhouse gas emissions. Working with the U.S. Fish and Wildlife Service Research, Illinova Generating Company has voluntarily committed to reforesting 100,000 acres of bottomland hardwood forests on National Wildlife Refuges in the Lower Mississippi River Valley.

Scientists continue to learn more about global climate change, its causes, potential impacts, and possible solutions.

The United States recognizes the seriousness of this global issue as scientists attempt to learn more about climate change. The United States is making progress in reducing emissions of greenhouse gases. Recent data show that the rate of growth in U.S. greenhouse gas emissions has begun to decline, even as the U.S. economy has been growing at an unprecedented rate. For example, historically U.S. CO₂ emissions have grown at roughly half the rate of GDP. In recent years, however, very robust growth in the nation's GDP has been accompanied by a slowdown in the growth of greenhouse gas emissions. In both 1998 and 1999, U.S.

GDP grew by more than 4 percent a year, while CO₂ emissions grew by less than 1.5 percent a year. In addition, the carbon intensity of the U.S. economy—the amount of CO₂ emitted per unit of GDP—declined by 15 percent during the 1990s.

The United States has reduced greenhouse gas emissions by promoting energy efficiency and the broader use of renewable energy through a wide range of public-private partnership programs. These programs save energy, cut energy bills, enhance economic growth, and reduce emissions of conventional air pollutants as well as greenhouse gases.

The U.S. government, businesses, and nongovernmental organizations are sequestering carbon, at home and abroad. For example, working with the U.S. Fish and Wildlife Service Research, Illinova Generating Company has voluntarily committed to reforesting 100,000 acres of bottomland hardwood forests on National Wildlife Refuges in the Lower Mississippi River Valley. It is projected that this project will sequester approximately 13.5 million tons of carbon, improve fish and wildlife populations by restoring the natural forest wetland habitats, and enhance the Gulf of Mexico's near-shore aquatic environment by restoring natural forested wetland filters to the Mississippi River floodplain.

Industry and the federal government are researching various new technologies that will reduce greenhouse gas emissions or sequester those emissions, in geologic formations, oceans, and elsewhere.



Regulatory Structure

The United States has adopted many regulatory protections to limit the environmental damage and public health consequences of the exploration, extraction, production, and use of energy. Most environmental controls are implemented through state or federal permitting or review systems, which often require time for agency review and public participation. Facilities may need several different permits or reviews from different agencies, and they may also need to meet local licensing or zoning laws. Businesses have an interest in moving expeditiously to respond to consumers' needs. The public also has an interest in participating in the system to ensure that appropriate health and environmental precautions will be taken.

Regulatory requirements are not static. New scientific information and new control technologies result in new regulations and modifications to existing regulations over time. However, some level of certainty in the regulatory environment is important for all parties. Businesses can plan more effectively in such an environment, and regulators can focus on ensuring that the desired outcomes are in fact achieved consistently. For example, studies have shown that if electricity generators knew today what their emission requirements for several emissions would be for a defined time period, they would most likely control emissions more cost effectively and sooner than if their emission requirements were decided upon one gas at a time.

Traditional permit and regulatory programs may not always be the most effective and efficient way to protect the environment. Increasingly, regulatory programs are considering approaches that include market-based incentives. These types of incentives offer advantages over traditional forms of regulation because they set high performance standards and then allow market forces to determine the most effective way to meet them. While not appropriate for every situation, market-based incentives can control pollution at a lower cost to society than traditional regulation, stimulate

technological improvements, and be structured to achieve larger reductions in pollution than would result from traditional regulations.

A good example of a U.S. market-based program is the Acid Rain Program, which has reduced SO₂ air emissions from utilities at a fraction of the initial cost estimates. Other emerging market-based environmental protection mechanisms include effluent trading, wetland mitigation banks, tradable development rights, easement purchases, off-site mitigation, and leasing or purchasing of water rights. These programs can reduce mitigation or pollution control costs, increase business flexibility, and provide transparency and environmental protection for the public.



The environmental review process can also be made more open, understandable, predictable, and coordinated among federal agencies and with state and local agencies. It can be improved by providing greater information to clarify expectations for energy developers, facilitating concurrent reviews by federal agencies by standardizing certain information needs, sharing information received by project applicants, and seeking opportunities to integrate required environmental processes and reviews.

Recommendation:

★ The NEPD Group recommends that the President issue an Executive Order to rationalize permitting for energy production in an environmentally sound manner by directing federal agencies to expedite permits and other federal actions necessary for energy-related project approvals on a national basis. This order would establish an interagency task force chaired by the Council on Environmental Quality to ensure that federal agencies responsible for permitting energy-related facilities are coordinating their efforts. The task force will ensure that federal agencies set up appropriate mechanisms to coordinate federal, state, tribal, and local permitting activity in particular regions where increased activity is expected.

Summary of Recommendations

Protecting America's Environment: Sustaining the Nation's Health and Environment

★ The NEPD Group recommends that the President direct the Administrator of the Environmental Protection Agency (EPA) to propose multi-pollutant legislation. The NEPD Group recommends that the President direct the EPA Administrator to work with Congress to propose legislation that would establish a flexible, market-based program to significantly reduce and cap emissions of sulfur dioxide, nitrogen oxides, and mercury from electric power generators. Such a program (with appropriate measures to address local concerns) would provide significant public health benefits even as we increase electricity supplies.

- Establish mandatory reduction targets for emissions of three main pollutants: sulfur dioxide, nitrogen oxides, and mercury.
- Phase in reductions over a reasonable period of time, similar to the successful acid rain reduction program established by the 1990 amendments to the Clean Air Act.
- Provide regulatory certainty to allow utilities to make modifications to their plants without fear of new litigation.
- Provide market-based incentives, such as emissions trading credits to help achieve the required reductions.

★ The NEPD Group recommends the President direct the Secretary of the Interior to work with Congress to create the “Royalties Conservation Fund.”

- This fund will earmark potentially billions of dollars in royalties from new oil and gas production in ANWR to fund land conservation efforts.
- This fund will also be used to eliminate the maintenance and improvements backlog on federal lands.

★ The NEPD Group recommends the President issue an Executive Order to rationalize permitting for energy production in an environmentally sound manner by directing federal agencies to expedite permits and other federal actions necessary for energy-related project approvals on a national basis. This order would establish an interagency task force chaired by the Council on Environmental Quality to ensure that federal agencies responsible for permitting energy-related facilities are coordinating their efforts. The task force will ensure that federal agencies set up appropriate mechanisms to coordinate federal, state, tribal, and local permitting activity in particular regions where increased activity is expected.

Using Energy Wisely

Increasing Energy Conservation and Efficiency

The Department of Energy has installed two low-sulfur light bulbs as a test at its Forrestal Building headquarters in Washington, D.C. The two golf ball-sized bulbs, like those on the opposite page, are at each end of a 240-foot, 10-inch-wide reflective plastic “light pipe.”

U.S. DEPARTMENT OF ENERGY

Energy efficiency is the ability to use less energy to produce the same amount of lighting, heating, transportation, and other energy services. For a family or business, conserving energy means lower energy bills. For the country as a whole, greater energy efficiency helps us make the most of U.S. energy resources, reduces energy shortages, lowers our reliance on energy imports, mitigates the impact of high energy prices, and reduces pollution. Improvements in efficiency can be particularly effective in reducing energy demand when energy is most expensive.

Conservation and energy efficiency are important elements of a sound energy

policy. Improved energy efficiency is the result of many decisions, including those of individual consumers; manufacturers of cars and appliances; home builders; and state, federal, and local government officials. The federal government can promote energy efficiency and conservation by including the dissemination of timely and accurate information regarding the energy use of consumers' purchases, setting standards for more energy efficient products, and encouraging industry to develop more efficient products. The federal government can also promote energy efficiency and conservation through programs like the Energy Star program, and search for more innovative technologies that improve efficiency and conservation through research and development.

Since 1973, the U.S. economy has grown nearly five times faster than energy use (126 percent versus 26 percent). Had Americans continued to use energy as intensively as in 1970, the U.S. would have consumed about 177 quadrillion Btus of energy last year, compared to about 99 quadrillion Btus actually consumed.

British Thermal Unit (Btu)

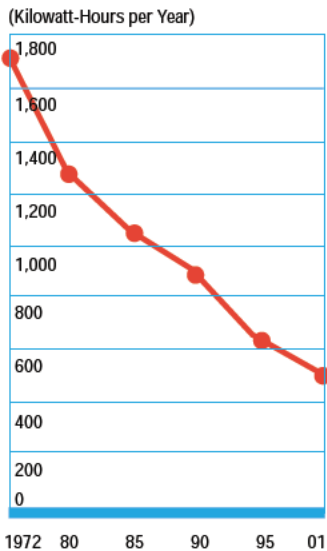
A British thermal unit is the amount of heat required to raise the temperature of one pound of water one degree Fahrenheit at sea level. Put another way, it is approximately the same amount of energy contained in a wooden match head.



U.S. DEPARTMENT OF ENERGY



Figure 4-1
**New Refrigerator-Freezers
 are Using Less Energy**
 Consumption per Unit for
 New Shipments



Over the last thirty years, the energy efficiency of refrigerator-freezer appliances has increased by approximately 70 percent.

Sources: AHAM 2000 Major Home Industry Fact Book and BTS appliance standard.

Improving Efficiency through Innovative Technologies

One measure of energy efficiency is energy intensity—the amount of energy it takes to produce a dollar of gross domestic product (GDP). While about half of the long-term decline in energy intensity can be attributed to changes in the economy, especially the shift from manufacturing to services, the other half reflects improved energy efficiency. Gains in energy efficiency over the last three decades were built on a combination of technological improvements, better management practices, and learning to put these technologies and practices to their best use in automobiles, homes, offices, factories, and farms. In many areas the results have been quite impressive. New home refrigerators use about one-third of the electricity they used in 1972 (Figure 4-1). Compact fluorescent lights use about 25 percent of the electricity of the incandescent bulbs they replace. Automobiles use roughly 60 percent of the gasoline they did in 1972 per mile driven. These individual technological improvements have resulted in significant reductions in energy use (Figure 4-2).

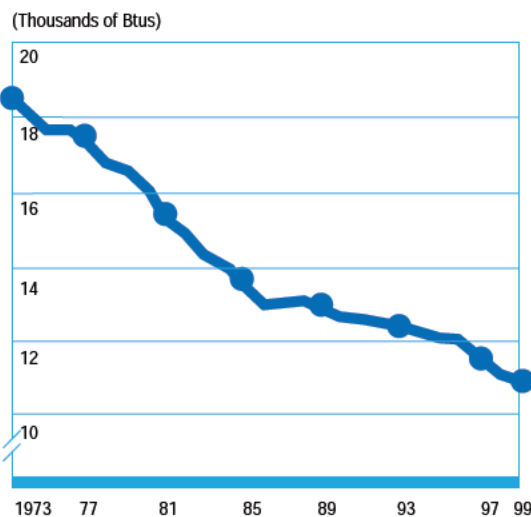
Several new and innovative technolo-

gies offer expanded opportunities to improve our energy efficiency. For example, advanced sensors and controls enable more efficient operation of buildings and factories, and allow equipment and lights to be turned off or dimmed when not in use. Hybrid vehicles use power electronics and battery storage to get more out of every gallon of gasoline consumed, and provide the ability to double vehicle mileage. Cogeneration of electricity and heat and combined heat and power allow for the productive use of much of the waste heat from electricity production, which accounts for about two-thirds of the energy used to produce electricity.

District Energy St. Paul— A Combined Heat and Power Plant

District Energy St. Paul, Inc., is a combined heat and power plant that can operate on natural gas, oil, or clean-burning coal that is mixed with wood chips. These wood wastes come from downed trees, trimmings, and branches. District Energy has been able to keep its rates stable because it is able to rely on a diverse fuel supply. District Energy serves about 75 percent of all building space in the city. Nearly 150 large buildings and 3,200 residential units use the system. It is the largest system of its kind in the nation.

Figure 4-2
**The U.S. Economy Has Become More
 Energy Efficient**



The amount of energy used by the United States in relation to its economic output has steadily declined since the early 1970s.

Source: U.S. Department of Energy, Energy Information Administration.

Recommendation:

★ The NEPD Group recommends that the President direct the Secretary of Energy to conduct a review of current funding and historic performance of energy efficiency research and development programs in light of the recommendations of this report. Based on this review, the Secretary of Energy is then directed to propose appropriate funding of those research and development programs that are performance-based and are modeled as public-private partnerships.

Consumer Choices

The two most important factors in consumers' decisions about purchasing an energy efficient product are price and the life of the product. When energy prices are high, consumers tend to weigh energy efficiency more heavily. Unless consumers are informed about the price of energy, they may not have the incentive to select the most energy efficient product.

Consumers do not receive timely signals about rising electricity costs in order to make adjustments to their energy use and efficiency. When consumers' peak costs are averaged with off-peak costs, the higher cost of peak electricity supplies is masked. As a result, consumers may not recognize the benefits of investing in technologies that best target peak consumption.

Some energy efficiency improvements are easiest and most cost effective to undertake when first building new factories, cars, equipment, appliances, and buildings. Some energy-using equipment, like computers, are used for only a few years before being replaced. Other equipment is used from five to twenty years, such as home appliances, home electronics, and lighting systems. Some capital stock, such as buildings and boilers, can last a half a century or more.

The average car now lasts fourteen years, and newer cars have even more longevity. Vehicle efficiency improvements require significant technological changes. Development of new-car production models requires at least three to four years, which limits the rate at which new technologies can enter the market. Making fundamental changes, such as switching to the use of a fuel cell, would take even longer. Once those new vehicles are in the showroom, it then takes several more years before they constitute any sizable percentage of total vehicles.

In a typical U.S. home, appliances are responsible for about 20 percent of the energy bills. Refrigerators, freezers, clothes washers, dryers, dishwashers, and ranges and ovens are the primary energy-using appliances in most households. Taking steps to save energy while using these appliances, and replacing old inefficient appli-



ances with modern ones can save money.

The federal government established a mandatory program in the 1970s requiring that certain types of new appliances bear a label to help consumers compare the energy efficiency of various products. Under this program, all refrigerators, freezers, clothes washers, and dishwashers are sold with yellow Energy Guide labels to indicate their energy efficiency. These labels provide an estimated annual operating cost of the appliance, and also indicate the cost of operating the models with the highest annual operating cost and the lowest annual operating cost. By comparing a model's annual operating cost with the operating cost of the most efficient model, you can compare their efficiencies. This labeling program ensures that consumers have the information they need to make the right decisions when they purchase major home appliances. However, Energy Guide labels are not currently required for some products, such as kitchen ranges, microwave ovens, clothes dryers, on-demand water heaters, portable space heaters, and lights.

The federal government not only ensures consumers have information on the energy efficiency of major home appliances. It also promotes the most energy efficient products through the Energy Star program, a joint program run by the Department of Energy and the Environmental Protection

Some efficiency improvements are easiest and most cost-effective to undertake when first building new factories, cars, equipment, appliances and buildings.



In April 2001, the Sustainable Buildings Industry Council showcased a net-zero-energy home featuring passive solar design strategies, an integrated photovoltaic system, domestic solar hot water, high-efficiency lights and appliances, and a host of sustainable, market-ready components and systems.

SUSTAINABLE BUILDINGS INDUSTRY COUNCIL



A 48-story skyscraper at the corner of Broadway and 42nd Street in New York City has a photovoltaic skin that uses thin-film PV panels to replace traditional glass cladding material. The PV curtain wall extends from the 35th to the 48th floors on the south and east walls of the tower, making it a highly visible part of the New York City skyline.

U.S. DEPARTMENT OF ENERGY, NATIONAL RENEWABLE ENERGY LABORATORY

Agency. Energy Star is only awarded to appliances that significantly exceed minimum energy efficiency standards. The Energy Star program does not extend to all products. Energy efficiency would be further promoted if the Energy Star program were expanded to a broader range of products.

Recommendation:

★ The NEPD Group recommends that the President direct the Secretary of Energy to promote greater energy efficiency.

- Expand the Energy Star program beyond office buildings to include schools, retail buildings, health care facilities, and homes.
- Extend the Energy Star labeling program to additional products, ap-

pliances, and services.

- Strengthen Department of Energy public education programs relating to energy efficiency.

Energy efficiency can also be improved by the establishment of minimum energy efficiency standards. Congress enacted legislation in 1987 and 1988 to establish minimum energy efficiency standards for many major appliances. These standards apply to manufacturers, not consumers. Appliance manufacturers must produce products that meet the minimum level of energy efficiency. These rules do not affect the marketing of products manufactured before the standards went into effect, and any products made beforehand can be sold. The new standards will stimulate energy savings that benefit the consumer, and reduce fossil fuel consumption, thus reducing air emissions.

These laws established minimum energy efficiency standards for many appliances, including refrigerators, refrigerator-freezers, freezers, room air conditioners, fluorescent lamp ballasts, and incandescent reflector lamps, clothes dryers, clothes washers, dishwashers, kitchen ranges, and ovens, pool heaters, and water heaters. The Energy Policy Act of 1992 added standards for fluorescent and incandescent reflector lamps, plumbing products, electric motors, and commercial water heaters, and heating, ventilation, and air conditioning systems. Under current law, the Department of Energy can raise the minimum energy efficiency standards for these appliances if certain criteria are met, such as cost, technological feasibility, and the impact on competition among appliance manufacturers. In addition, the Department can set energy efficiency standards for appliances not covered by these laws.

Recommendation:

★ The NEPD Group recommends that the President direct the Secretary of Energy to take steps to improve the energy efficiency of appliances.

- Support appliance standards program for covered products, setting higher standards where technologically feasible and economically justified.
- Expand the scope of the appliance standard program, setting standards for additional appliances where technologically feasible and economically justified.

Energy Efficiency

Government Agencies

As the largest energy consumer in the nation, the U.S. government's cost- and energy-saving opportunity is enormous. In 1999, the government consumed nearly 1.1 percent of all U.S. energy and spent nearly \$8 billion for its vehicles, operations, and its nearly 500,000 buildings.

The federal government has reduced its energy use in buildings by about 30 percent from 1990 levels, largely by installing energy efficient technologies (Figure 4-3). It has reduced its energy use for vehicles and equipment by 35 percent. Some of these improvements are attributable to the Department of Energy, whose Federal Energy Management Program helps government agencies reduce their energy and water use, manage their utility costs, and promote renewable energy.

Recommendations:

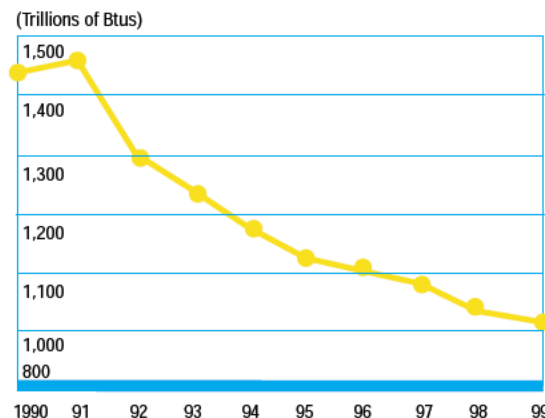
- ★ The NEPD Group recommends that the President direct heads of executive departments and agencies to take appropriate actions to conserve energy use at their facilities to the maximum extent consistent with the effective discharge of public responsibilities. Agencies located in regions where electricity shortages are possible should conserve especially during periods of peak demand.
- Agencies should report to the President, through the Secretary of Energy, within 30 days of the conservation actions taken.

State and local governments have unique opportunities for energy savings in schools, transportation, state buildings, and building codes. For example, the Texas School Energy Management Program could save school districts as much as \$100 million in energy costs every year by helping school districts evaluate their energy needs and resources. Similarly, Wisconsin's Energy Initiative is working with utilities to make basic changes to public buildings. By installing new lighting fixtures and taking other steps, Wisconsin estimates that it will save \$60 million in state spending on energy over ten years.

Residential and Commercial Buildings

There are significant opportunities to improve the energy efficiency of buildings and homes through technologies and better practices. For existing homes, immediate options for improving efficiency include reducing air infiltration with caulking and weather stripping, installing modern thermostats, sealing ductwork, and adding insulation. These steps can reduce the 40 percent share of residential energy bills that

Figure 4-3
The U.S. Government is Reducing Its Energy Consumption



During the 1990s, energy use in federal buildings decreased by about 30 percent.

Source: U.S. Department of Energy, Energy Information Administration.



PULTE HOMES

Building America—Pulte Homes

Pulte Homes Southwest Division has used technical assistance from the Department of Energy's Building America program to create what one residential expert calls "the best production house in the world," which won the 2001 National Association of Home Builders' Energy Value Award. In Tucson, Phoenix, and Las Vegas, Pulte Homes has worked with the Department of Energy to redesign the energy features of its basic models.

Using advanced insulation techniques, highly efficient equipment and windows, and right-sized heating and cooling systems, the homes look the same, but perform so well they use half the energy for heating and cooling at virtually no increase in construction costs.

The whole building/systems engineering approach used in the Building America program allows builders to add more insulation and more efficient windows while reducing the size of the heating and cooling equipment. The trade-off means no added cost to the builder, better value for the buyer, reduced electric load for the utility, and improved affordability.

go toward heating and cooling. Additional savings are possible when efficient appliances are purchased or major home renovations are undertaken. Installing a new, more efficient gas furnace can save up to 20 percent annually on natural gas. New buildings offer the greatest energy efficiency opportunities and can be designed to be both more comfortable and more efficient, cutting heating and cooling costs by close to 50 percent.

In commercial buildings, typically the quickest, most cost effective way to increase energy efficiency is to replace the lighting systems. Sensors help to avoid 24-hour operation of lights and equipment that are only used for a portion of the day. As with homes, advances in windows, heating and air conditioning systems, overall building designs, and equipment and appliances present significant energy saving opportunities.

Many families and businesses can face obstacles to realizing energy cost reductions.

Insufficient Information

Monthly energy bills generally report only total electricity or natural gas used, leaving families and businesses unsure about which energy services are most responsible for their energy use, and which investments could best help them reduce their costs. In addition, consumers may be unsure about the credibility of the energy-saving claims of individual manufacturers, salesmen, and designers. This incomplete information causes imperfections in the marketplace that hinder purchases of efficient technologies that would actually save families and businesses money.

Lack of Availability

Frequently, the most energy efficient products cost more and are not widely available, especially in smaller communities. Builders who would like to construct more efficient homes and businesses face the same problem at the wholesale level. For example, to keep costs down, builders are less likely to install top-of-the-line,

highly efficient products. The less expensive and generally less efficient products are heavily stocked and deeply discounted due to volume ordering. The decisions made about the energy efficiency of buildings and homes are not usually made by the consumer who will ultimately pay the energy bills. The incentive is for the builders to choose the material that poses the least cost to the builder, which is not necessarily the most energy efficient choice.

Lack of Automation

People often walk out of their offices and homes with the lights on and the air conditioner running. Turning off unused appliances, electronics, and lights is not always easy. Lack of automation (e.g., daylight sensors) means that conservation mostly depends on people turning off switches. Some appliances and electronics, such as stereos, video tape players, and televisions, continue to use electricity even after they are turned off.

Higher Initial Costs

Efficient products often cost more than less efficient versions, especially when they are first introduced to the market. Unless consumers can verify the resulting savings, they may be reluctant to pay the additional costs. Businesses that adopt labeling programs that spell out energy savings may be more successful in selling a more efficient, yet initially more expensive product. Higher initial costs can be particularly difficult for the purchaser or builder of a new home or office building.

Industry and Agriculture

Six industries consume three-quarters of all industrial energy: lumber and paper; chemicals; petroleum refining; primary metals; food processing; and stone, clay, and glass. Improved energy efficiency in these energy-intensive industries yields even larger improvements in overall productivity, product quality, safety, and pollution prevention. Manufacturing companies generally obtain their largest savings from



improved efficiency of motors (motors account for 54 percent of electricity use in manufacturing) and from improved steam and hot-water systems. Many companies can reduce energy needs further by cogenerating their electricity and heat for steam.

Energy use for U.S. agriculture grew during the 1960s and 1970s, peaking in 1978. High energy prices during the 1970s and early 1980s caused many farmers to find ways to reduce their energy costs, such as by switching from gasoline-powered to more fuel-efficient diesel-powered engines, adopting conservation tillage practices, shifting to larger multiprocessor machines, and using energy saving methods for drying and irrigating crops. These measures helped farmers reduce their energy use by 41 percent from 1978 to 1998, while agricultural output grew by about 40 percent over the same period.

Farmers can reap additional energy savings as they replace old machinery with more energy efficient equipment. Furthermore, farmers can adopt more advanced practices, such as precision farming, that optimize the use of machines, chemicals, and fertilizers to achieve energy savings. New seed varieties can also reduce energy-intensive chemical requirements.

Despite the opportunity for increased energy efficiency, the industrial and agricultural sectors face several obstacles. Because many manufacturing and farming operations are highly specialized, they need specific information on energy-saving opportunities to effectively respond to energy price signals and supply problems.

High energy prices during the 1970s and early 1980s caused many farmers to find ways to reduce their energy costs, such as by switching from gasoline-powered to more fuel efficient diesel-powered engines and by adopting conservation tillage practices.

Cogeneration

In 1998, Malden Mills Industries, a textile manufacturer employing 2,300 workers in Lawrence, Massachusetts, installed a state-of-the-art combined heat and power (CHP) facility. The system uses two 4.3 MW industrial gas turbines, retrofitted with ceramic combustion liners, that were developed as part of the Department of Energy's Advanced Turbine Systems program, and that enable higher operating temperatures and lower emissions. The CHP system saves Malden Mills more than \$1 million annually. The liners have accumulated more than 9,500 hours of successful operation and have cut emissions of nitrogen oxides and carbon monoxide to less than 15 parts per million.



In order for manufacturing or agriculture to switch to more efficient energy products and practices, significant costs are incurred due to production delays, waste and spoilage, and labor costs. As a result, manufacturers and farmers tend to use readily available and reliable equipment when upgrading, instead of untested, newer products and approaches.

Because of their large needs for both heat and electricity, businesses find combined heat and power (CHP) systems particularly attractive. However, replacing old, inefficient boilers with highly efficient CHP systems may add a number of new regulatory requirements (such as air permits), but does not offer the same tax depreciation incentives the tax code grants to power plants.

Recommendations:

★ The NEPD Group recommends that the President direct the Secretary of the Treasury to work with the Congress on legislation to encourage increased energy efficiency through combined heat and power (CHP) projects by shortening the depreciation life for CHP projects or providing an investment tax credit.

★ The NEPD Group recommends that the President direct the Administrator of the Environmental Protection Agency (EPA) to work with local and state governments to promote the use of well-designed CHP and other clean power generation at brownfield sites, consistent with the local communities' interests. EPA will also work to clarify liability issues if they are raised at a particular site.

★ The NEPD Group recommends that the President direct the EPA Administrator to promote CHP through flexibility in environmental permitting.

Conservation can be improved by car pooling, telecommuting, increasing public transit choices, and pricing highway use during periods of peak demand.

Transportation

Transportation plays a key role in a growing U.S. economy, comprising 16 percent of GDP in 1998, 10.5 percent of total employment, and 27 percent of total U.S. energy consumption. Trucks and automobiles account for over three-fourths of the sector's petroleum use, with the remainder attributable to rail, ship, air, and pipeline systems. Mass transit ridership has increased by 21 percent since 1996. Automobiles today use roughly 60 percent of the gasoline they did in 1972 per mile driven, due in part to new technology, such as better engine and design controls, improved transmission, weight reduction, and improved aerodynamics. Despite the adoption of more efficient transportation technologies, average fuel economy for passenger vehicles has remained relatively flat for ten years and is, in fact, at a twenty-year low, in large part due to the growth and popularity of low-fuel-economy pickup trucks, vans, and sport utility vehicles (Figure 4-4).

Recommendation:

★ The NEPD Group recommends that the President direct the Secretary of Transportation to:

- Review and provide recommendations on establishing Corporate Average Fuel Economy (CAFE) standards with due consideration of the National Academy of Sciences study to be released in July 2001. Responsibly crafted CAFE standards should increase efficiency without negatively impacting the U.S. automotive industry. The determination of future fuel economy standards must therefore be addressed analytically and based on sound science.
- Consider passenger safety, economic concerns, and disparate impact on the U.S. versus foreign fleet of automobiles.
- Look at other market-based approaches to increasing the national average fuel economy of new motor vehicles.

Opportunities for reducing oil demand in the transportation sector include increasing conservation, vehicle efficiency, and alternative fuels. Conservation can be improved by car pooling, telecommuting, and increasing transit choices. For example, an increase in the average fuel economy of the on-road vehicle fleet by three miles per gallon would save one million barrels of oil a day, or about half of the global shortfall between supply and demand that triggered the oil price increases since 1998. In addition, fuel conservation can be further improved by technologies to reduce congestion.

A recent analysis indicates that the fuel economy of a typical automobile could be enhanced by 60 percent by increasing engine and transmission efficiency and reducing vehicle mass by about 15 percent. Several promising efficiency technologies are being presented to the U.S. market. For example, some automobile manufacturers have already introduced hybrid vehicles, and others have announced that they will introduce hybrid vehicles within the next several years. Advanced lightweight materials offer up to 6 percent improvement in mileage for each 10 percent reduction in body weight. Although promising, it may be many years before hybrids become a substantial part of the automotive fleet.

Recommendations:

★ The NEPD Group recommends that the President direct the Secretary of Transportation to review and promote congestion mitigation technologies and strategies and to work with the Congress on legislation to implement these strategies.

★ The NEPD Group recommends that the President direct the Secretary of the Treasury to work with Congress on legislation to increase energy efficiency with a tax credit for fuel-efficient vehicles. The NEPD Group recommends that a temporary, efficiency-based income tax credit be available for purchase of new hybrid or fuel cell vehicles between 2002 and 2007.

Higher Initial Production Costs

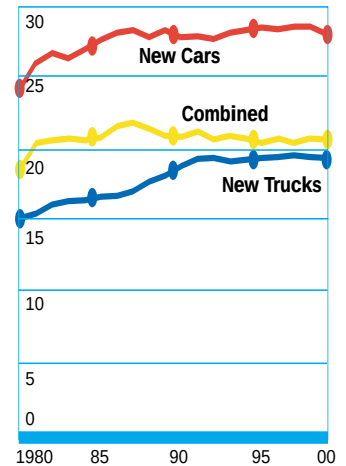
Because of the large economies of scale in automobile manufacturing, new technologies with limited early production runs often enter the market at higher initial costs. In this highly competitive international market, higher initial production costs can be a significant impediment to the introduction of new technologies. Unless U.S. automakers can remain competitive with their overseas counterparts, it is unlikely they will invest in new, more efficient technologies. Vehicle efficiency technologies, such as advanced engines, fuel cells, and cutting-edge electronic drive-train technologies, will become widely available only when component costs are reduced or demand is increased.

Hybrid Vehicles

The engine of a conventional gasoline vehicle is typically sized for the small amount of time the driver spends accelerating to enter the freeway, to pass another car, or to climb a hill. Most of the time it operates at less than 20 percent efficiency. An attractive alternative is to use a hybrid system that allows the engine to operate at peak efficiency, and get a boost from a battery when entering the freeway or climbing a hill. Not only does this system allow improved performance from a smaller engine, but the energy usually lost in stopping the car can be recovered and stored in the battery.

What does this mean to the average American? Significantly improved fuel economy and reduced emissions.

Figure 4-4
Fuel Efficiency of Light Vehicles Has Remained Flat
(Miles per Gallon)



Despite the adoption of more efficient transportation technologies, U.S. average fuel economy has been flat for 10 years. In large part, this is due to the growth of low-fuel-economy pickup trucks, vans, and sport utility vehicles.

Source: U.S. Department of Energy, Energy Information Administration.

Summary of Recommendations

Using Energy Wisely: Increasing Energy Conservation and Efficiency

- ★ The NEPD Group recommends that the President direct the Office of Science and Technology Policy and the President's Council of Advisors on Science and Technology to review and make recommendations on using the nation's energy resources more efficiently.
- ★ The NEPD Group recommends that the President direct the Secretary of Energy to conduct a review of current funding and historic performance of energy efficiency research and development programs in light of the recommendations of this report. Based on this review, the Secretary of Energy is then directed to propose appropriate funding of those research and development programs that are performance-based and are modeled as public-private partnerships.
- ★ The NEPD Group recommends that the President direct the Secretary of Energy to promote greater energy efficiency.
 - Expand the Energy Star program beyond office buildings to include schools, retail buildings, health care facilities, and homes.
 - Extend the Energy Star labeling program to additional products, appliances, and services.
 - Strengthen Department of Energy public education programs relating to energy efficiency.
- ★ The NEPD Group recommends that the President direct the Secretary of Energy to improve the energy efficiency of appliances.
 - Support the appliance standards program for covered products, setting higher standards where technologically feasible and economically justified.
 - Expand the scope of the appliance standards program, setting standards for additional appliances where technologically feasible and economically justified.
- ★ The NEPD Group recommends that the President direct heads of executive departments and agencies to take appropriate actions to conserve energy use at their facilities to the maximum extent consistent with the effective discharge of public responsibilities. Agencies located in regions where electricity shortages are possible should conserve especially during periods of peak demand. Agencies should report to the President, through the Secretary of Energy, within 30 days on the conservation actions taken.
- ★ The NEPD Group recommends that the President direct the Secretary of the Treasury to work with Congress to encourage increased energy efficiency through combined heat and power (CHP) projects by shortening the depreciation life for CHP projects or providing an investment tax credit.
- ★ The NEPD Group recommends that the President direct the Administrator of the Environmental Protection Agency (EPA) to work with local and state governments to promote the use of well-designed CHP and other clean power generation at brownfields sites, consistent with the local communities' interests. EPA will also work to clarify liability issues if they are raised at a particular site.
- ★ The NEPD Group recommends that the President direct the EPA Administrator to promote CHP through flexibility in environmental permitting.
- ★ The NEPD Group recommends that the President direct the Secretary of Transportation to:
 - Review and provide recommendations on establishing Corporate Average Fuel Economy (CAFE) standards with due consideration of the National Academy of Sciences study to be released in July 2001. Responsibly

crafted CAFE standards should increase efficiency without negatively impacting the U.S. automotive industry. The determination of future fuel economy standards must therefore be addressed analytically and based on sound science.

- Consider passenger safety, economic concerns, and disparate impact on the U.S. versus foreign fleet of automobiles.
- Look at other market-based approaches to increasing the national average fuel economy of new motor vehicles.

★ The new NEPD Group recommends that the President direct the Secretary of Transportation to review and promote congestion mitigation technologies and strategies and work with Congress on legislation to implement these strategies.

★ The NEPD Group recommends that the President direct the Secretary of the Treasury to work with Congress on legislation to increase energy efficiency with a tax credit for fuel-efficient vehicles. The NEPD Group recommends that a temporary, efficiency-based income tax credit be available for purchase of new hybrid fuel cell vehicles between 2002 and 2007.

★ The NEPD Group recommends that the President direct all agencies to use technological advances to better protect our environment.

- The Administration remains committed to investing in Intelligent Transportation Systems (ITS) and encourages the private sector to invest in ITS applications. This Department of Transportation (DOT) program funds the development of improved transportation infrastructure that will reduce congestion, such as traveler information/navigation systems, freeway management, and electronic toll collection. ITS applications reduce fuel associated with travel.
- The Administration remains committed to the DOT's fuel-cell-powered transit bus program, authored by the Transportation Equity Act for the 21st Century (TEA-21). This program demonstrates the viability of fuel-cell power plants for transit bus applications.
- The Administration remains committed to the Clean Buses program. TEA-21 establishes a new clean fuel formula grant program, which provides an opportunity to accelerate the introduction of advanced bus propulsion technologies into the mainstream of the nation's transit fleet.

★ The NEPD Group recommends that the President direct the EPA and DOT to develop ways to reduce demand for petroleum transportation fuels by working with the trucking industry to establish a program to reduce emissions and fuel consumption from long-haul trucks at truck stops by implementing alternatives to idling, such as electrification and auxiliary power units at truck stops along interstate highways. EPA and DOT will develop partnership agreements with trucking fleets, truck stops, and manufacturers of idle-reducing technologies (*e.g.*, portable auxiliary packs, electrification) to install and use low-emission-idling technologies.

★ The NEPD Group recommends that the President direct the Secretary of Energy to establish a national priority for improving energy efficiency. The priority would be to improve the energy intensity of the U.S. economy as measured by the amount of energy required for each dollar of economic productivity. This increased efficiency should be pursued through the combined efforts of industry, consumers, and federal, state, and local governments.

★ The NEPD Group recommends that the President direct the EPA Administrator to develop and implement a strategy to increase public awareness of the sizable savings that energy efficiency offers to homeowners across the country. Typical homeowners can save about 30 percent (about \$400) a year on their home energy bill by using Energy Star-labeled products.

Energy for a New Century

Increasing Domestic Energy Supplies

America's energy strength lies in the abundance and diversity of its energy resources, and in its technological leadership in developing and efficiently using these resources. Our nation has rich deposits of coal, oil, and natural gas. The United

States is the third-largest oil-producing nation in the world, despite a thirty-year decline in domestic production. While our economy runs primarily on fossil fuels, we also have long experience with hydropower and nuclear energy. We are pursuing the ability to further capture the energy of sunlight, the heat of the earth, and the power of wind.

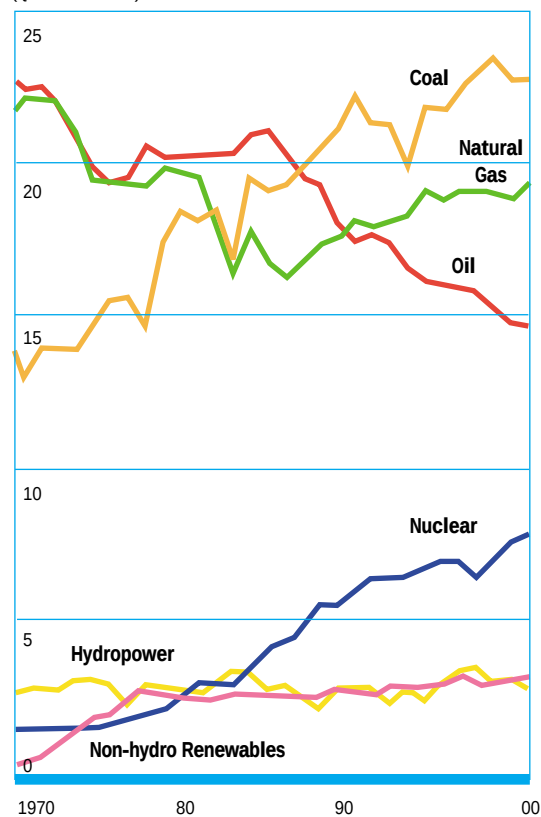
Economic factors will help determine the future development of our nation's energy sources. These factors will be shaped not only by conservation, energy demand, and the cost of energy development, but also by the regulations that federal, state, and local governments put in place to balance energy needs with legitimate competing aims, including the protection of the environment. A number of factors will make it difficult to increase domestic energy production in response to the growing demand for energy: economic and technological factors associated with depletion of the fossil fuel resource base in the U.S.; regulatory uncertainty; limitations on access to federal lands with high potential for new discoveries; infrastructure constraints, such as electricity transmission and gas pipeline bottlenecks; and conflicts with legitimate land use, environmental, and other public policy goals.

The United States has significant domestic energy resources, and remains a major energy producer. Between 1986 and 2000, production of coal, natural gas, nuclear energy, and renewable energy increased. However, these increases have been largely offset by declines in oil production (Figure 5-1).

Figure 5-1

U.S. Energy Production: 1970–2000

(Quadrillion Btus)



Production of coal, the nation's most abundant fuel source, exceeded 1 billion tons in 2000. Electricity generation accounted for about 90 percent of U.S. coal consumption last year.

Source: U.S. Department of Energy, Energy Information Administration.



Even with improved energy efficiency, the United States will need more energy supply. U.S. energy demand is projected to rise to 127 quadrillion Btus by 2020, even with significantly improved energy efficiency. However, domestic production is expected to rise to only 86 quadrillion Btus by 2020. The shortfall between projected energy supply and demand in 2020 is nearly 50 percent. That shortfall can be made up in only three ways: import more energy; improve energy efficiency even more than expected; and increase domestic energy supply.

The challenge for our nation is to use technology to maintain and enhance the diversity of our supplies, thus providing a reliable and affordable source of energy for Americans. These goals can and must be accomplished while maintaining our commitment to environmental protection.

Oil and Natural Gas

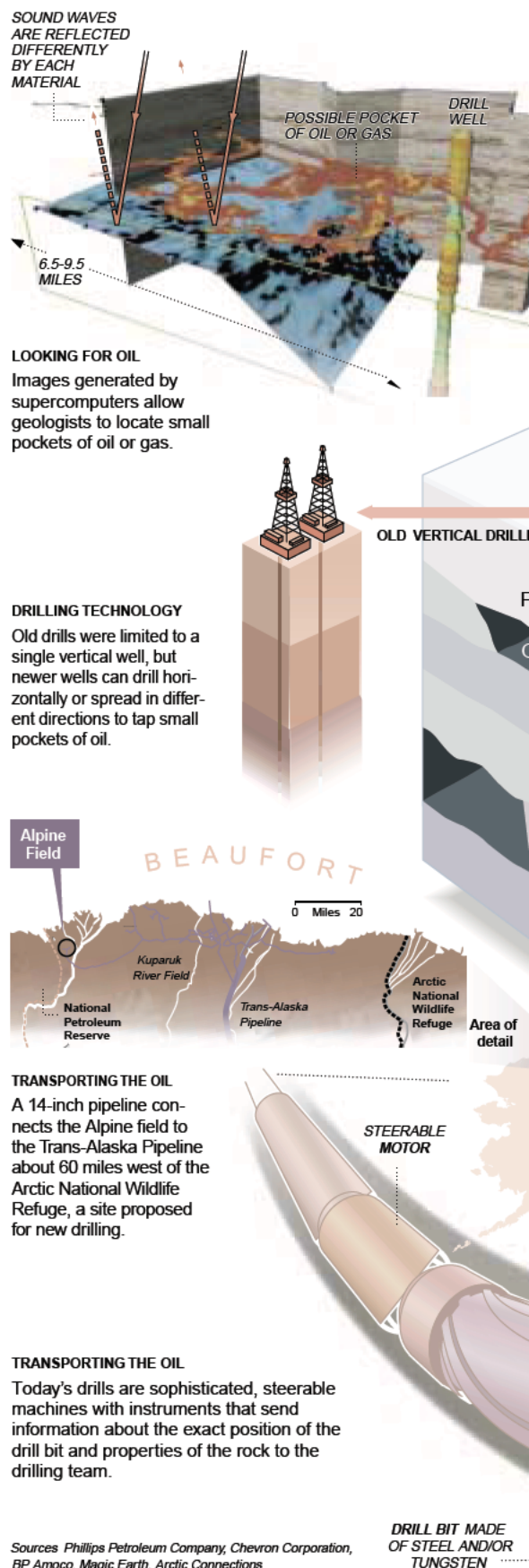
Oil and natural gas are the dominant fuels in the U.S. economy, providing 62 percent of the nation's energy and almost 100 percent of its transportation fuels. By 2020, the Energy Information Administration expects the United States will need about 50 percent more natural gas and one-third more oil to meet demand.

U.S. oil production is expected to decline over the next two decades. Over the same period, demand for natural gas will most likely continue to outpace domestic production. As a result, the United States will rely increasingly on imports of both natural gas and oil from Canada, and imports of oil and liquefied natural gas from producers across the globe.

21st Century Technology

Remaining U.S. oil reserves are becoming increasingly costly to produce because much of the lower-cost oil has already been largely recovered. The remaining resources have higher exploration and production costs and greater technical challenges, because they are located in geologically complex reservoirs, (e.g., deep water

Figure 5-2



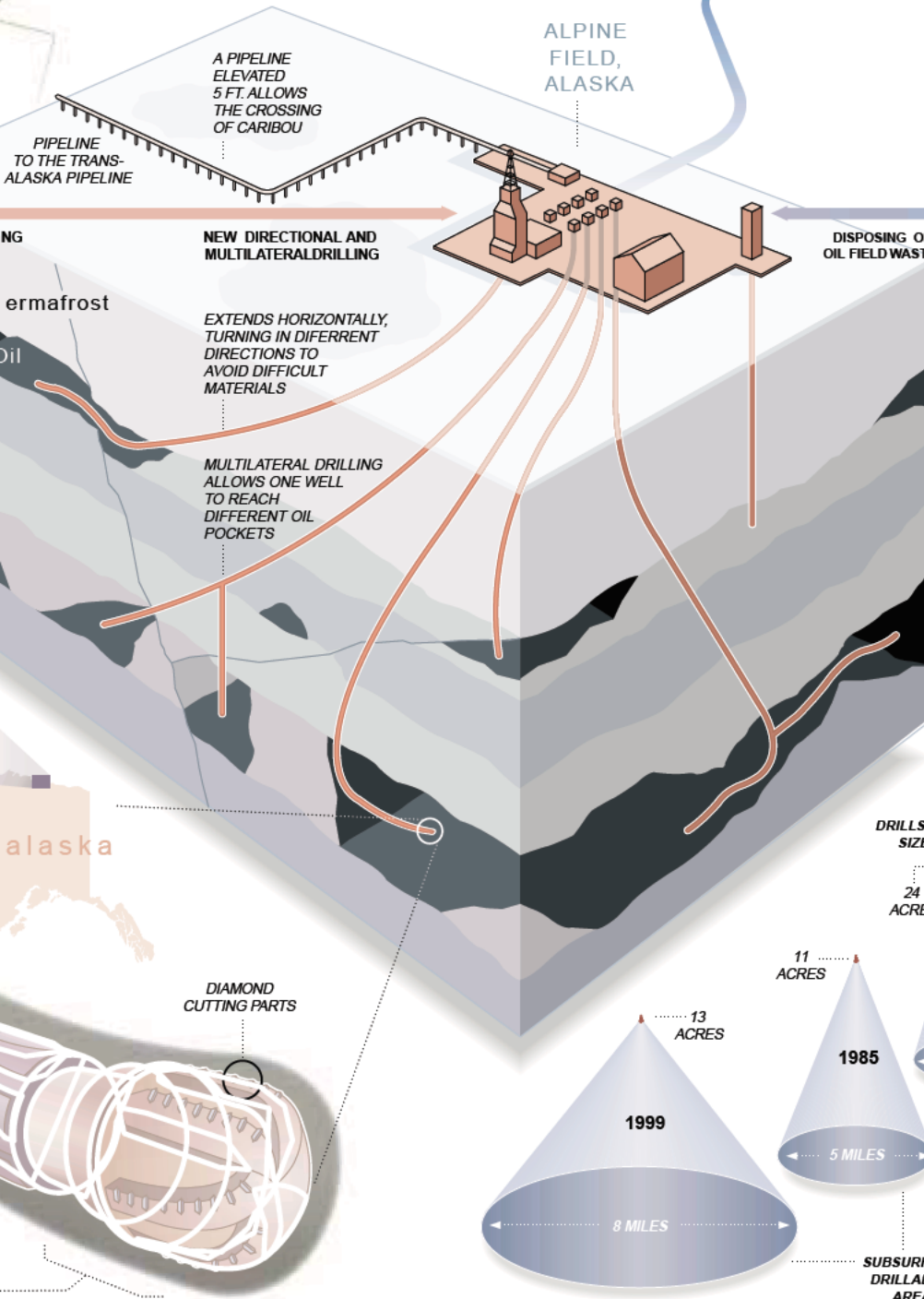
Using the Latest Drilling Technology to Reduce Environmental Damage

Oil drilling sites like those in the Alpine field on Alaska's North Slope are using cutting-edge technology in hopes of reducing environmental damage.

Recent advances are lessening the industry's impact on the fragile Arctic ecosystem.



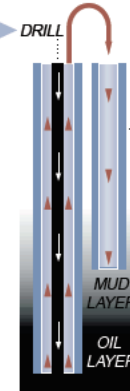
BP Amoco



GETTING THERE

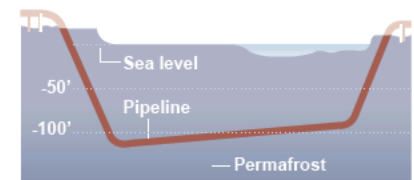
To minimize the project's impact on the environment, temporary ice roads are used in the winter, leaving few traces after they thaw.

MUD/ROCK PUMPING, CRUSHING AND INJECTION



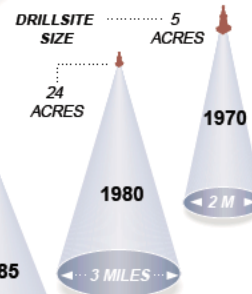
DISPOSING OF WASTES

Mud and debris from drilling used to be placed in big reserve pits. Today, rock cuttings are crushed, mixed with the mud, and sent deep into the earth where they originated. This minimizes the size of well pads.



CROSSING A RIVER

Although traditional pipelines are built above ground, the pipeline to the Trans-Alaska Pipeline plunges beneath the Colville River, preserving the surface and the river bed environment.



OCCUPYING LESS OF THE TUNDRA

The new drilling technology allows for smaller surface production pads and larger areas explored in the earth.

Source: New York Times News Service

21st Century Technology: The Key to Environmental Protection and New Energy Production

Producing oil and gas from geologically challenging areas while protecting the environment is important to Americans and to the future of our nation's energy security. New technology and management techniques allow for sophisticated energy production as well as enhanced environmental protection. A technology evolution has occurred in the way oil and natural gas are found. The computer, three dimensional seismic technology, and other technologies have transformed the process from one based on "feel," to one highly dependent on the most advanced and sophisticated technology available. These technologies reduce cost and protect the environment.

Today's oil and gas exploration technology, for example, is boosting the success rate of pinpointing new resources. The results: fewer dry holes, reduced waste volumes, and a cleaner environment. Smaller, lighter drilling rigs coupled with advances in directional and extended-reach drilling significantly increase protection of the environment.

- Advanced, more energy efficient drilling and production methods:
 - reduce emissions;
 - practically eliminate spills from offshore platforms; and
 - enhance worker safety, lower risk of blowouts, and provide better protection of groundwater resources.
- With each improvement in operational performance and efficiency, more oil and gas resources can be recovered with fewer wells drilled, resulting in smaller volumes of:
 - cuttings;
 - drilling muds and fluids; and
 - produced waters.
- Modular drilling rigs, "slimhole" drilling, directional drilling, and other advances enable:
 - production of oil and gas with increased protection to wetlands and other sensitive environments;
 - reduced greenhouse gas emissions;
 - and worker safety through the use of innovative best management practices.

Other examples of advanced technology include:

- 3-D seismic technology that enables geologists to use computers to determine the location of oil and gas before drilling begins, dramatically improving the exploration success rate;
- deep-water drilling technology that enables exploration and production of oil and gas at depths over two miles beneath the ocean's surface;
- high-powered lasers that may one day be used for drilling for oil and gas; and
- highly sophisticated directional drilling that enables wells to be drilled long horizontal distances from the drilling site.

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and harsh environments).

While the resource base that supplies today's natural gas is vast, U.S. conventional production is projected to peak as early as 2015. Increasingly, the nation will have to rely on natural gas from unconventional resources, such as tight sands, deep formations, deep water, and gas hydrates. Also, many resources are in environmentally sensitive areas that require use of less intrusive technologies.

New technologies are being developed to reduce both the environmental effects and the economic costs of exploration for oil and gas. These exciting new technologies, like horizontal drilling and three-dimensional seismic technology allow for much greater precision and significantly less impact on the environment (Figure 5-2).

Small independent businesses account for 50 and 65 percent, respectively, of domestic petroleum and natural gas production in the lower 48 states. However, even when new technology is available, independent producers can lack the investment capital needed to apply the technology and be unable to cope with the increased economic and technical risks associated with harder-to-recover resources.

For example, most new gas wells drilled in the United States will require hydraulic fracturing. This is a common procedure used by producers to complete gas wells by stimulating the well's ability to flow increased volumes of gas from the reservoir rock into the wellbore. During a fracture procedure, fluid and a propping agent (usually sand) are pumped into the reservoir rock, widening natural fractures to provide paths for the gas to migrate to the wellbore. In certain formations, it has been demonstrated that the gas flow rate may be increased as much as twenty-fold by hydraulic fracturing. Each year nearly 25,000 oil and gas wells are hydraulically fractured.

The use of hydraulic fracturing in natural gas production from coal seams is one of the fastest-growing sources of gas production. This source will most likely face added controls, and costs to ensure that disposal (by re-injection or discharge) of production waters is done in an environmentally sensitive manner.

For each of these issues, opportunities exist to better coordinate, improve performance, and meet America's energy, public health, safety and environmental goals.

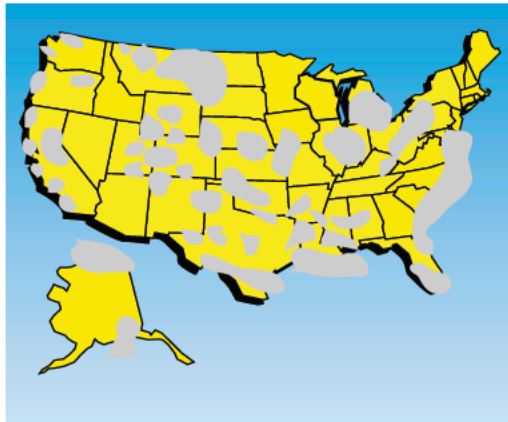
Recommendation:

★ The NEPD Group recommends that the President direct the Secretaries of Energy and the Interior to promote enhanced oil and gas recovery from existing wells through new technology.

Small independent businesses account for 50 and 65 percent, respectively, of domestic petroleum and natural gas production in the lower 48 states.

Anywhere from 30 to 70 percent of oil, and 10 to 20 percent of natural gas, is not recovered in field development. It is estimated that enhanced oil recovery projects, including development of new recovery techniques, could add about 60 billion barrels of oil nationwide through increased use of existing fields (Figure 5-3).

Figure 5-3
Major U.S. Oil and Gas Fields



The United States is the most mature oil-producing region in the world, and much of our easy-to-find resource base has been depleted. Advanced exploration and production technologies of the past two decades have played a key role in recovering additional oil and natural gas from existing fields.

Source: U.S. Department of Energy, Energy Information Administration.

Public Lands Leasing

The federal government owns about 31 percent of the nation's land, so it can have a major role in increasing energy production in appropriate places. A large portion of U.S. energy resources are contained in these federal lands and offshore areas. Public lands provide nearly 30 percent of

annual national energy production, and are estimated to contain a substantial majority of the nation's undiscovered domestic energy resources.

Portions of federal onshore and offshore lands are off-limits to oil and gas exploration and development. Access is restricted for a variety of reasons, including administrative land withdrawals for competing land uses, such as national defense or water projects; and stipulations affecting surface occupancy, use, and timing for environmental compatibility.

Recommendations:

★ The NEPD Group recommends that the President direct the Secretary of the Interior to examine land status and lease stipulation impediments to federal oil and gas leasing, and review and modify those where opportunities exist (consistent with the law, good environmental practice, and balanced use of other resources).

- Expedite the ongoing Energy Policy and Conservation Act study of impediments to federal oil and gas exploration and development.
- Review public lands withdrawals and lease stipulations, with full public consultation, especially with the people in the region, to consider modifications where appropriate.

★ The NEPD Group recommends that the President direct the Secretary of the Interior to consider economic incentives for environmentally sound offshore oil and gas development where warranted by specific circumstances: explore opportunities for royalty reductions, consistent with ensuring a fair return to the public where warranted for enhanced oil and gas recovery; for reduction of risk associated with production in frontier areas or deep gas formations; and for development of small fields that would otherwise be uneconomic.

Offshore

Congress has designated about 610 million acres off limits to leasing on the Outer Continental Shelf (OCS), which contains large amounts of recoverable oil and gas resources. These Congressional moratoria have been expanded by Presidential action through 2012, effectively confining the federal OCS leasing program to the central and western Gulf of Mexico, a small portion of the eastern Gulf, existing leases off California's shore, and areas off of Alaska.

Concerns over the potential impacts of oil spills have been a major factor behind imposition of the OCS moratoria. For areas that are available for possible development, it is projected that with advanced technology, we could recover 59 billion barrels of oil and 300 trillion cubic feet of natural gas. This type of exploration and production from the OCS has an impressive environmental record. For example, since 1985, OCS operators have produced over 6.3 billion barrels of oil, and have spilled only 0.001 percent of production. Naturally occurring oil seeps add about 150 times as much oil to the oceans. Additionally, about 62 percent of OCS energy production is natural gas, which poses little risk of pollution.

For those areas that are available for potential coastal zone and OCS exploration and production activity, businesses must comply with a variety of federal and state statutes, regulations, and executive orders. Aspects of these, under the Coastal Zone Management Act and the Outer Continental Shelf Lands Act and their regulations, attempt to provide for responsible development while considering important environmental resources. However, effectiveness is sometimes lost through a lack of clearly defined requirements and information needs from federal and state entities, as well as uncertain deadlines during the process. These delays and uncertainties can hinder proper energy exploration and production projects.

The Deep Water Royalty Relief Act of 1995, granting variable royalty reductions for new leases in deep water, contributed to a significant increase in deep-water leasing in the central and western Gulf over the last five years. The opportunities created in deep water help spur the development of new

technologies and infrastructure for this frontier area. However, substantial economic risks remain to investment in deep water and continued incentives could help draw investment in other countries. Similar incentives could spur development in other technological frontiers, such as deep gas, or make possible continued production from both offshore and onshore fields near the end of their economic life.

Recommendation:

★ The NEPD Group recommends that the President direct the Secretaries of Commerce and Interior to re-examine the current federal legal and policy regime (statutes, regulations, and Executive Orders) to determine if changes are needed regarding energy-related activities and the siting of energy facilities in the coastal zone and on the Outer Continental Shelf (OCS).

Arctic Outer Continental Shelf

It is estimated there are significant undiscovered resources in the two planning areas of the Arctic OCS. Geologists estimate that there are approximately 22.5 billion barrels of oil and 92 trillion cubic feet of natural gas in the Arctic OCS. The Beaufort Sea Planning Area encompasses approximately 65 million acres. Active leases within the Beaufort Sea Planning Area represent only 0.4 percent of the total acreage, and only 5 percent of the leased acreage is being actively pursued for development and production. The Chukchi Sea Planning Area encompasses approximately 63.7 million acres, none of which is currently leased.

Lease offerings totaling 58 million acres over the past twenty years have resulted in 34 exploratory wells. Two oil discoveries are now moving toward production, but economic factors have delayed several others. These discoveries have estimated recoverable reserves of more than 260 million barrels of oil. This is another area where periodic, well-scheduled lease sales can help contribute to national energy production.



The high-technology oil industry requires an educated, technologically sophisticated work force. Many workers left the industry in the mid-1980s because of job insecurity caused by price volatility. The lack of an experienced work force today may limit the amount and increase the cost of future exploration and production activity.

U.S. DEPARTMENT OF ENERGY

Recommendation:

★ The NEPD Group recommends that the President direct the Secretary of the Interior continue OCS oil and gas leasing and approval of exploration and development plans on predictable schedules.

Onshore

North Slope Oil and Gas

The Alaska North Slope is a promising area for discovery of additional reserves to increase our domestic production of oil and natural gas. Currently, state lands on Alaska's North Slope provide about 17 percent of U.S. oil production. Oil and gas development in the Arctic, however, needs to be done in an environmentally responsible manner, using new technology and relying upon the best available scientific information. Such technology is making it possible to explore and develop oil and gas with significantly less impact on the environment. Areas with potential for oil and gas development are the National Petroleum Reserve-Alaska (NPR-A), the Arctic Outer Continental Shelf, and the Arctic National Wildlife Refuge (ANWR).

National Petroleum Reserve–Alaska

The National Petroleum Reserve–Alaska lies between the Brooks Range and the Arctic Ocean. The U.S. Geological Survey (USGS) estimates a high potential for oil and gas resources in the NPR–A, with a mean estimate of 2.1 billion barrels of oil and 8.5 trillion cubic feet of gas. A leasing program was designed and initiated in 1999 for the northeast sector of NPR–A, resulting in the award of 133 leases covering 900,000 acres. Eight exploratory wells have been completed in the past two years, and additional exploratory wells are expected this coming winter.

Recommendation:

★ The NEPD Group recommends that the President direct the Secretary of the Interior to consider additional environmentally responsible oil and gas development, based on sound science and the best available technology, through further lease sales in the National Petroleum Reserve–Alaska. Such consideration should include areas not currently leased within the Northeast corner of the Reserve.

Arctic National Wildlife Refuge

The Alaska National Interest Lands Conservation Act expanded ANWR from 9 million acres to 19 million acres, and designated 8 million acres as wilderness. Congress specifically left open the question of management of a 1.5-million-acre Arctic Coastal Plain area of ANWR because of the likelihood that it contains significant oil and gas resources. Section 1002 of the Act directed the Department of the Interior to conduct geological and biological studies of the Arctic Coastal Plain, “the 1002 Area,” and to provide to Congress the results of those studies with recommendations on future management of the area. Section 1003 of the Act prohibits leasing of the 1002 Area until authorized by an act of Congress.

In 1987, after more than five years of biological baseline studies, surface geological studies, and two seasons of seismic ex-

ploration surveys, the Department of the Interior recommended to Congress that the 1002 Area be leased for oil and gas exploration and production in an environmentally sensitive manner. In 1995, both the Senate and the House passed legislation containing a provision to authorize leasing in the 1002 Area, but the legislation was vetoed.

In May 1998, the USGS issued revised estimates of oil and gas resources in the 1002 Area. The 1998 USGS assessment shows an overall increase in estimated oil resources when compared to all previous government estimates. The estimate reaffirms the 1002 Area’s potential as the single most promising prospect in the United States. The total quantity of recoverable oil within the entire assessment area is estimated to be between 5.7 and 16 billion barrels (95 percent and 5 percent probability range) with a mean value of 10.4 billion barrels. The mean estimate of 10.4 billion barrels is just below the amount produced to date from North America’s largest field, Prudhoe Bay, since production began 23 years ago. Peak production from ANWR could to be between 1 and 1.3 million barrels a day and account for more than 20 percent of all U.S. oil production. ANWR production could equal 46 years of current oil imports from Iraq.

Technological improvements over the past 40 years have dramatically reduced industry’s footprint on the tundra, minimized waste produced, and protected the land for resident and migratory wildlife. These advances include the use of ice roads and drilling pads, low-impact exploration approaches such as winter-only exploration activities, and extended reach and through-tubing rotary drilling. These technologies have significantly reduced the size of production-related facilities on the North Slope. Estimates indicate that no more than 2,000 acres will be disturbed if the 1002 Area of ANWR is developed. For purposes of comparison, ANWR is about the size of the state of South Carolina, whereas the developed area is estimated to be less than one-fifth the size of Washington D.C.’s Dulles International Airport.

Recommendation:

★ The NEPD Group recommends that the President direct the Secretary of the Interior to work with Congress to authorize exploration and, if resources are discovered, development of the 1002 Area of ANWR. Congress should require the use of the best available technology and should require that activities will result in no significant adverse impact to the surrounding environment.

Other Onshore Restrictions

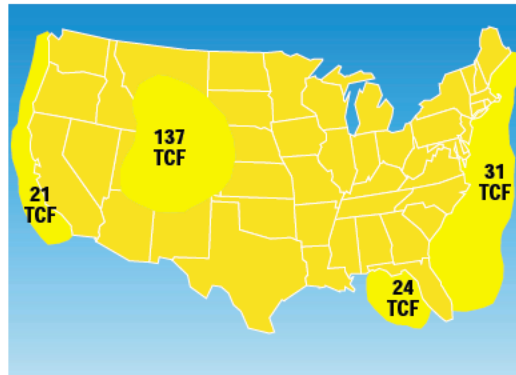
There is a significant potential for oil and gas resources on federal land in the lower 48 states as well. According to the most recent estimates from the USGS and the Minerals Management Service, oil resources underlying federal lands in the lower 48 states are estimated to be 4.1 billion barrels, and natural gas reserves are estimated to be 167 trillion cubic feet (Figure 5-4). Much of these potential resources have been placed off-limits or are subject to significant restrictions. For example, about 40 percent of the natural gas resources on federal land in the Rocky Mountain region have been placed off-limits.

The Department of the Interior initiated a study to examine the energy potential and restrictions on development on federal lands in the lower 48 states. In many cases, limits on oil and gas development are appropriate. However, improved technology has helped to reduce the impact of oil and gas development on the environment.

Exploration and Production

To meet increased natural gas demand in the coming decades, total wells drilled annually will need to double the 1999 level by 2020. Very few new onshore rigs have been built since the mid-1980s, because the oil field supply and service sectors have been hit especially hard by price volatility. Major additions to the offshore rig fleet will also be needed just to develop existing leases. The lack of an experienced work force may limit the speed and increase the cost of exploration and production activity.

Figure 5-4
**Restricted Natural Gas Resource Areas
in the U.S. Lower 48**



Much of the nation's oil and gas resource base resides on federal lands or in federal waters. A large portion of this is not open to exploration and development. For example, an estimated 40 percent or 137 trillion cubic feet of potential natural gas resource in the Rockies is either closed to exploration (29 tcf) or is open to development under restrictive provisions (108 tcf).

Source: U.S. Department of Energy, Energy Information Administration.

Electricity

Electricity is an essential part of modern life. When supply fails to keep pace with demand, costs to consumers and businesses rise and reliability falls. The California experience demonstrates the crippling effect that electricity shortages and blackouts can have on a state or region. This summer, the possibility exists for more intense electricity shortfalls in the West, with additional problems possible in New York City and on Long Island.

Electricity demand is projected to grow sharply over the next twenty years. Based on current estimates, the United States will need about 393,000 MW of new generating capacity by 2020 to meet the growing demand. If the U.S. electricity demand continues to grow at the high rate it has recently, we will need even more generating capacity. To meet that future demand, the United States will have to build between 1,300 to 1,900 new power plants; that averages out to be more than 60 to 90 plants a year, or more than one a week.

Over the next few years, if the demand for electricity continues to grow as predicted, and if we fail to implement a

comprehensive energy plan that recognizes the need to increase capacity, we can expect our electricity shortage problems to grow. The result will be higher costs and lower reliability.

Electricity Restructuring

One of the most important energy issues facing the Administration and Congress is electricity restructuring. The electricity industry is going through a period of dramatic change. To provide ample electricity supplies at reasonable prices, states are opening their retail markets to competition. This is the most recent step in a long transition from reliance on regulation to reliance on competitive forces.

Changes in Wholesale Electricity Market

This transition from regulation to competition began in 1978 with enactment of the Public Utility Regulatory Policies Act, which promoted independent electricity generation. Open-access transmission policies adopted by the Federal Energy Regulatory Commission (FERC) in the late 1980s further promoted competition in wholesale power markets. Congress largely ratified these policies with enactment of

the Energy Policy Act of 1992, which further promoted non-utility generation. FERC took another large step to promote competition with its open-access rule in 1996, which provided greater access to the transmission grid, the highway for interstate commerce in electricity.

Changes in the Retail Electricity Market

Increased competition in wholesale power markets encourages states to open retail electricity markets. Under current law, FERC has jurisdiction over the wholesale power market, while states have jurisdiction over retail markets. Beginning in 1996, states began opening their retail markets to competition in order to lower electricity prices. Twenty-five states have opted to open their retail electricity markets to competition.

Most new electricity generation is being built not by regulated utilities, but by independent power producers. These companies assume the financial risk of investment in new generation, and their success rides on their ability to generate electricity at a low cost.

These dramatic changes affecting the industry led to important structural changes. Independent power producers, which were once infant industries, now dwarf many utilities. Utility mergers, which were once rare, are now commonplace. U.S. utilities have been purchased by foreign companies, and U.S. utilities have in turn purchased utilities abroad. While utilities had service areas that were limited to a single state or region, independent power producers are international companies that can build power plants across the globe. Many utilities that were once vertically integrated divested themselves of generation, either voluntarily or because of state law.

Pending Congressional Action

Since 1995, Congress has been grappling with electricity competition legislation. Initial efforts sought to require states to open their retail markets by a date certain. Subsequent efforts focused on promoting competition in electricity markets and complementing state retail competition plans. Under this

Electricity demand is projected to rise sharply over the next twenty years. If we fail to build the 1,300–1,900 new power plants needed to increase generation and transmission capacity, current electricity shortages will become more frequent and more widespread.

U.S. DEPARTMENT OF ENERGY



approach, federal legislation focused on core federal issues, including:

- regulation of interstate commerce;
- assuring open access to the interstate and international transmission system;
- enhancing reliability of the grid;
- lowering barriers to entry;
- reforming outdated federal electricity laws, such as the Public Utility Holding Company Act and Public Utility Regulatory Policies Act of 1978;
- reforming the role of federal electric utilities in competitive markets;
- protecting consumers; and
- clarifying federal and state regulatory jurisdictions.

Recommendations:

★ The NEPD Group recommends that the President direct the Secretary of Energy to propose comprehensive electricity legislation that promotes competition, protects consumers, enhances reliability, improves efficiency, promotes renewable energy, repeals the Public Utility Holding Company Act, and reforms the Public Utility Regulatory Policies Act.

★ The NEPD Group recommends the President encourage FERC to use its existing statutory authority to promote competition and encourage investment in transmission facilities.

California Electricity Crisis

The California electricity crisis is not a test of the merits of competition in electricity markets. Instead, it demonstrates that a poorly designed state retail competition plan can have disastrous results if electricity supply does not keep pace with increased demand. At heart, the California electricity crisis is a supply crisis. California allowed demand to outstrip supply, and did little to lower barriers to entry through reform of an inflexible siting process. The risk that the California experience will repeat itself is low, since other states have not modeled their retail competition plans on California's plan.

The California crisis also shows that state electricity markets do not stay neatly confined within legal and jurisdictional bounds. Due to regional interconnection, disastrous mistakes made by the State of California have dire effects on the entire West. California's failure to reform flawed regulatory rules affecting the market drove up wholesale prices. Actions such as forcing utilities to purchase all their power through volatile spot markets, imposing a single-price auction system, and barring bilateral contracts all contributed to the problems that California now faces.

Lessons Learned from Successful Deregulation

As stated previously, 25 states have decided to open their retail electricity markets. A comparison of the different approaches taken by California and other states demonstrates that competition will benefit consumers if implemented effectively. A better gauge of the potential for retail competition to lower prices can be found in Pennsylvania, where electricity prices have fallen significantly as a result of competition. There is also reason to believe that the plan in Texas will have similar success.

A major difference between the California experience and the approaches taken by Pennsylvania and Texas is that the latter states ensured they had adequate electricity supplies. Pennsylvania and Texas took steps to ensure that procedures for adding new power plants were efficient. Unlike California, which imports 25 percent of its electricity, Pennsylvania is a net exporter of power, and Texas imports almost no power from other states. For these reasons, Pennsylvania and Texas have ample electricity supply to meet demand, while California is confronting a serious supply shortage.

In addition, California required its utilities to divest themselves of much of their generation, unlike Pennsylvania and Texas. This action forced California utilities to rely much more heavily on buying power, at ever-increasing prices, instead of generating power themselves.

Another major difference is that Pennsylvania and Texas did not require their utilities to purchase electricity through volatile spot markets. This requirement, combined with frozen retail rates imposed by the State, forced California utilities to purchase power at much higher costs than could be passed along to the consumer. As a result, the California regulatory plan resulted in unreliable service, destroyed the financial health of the State's utilities, and drove one utility into bankruptcy.

The federal government does not site power plants; that is a responsibility of the states. For that reason, delays relating to the construction of new power plants are usually the result of state action. A number of federal agencies, such as the Environmental Protection Agency, the Department of Commerce, and the Department of the Interior, do issue air and other permits for generation facilities. Some of the concerns about permitting or review delays in other states can be similarly addressed by expediting processes. These agencies, pursuant to President Bush's Executive Order, have expedited permit-processing applications for energy production in California.

Some of the concerns about permitting or review delays in other states can be similarly addressed by expediting processes. For example, in 1999–2000, the time for issuing air permits (including the time for public participation) for turbines was reduced to three to four months (compared to the twelve months allowed by the regulations) for the majority of permit applications.

Fuels for Electricity Generation

Electricity is not a primary source of energy. It is generated by the use of primary energy sources (Figure 5-5). Coal, nuclear energy, natural gas and hydropower account for about 95 percent of total electricity generation, with oil and renewable energy contributing the remainder. Despite this healthy diversity of energy sources, each type of electricity resource is faced with constraints to maintaining or expanding its contribution to electricity production.

Coal

Coal is used almost exclusively to generate electricity. Coal power plants account for over 50 percent of all U.S. electricity generation, and over 80 percent of generation in twelve states in the Midwest, Southeast, and West. Coal electricity generation costs are low, and coal prices have proved remarkably stable. In 1999, the United States produced 1.1 billion tons of coal. Production of coal from federal and tribal lands, which has increased substantially in the past decade, accounted for 38 percent of this total.

Although coal is the nation's most abundant fossil energy source, production and market issues can affect the adequacy of supply. Production issues include the protection of public health, safety, property, and the environment, and the effectiveness of federal and state agencies implementing various laws governing coal mining. These issues have resulted in some coal resources becoming uneconomical to produce. Statutory, regulatory, and administrative difficulties also may limit or prevent the production of some coal resources. However, technological advances in cleaner coal technology have allowed for significant progress toward reducing these barriers. There are also opportunities to protect the environment while lowering costs through further improvements in technology.

Over the past decade, greater efficiencies, lower capital costs, fewer emissions and quicker start-up times have made power plants fueled by natural gas a more attractive choice for new coal generation. Recently, however, rising natural gas prices have renewed interest in building coal power plants.

Uncertainty about future environmental controls is of particular concern for companies that operate existing coal power plants. Regulations under development include a variety of measures requiring reductions in emissions of nitrogen oxide, sulfur dioxide, and mercury. In addition, rules related to discharges to streams and cooling-water intake structures, possible regulation of large-volume wastes as hazardous wastes,

uncertainty over rules requiring air permits for certain modifications to power plants, and uncertainty over global and domestic efforts to reduce carbon dioxide emissions also play a role. This regulatory uncertainty discourages power producers from building coal power plants and is one reason the United States is relying so heavily on natural gas power generation to meet growing electricity demand.

Much of the current uncertainty has resulted because regulators do not weigh the cumulative impacts of their proposals. Compliance decisions by businesses concerning each new regulation must often be made without the benefit of clear information regarding additional requirements that may be imposed. More effective and economical compliance strategies are possible if companies know the full range of requirements with which they must comply.

If rising U.S. electricity demand is to be met, then coal must play a significant role. Under current policies, in the next two decades, nuclear electricity generation and hydropower are projected to decline. Natural gas electricity generation is projected to increase from about 16 to 36 percent of total generation, which would require the tripling of natural gas used for electricity generation. Significantly, this projected increase in natural gas genera-

tion assumes that coal electricity generation will continue to account for about 50 percent of U.S. electricity generation. If policies are adopted that sharply lower coal electricity generation, then the likely result is an even greater dependence on natural gas generation. This creates concern about the adequacy of natural gas supplies and policies.

Clean Coal Technology

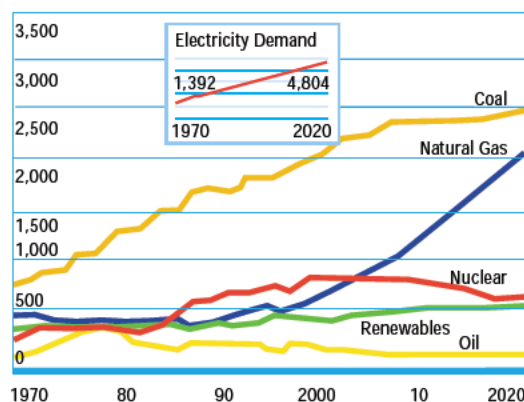
Technology has been and will continue to be a key to achieving our energy, economic, and environmental goals. In recent years, technological advancements through efforts of both the public and private sectors have led to substantial reductions in the cost of controlling sulfur dioxide and nitrogen oxide emissions, while the effectiveness of control systems increased significantly. The Department of Energy, through its Clean Coal Technology Program, has worked to provide effective control technologies. These nitrogen oxide and sulfur dioxide control technologies have moved into the utility marketplace and now provide a means to achieve cost effective regulatory compliance.

For example, most power plants that can use low nitrogen oxide burners have now installed them, and about 25 percent of all coal power plants have either ordered or installed selective catalytic reduction technology, which reduces nitrogen oxide emissions.

Technologies like fluidized-bed combustion and integrated gasification combined cycle have been developed that further reduce emissions. Fluidized-bed combustion is a low-emitting nitrogen oxide combustion technology that allows the use of fuels, such as coal pile washer waste, that were not formerly usable. Integrated gasification combined cycle is a relatively new technology that uses refinery waste as fuel.

Future coal electricity generation will need to meet new challenges to reduce emissions even further, especially mercury emissions. The Department of Energy is supporting efforts to develop more cost effective control technology. Indeed, the goal

Figure 5-5
Electricity Generation by Fuel: Current Trends
(Billions of Kilowatt-Hours)



Source: U.S. Department of Energy, Energy Information Administration

Clean Coal Technology

Clean Coal Technology describes a category of technologies that allow for the use of coal to generate electricity while meeting environmental regulations at low cost.

- In the short term, the goal of the program is to meet existing and emerging environmental regulations, which will dramatically reduce compliance costs for controlled mercury, NO_x, SO₂, and fine particulate at new and existing coal power plants.

- In the mid-term, the goal of the program is to develop low-cost, super-clean coal power plants, with efficiencies 50 percent higher than today's average. The higher efficiencies will reduce emissions at minimal costs.

- In the long term, the goal of the program is to develop low-cost, zero-emission power plants with efficiencies close to double that of today's fleet.

of these research, development, and demonstration programs is to develop and demonstrate coal power systems with near zero environmental emissions, while maintaining low production costs.

Recommendations:

- ★ The NEPD Group recognizes the importance of looking to technology to help us meet the goals of increasing electricity generation while protecting our environment. To that end, the NEPD Group recommends that the President direct the Department of Energy to continue to develop advanced clean coal technology by:

- Investing \$2 billion over 10 years to fund research in clean coal technologies.
- Supporting a permanent extension of the existing R&D tax credit.
- Directing agencies to explore regulatory approaches that will encourage advancements in environmental technology.

- ★ The NEPD Group recommends that the President direct federal agencies to provide greater regulatory certainty relating to coal electricity generation through clear policies that are easily applied to business decisions.

Nuclear Energy

Nuclear energy accounts for 20 percent of all U.S. electricity generation, and more than 40 percent of the electricity generation in ten states in the Northeast, the South, and the Midwest. Despite the closure of several less efficient plants during the 1990s, the 103 U.S. nuclear energy plants currently operating produce more electricity today than at any time in history.

There are a number of reasons why nuclear energy expansion halted in the 1980s. Regulatory changes implemented after the Three Mile Island incident in 1979 lengthened the licensing period to an average of fourteen years, resulting in large cost overruns. Increased public concern

about the safety of nuclear energy after the accident often resulted in active opposition to proposed plants. As a result, the last completed nuclear energy plant in the United States was ordered in 1973.

Since the 1980s, the performance of nuclear energy plant operations has substantially improved. While U.S. nuclear energy plants once generated electricity only around 70 percent of the time, the average plant today is generating electricity close to 90 percent. This improved performance has lowered the cost of nuclear generation, which is now competitive with other sources of electricity (Figure 5-6).

There is potential for even greater generation from existing nuclear energy plants. Experts estimate that 2,000 MW could be added from existing nuclear power plants by increasing operating performance to 92 percent. In addition, about 12,000 MW of additional nuclear electricity generation could be derived from uprating U.S. nuclear power plants, a process that uses new technologies and methods to increase rated power levels without decreasing safety. However, modifications to uprate plants can be expensive and require extensive licensing review and approval by the Nuclear Regulatory Commission (NRC). Another way to increase nuclear generation from existing plants is through license renewal. Many nuclear utilities are planning to extend the operating license of existing nuclear plants by twenty years, and the licenses of as many as 90 percent of the currently operating nuclear plants may be renewed.

The nuclear energy industry is closely regulated by the NRC, which provides rigorous oversight of the operation and maintenance of these plants. This oversight includes a comprehensive inspection program that focuses on the most significant potential risks of plant operations and features full-time resident inspectors at each plant, as well as regional inspectors with specialized expertise. The NRC has made great strides to provide greater regulatory certainty while maintaining high safety standards.

The installation of new design features, improvements in operating experience, nuclear safety research, and operator training have all contributed to the strong safety record of the nuclear energy industry. Since the Three Mile Island incident in 1979, the nuclear industry's safety record has significantly improved. This safety record has been achieved through a defense-in-depth philosophy accomplished by way of engineering design, quality construction, safe operation, and emergency planning. This philosophy provides for diverse and redundant systems to prevent accidents from occurring, as well as multiple safety barriers to mitigate the effects of accidents in the highly unlikely event they do occur.

Over the last several years, utilities have begun purchasing nuclear plants from other operators as the industry undergoes consolidation. Several nuclear utilities have merged, creating management teams with extensive expertise in running and maintaining nuclear plants. These mergers are impeded by tax rules relating to the transfer of decommissioning funds.

Utilities are also considering nuclear energy as an option for new generation. The NRC

has certified three standardized nuclear power plant designs, and Congress enacted legislation in 1992 to reform the nuclear licensing process. Under this process, a utility can apply for a combined construction and operating license for one of these standardized designs in a streamlined process. This reformed licensing process provides for site permits—a way to resolve siting issues early in the process. Building new generators on existing sites avoids many complex issues associated with building plants on new sites. Many U.S. nuclear plant sites were designed to host four to six reactors, and most operate only two or three; many sites across the country could host additional plants.

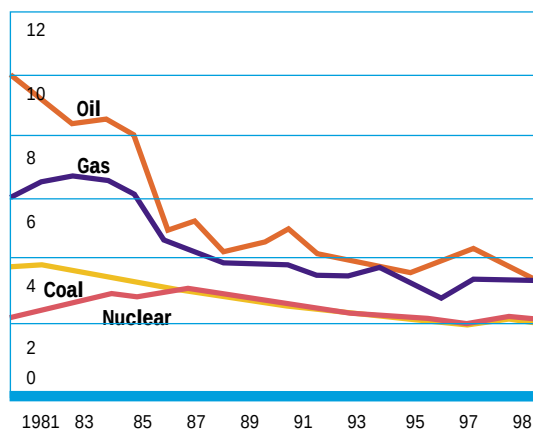
Advanced reactor technology promises to improve nuclear safety. One example of an advanced reactor design is the gas-cooled, pebble-bed reactor, which has inherent safety features. The industry has an interest in this and other advanced reactor designs.

The federal government must also provide for the safe disposal of nuclear waste. At present, nuclear waste continues to be stored at local plant sites. The Department of Energy is over a decade behind schedule for accepting nuclear waste from utilities, but has made progress toward characterization of the Yucca Mountain, Nevada site. Construction of an exploratory studies facility has been completed, a viability assessment was published, and recently scientists placed their extensive research about Yucca Mountain on the record for public scrutiny. However, key regulatory standards to protect public health and the environment at the repository have not been issued.

The Administration will continue to study the science to determine whether to proceed with the consideration of this site as the location for the repository. If the Administration decides to proceed, the Department of Energy must file a license application with the NRC. No waste will be sent to any location until the NRC determines it to be safe.

Other countries have developed different approaches for nuclear waste disposal. For example, the French, British and Japanese rely on reprocessing, an in-

Figure 5-6
Nuclear Generation is Competitively Priced
(1998 Cents per Kilowatt-Hour)



Note: Fuel costs are included.

Source: Utility Data Institute via the Nuclear Energy Institute.



Calvert Cliffs is the first U.S. nuclear plant to receive a renewed license from the Nuclear Regulatory Commission. The renewal will allow the plant to continue producing environmentally sound electricity for an additional twenty years.

CONSTELLATION ENERGY GROUP

dustrial approach that separates nuclear waste into usable fuel and highly concentrated waste. While this approach does not obviate the need for geologic disposal of nuclear waste, it could significantly optimize the use of a geologic repository. There is growing interest in new technology known as accelerator transmutation, which could be used in combination with reprocessing to reduce the quantity and toxicity of nuclear waste.

Recommendations:

★ The NEPD Group recommends that the President support the expansion of nuclear energy in the United States as a major component of our national energy policy. Following are specific components of the recommendation:

- Encourage the Nuclear Regulatory Commission (NRC) to ensure that safety and environmental protection are high priorities as they prepare to evaluate and expedite applications for licensing new advanced-technology nuclear reactors.
- Encourage the NRC to facilitate efforts by utilities to expand nuclear energy generation in the United States by uprating existing nuclear plants safely.

- Encourage the NRC to relicense existing nuclear plants that meet or exceed safety standards.
- Direct the Secretary of Energy and the Administrator of the Environmental Protection Agency to assess the potential of nuclear energy to improve air quality.
- Increase resources as necessary for nuclear safety enforcement in light of the potential increase in generation.
- Use the best science to provide a deep geologic repository for nuclear waste.
- Support legislation clarifying that qualified funds set aside by plant owners for eventual decommissioning will not be taxed as part of the transaction.
- Support legislation to extend the Price–Anderson Act.

★ The NEPD Group recommends that, in the context of developing advanced nuclear fuel cycles and next generation technologies for nuclear energy, the United States should reexamine its policies to allow for research, development and deployment of fuel conditioning methods (such as pyroprocessing) that reduce waste streams and enhance proliferation resistance. In doing so, the United States will continue to discourage the accumulation of separated plutonium, worldwide.

★ The United States should also consider technologies, in collaboration with international partners with highly developed fuel cycles and a record of close cooperation, to develop reprocessing and fuel treatment technologies that are cleaner, more efficient, less waste-intensive, and more proliferation-resistant.

Hydropower

Although hydropower generation accounts for only about 7 percent of overall U.S. electricity generation, the following states depend heavily on this source of energy: Idaho, Washington, Oregon, Maine, South Dakota, California, Montana, and New York.

Hydropower generation has remained relatively flat for years. The most significant constraint on expansion of U.S. hydropower generation is physical; most of the best locations for hydropower generation have already been developed. Potential does remain for some increases in hydropower generation, and capacity can be optimized by adding additional turbines and increasing efficiency at existing facilities.

Also, the amount of hydropower generation depends upon the quantity of available water. A drought can have a devastating effect on a region that depends on hydropower. In fact, this year's water availability has been a contributing factor in California's electricity supply shortages. The amount of hydropower generation depends upon the quantity of available water. A drought can have a devastating effect on a region that depends on hydropower. In fact, this year's water availability has been a contributing factor in California's electricity supply shortages.

The Federal Energy Regulatory Commission is required to incorporate mandatory conditions proposed by different state and federal resource agencies into hydropower licenses. Decision-making authority in the licensing process is diffused among a host of federal and state agencies, all of which are pursuing different statutory missions. The hydropower licensing process is prolonged, costly, and poses regulatory uncertainty. The challenge is to efficiently and effectively balance national interests in natural resource and environmental preservation with energy needs.

Recommendation:

★ The NEPD Group recognizes there is a need to reduce the time and cost of the hydropower licensing process. The NEPD Group recommends that the President encourage the Federal Energy Regulatory Commission (FERC) and direct federal resource agencies to make the licensing process more clear and efficient, while preserving environmental goals. In addition, the NEPD Group recognizes the importance of optimizing the efficiency and reliability of existing hydropower facilities, and will encourage the Administration to adopt efforts toward that end.

- Support administrative and legislative reform of the hydropower licensing process.
- Direct federal resource agencies to reach interagency agreement on conflicting mandatory license conditions before they submit their conditions to FERC for inclusion in a license.
- Encourage FERC to adopt appropriate deadlines for its own actions during the licensing process.

Natural Gas

Currently, natural gas provides about 16 percent of U.S. electricity generation. Seven states obtain over one-third of their generation from natural gas (Rhode Island, New York, Delaware, Louisiana, Texas, California, and Alaska). Perhaps more importantly, natural gas-fired electricity is projected to constitute about 90 percent of capacity additions between 1999 and 2020. The amount of natural gas used in electricity generation is projected to triple by 2020.

Ensuring the long-term availability of adequate, reasonably priced natural gas supplies is a challenge. Low gas prices in 1998 and 1999 caused the industry to scale back gas exploration and production activity. Since 2000, the North American natural gas market has remained tight due to strong demand and diminished supplies. Last year, natural gas prices quadrupled, which resulted in substantially higher prices for electricity generated with natural gas.

While the largest barriers to expanded natural gas electricity generation relate to production and pipeline constraints, there are several other barriers. Environmental regulations affect the use of gas for electricity generation. Although natural gas electric plants produce fewer emissions than coal-fired power plants, they still emit nitrogen oxides, carbon dioxide and small amounts of toxic air emissions.'

Oil

While oil fuels only about 3 percent of total U.S. electricity generation, it is the dominant source of electricity generation in Hawaii, and provides over 20 percent of the generation in Massachusetts, Connecticut, Delaware, Maine, and Florida. Over the next twenty years, market conditions are expected to reduce today's level of oil electricity generation by about 80 percent.

Renewable Energy

Hydropower is, to date, the most successful form of renewable energy. However, some forms of renewable energy generation—wind, geothermal, and biomass—have the potential to make more significant contributions in coming years, and the cost of most forms of renewable energy has declined sharply in recent years. The most important barrier to increased renewable energy production remains economic; nonhydropower renewable energy generation costs are greater than other traditional energy sources. The following chapter discusses renewable and alternative energy in greater detail.

High-tech power plants, like this combined cycle plant, are signaling a new age in electric power generation. The capability to co-produce electricity and a slate of fuels and chemicals makes the technology economically attractive to a broad range of industrial applications.

TAMPA ELECTRIC COMPANY



Summary of Recommendations

Energy for a New Century: Increasing Domestic Energy Supplies

- ★ The NEPD Group recommends that the President direct the Secretaries of Energy and the Interior to promote enhanced oil and gas recovery from existing wells through new technology.
- ★ The NEPD Group recommends that the President direct the Secretary of Energy to improve oil and gas exploration technology through continued partnership with public and private entities.
- ★ The NEPD Group recommends that the President direct the Secretary of the Interior to examine land status and lease stipulation impediments to federal oil and gas leasing, and review and modify those where opportunities exist (consistent with the law, good environmental practice, and balanced use of other resources).
 - Expedite the ongoing Energy Policy and Conservation Act study of impediments to federal oil and gas exploration and development.
 - Review public lands withdrawals and lease stipulations, with full public consultation, especially with the people in the region, to consider modifications where appropriate.
- ★ The NEPD Group recommends that the President direct the Secretary of the Interior to consider economic incentives for environmentally sound offshore oil and gas development where warranted by specific circumstances: explore opportunities for royalty reductions, consistent with ensuring a fair return to the public where warranted for enhanced oil and gas recovery; for reduction of risk associated with production in frontier areas or deep gas formations; and for development of small fields that would otherwise be uneconomic.
- ★ The NEPD Group recommends that the President direct the Secretaries of Commerce and Interior to re-examine the current federal legal and policy regime (statutes, regulations, and Executive Orders) to determine if changes are needed regarding energy-related activities and the siting of energy facilities in the coastal zone and on the Outer Continental Shelf (OCS).
- ★ The NEPD Group recommends that the President direct the Secretary of the Interior continue OCS oil and gas leasing and approval of exploration and development plans on predictable schedules.
- ★ The NEPD Group recommends that the President direct the Secretary of the Interior to consider additional environmentally responsible oil and gas development, based on sound science and the best available technology, through further lease sales in the National Petroleum Reserve-Alaska. Such consideration should include areas not currently leased within the Northeast corner of the Reserve.
- ★ The NEPD Group recommends that the President direct the Secretary of the Interior work with Congress to authorize exploration and, if resources are discovered, development of the 1002 Area of ANWR. Congress should require the use of the best available technology and should require that activities will result in no significant adverse impact to the surrounding environment.

★ The NEPD Group recommends that the President direct the Secretary of the Interior to work with Congress and the State of Alaska to put in place the most expeditious process for renewal of the Trans-Alaska Pipeline System rights-of-way to ensure that Alaskan oil continues to flow uninterrupted to the West Coast of the United States.

★ The NEPD Group recommends that the President direct the Secretary of Energy to propose comprehensive electricity legislation that promotes competition, protects consumers, enhances reliability, promotes renewable energy, improves efficiency repeals the Public Utility Holding Company Act, and reforms the Public Utility Regulatory Policies Act.

★ The NEPD Group recommends that the President encourage FERC to use its existing statutory authority to promote competition and encourage investment in transmission facilities.

★ The NEPD Group recognizes the importance of looking to technology to help us meet the goals of increasing electricity generation while protecting our environment. To that end, the NEPD Group recommends that the President direct the Department of Energy to continue to develop advanced clean coal technology by:

- Investing \$2 billion over 10 years to fund research in clean coal technologies.
- Supporting a permanent extension of the existing research and development tax credit.
- Directing federal agencies to explore regulatory approaches that will encourage advancements in environmental technology.

★ The NEPD Group recommends that the President direct federal agencies to provide greater regulatory certainty relating to coal electricity generation through clear policies that are easily applied to business decisions.

★ The NEPD Group recommends that the President support the expansion of nuclear energy in the United States as a major component of our national energy policy. Following are specific components of the recommendation:

- Encourage the Nuclear Regulatory Commission (NRC) to ensure that safety and environmental protection are high priorities as they prepare to evaluate and expedite applications for licensing new advanced-technology nuclear reactors.
- Encourage the NRC to facilitate efforts by utilities to expand nuclear energy generation in the United States by uprating existing nuclear plants safely.
- Encourage the NRC to relicense existing nuclear plants that meet or exceed safety standards.
- Direct the Secretary of Energy and the Administrator of the Environmental Protection Agency to assess the potential of nuclear energy to improve air quality.
- Increase resources as necessary for nuclear safety enforcement in light of the potential increase in generation.
- Use the best science to provide a deep geologic repository for nuclear waste.
- Support legislation clarifying that qualified funds set aside by plant owners for eventual decommissioning will not be taxed as part of the transaction.
- Support legislation to extend the Price–Anderson Act.

★ The NEPD Group recommends that, in the context of developing advanced nuclear fuel cycles and next generation technologies for nuclear energy, the United States should reexamine its policies to allow for research, development and deployment of fuel conditioning methods (such as pyroprocessing) that reduce waste streams and enhance proliferation resistance. In doing so, the United States will continue to discourage the accumulation of separated plutonium, worldwide.

★ The United States should also consider technologies (in collaboration with international partners with highly developed fuel cycles and a record of close cooperation) to develop reprocessing and fuel treatment technologies that are cleaner, more efficient, less waste-intensive, and more proliferation-resistant.

★ The NEPD Group recognizes there is a need to reduce the time and cost of the hydropower licensing process. The NEPD Group recommends that the President encourage the Federal Energy Regulatory Commission (FERC) and direct federal resource agencies to make the licensing process more clear and efficient, while preserving environmental goals. In addition, the NEPD Group recognizes the importance of optimizing the efficiency and reliability of existing hydropower facilities and will encourage the Administration to adopt efforts toward that end.

- Support administrative and legislative reform of the hydropower licensing process.
- Direct federal resource agencies to reach interagency agreement on conflicting mandatory license conditions before they submit their conditions to FERC for inclusion in a license.
- Encourage FERC to adopt appropriate deadlines for its own actions during the licensing process.

Nature's Power

Increasing America's Use of Renewable and Alternative Energy

A sound national energy policy should encourage a clean and diverse portfolio of domestic energy supplies. Such diversity helps to ensure that future generations of Americans will have access to the energy they need.

Renewable energy can help provide for our future needs by harnessing abundant, naturally occurring sources of energy, such as the sun, the wind, geothermal heat, and biomass. Effectively harnessing these renewable resources requires careful planning and advanced technology. Through improved technology, we can ensure that America will lead the world in the development of clean, natural, renewable and alternative energy supplies.

Renewable and alternative energy supplies not only help diversify our energy portfolio; they do so with few adverse envi-

ronmental impacts. While the current contribution of renewable and alternative energy resources to America's total electricity supply is relatively small—only 9 percent—the renewable and alternative energy sectors are among the fastest growing in the United States. Non-hydropower only account for 2 percent of our electricity needs. However, electricity generation from non-hydropower renewable energy grew by nearly 30 percent in the 1990s. Continued growth of renewable energy will continue to be important in delivering larger supplies of clean, domestic power for America's growing economy.

Renewable energy resources tap naturally occurring flows of energy to produce electricity, fuel, heat, or a combination of these energy types. One type of renewable energy, hydropower, has long provided a significant contribution to the U.S. energy supply and today is competitive with other forms of conventional electricity. However, there is limited growth potential for hydropower. Non-hydropower renewable energy is generated from four sources: biomass, geothermal, wind, and solar (Figure 6-1). The United States has significant potential for renewable resource development. These nondepletable sources of energy are domestically abundant and often have less impact on the environment than conventional sources. They can provide a reliable source of energy at a stable price, and they can also generate income for farmers, landowners, and others who harness them.

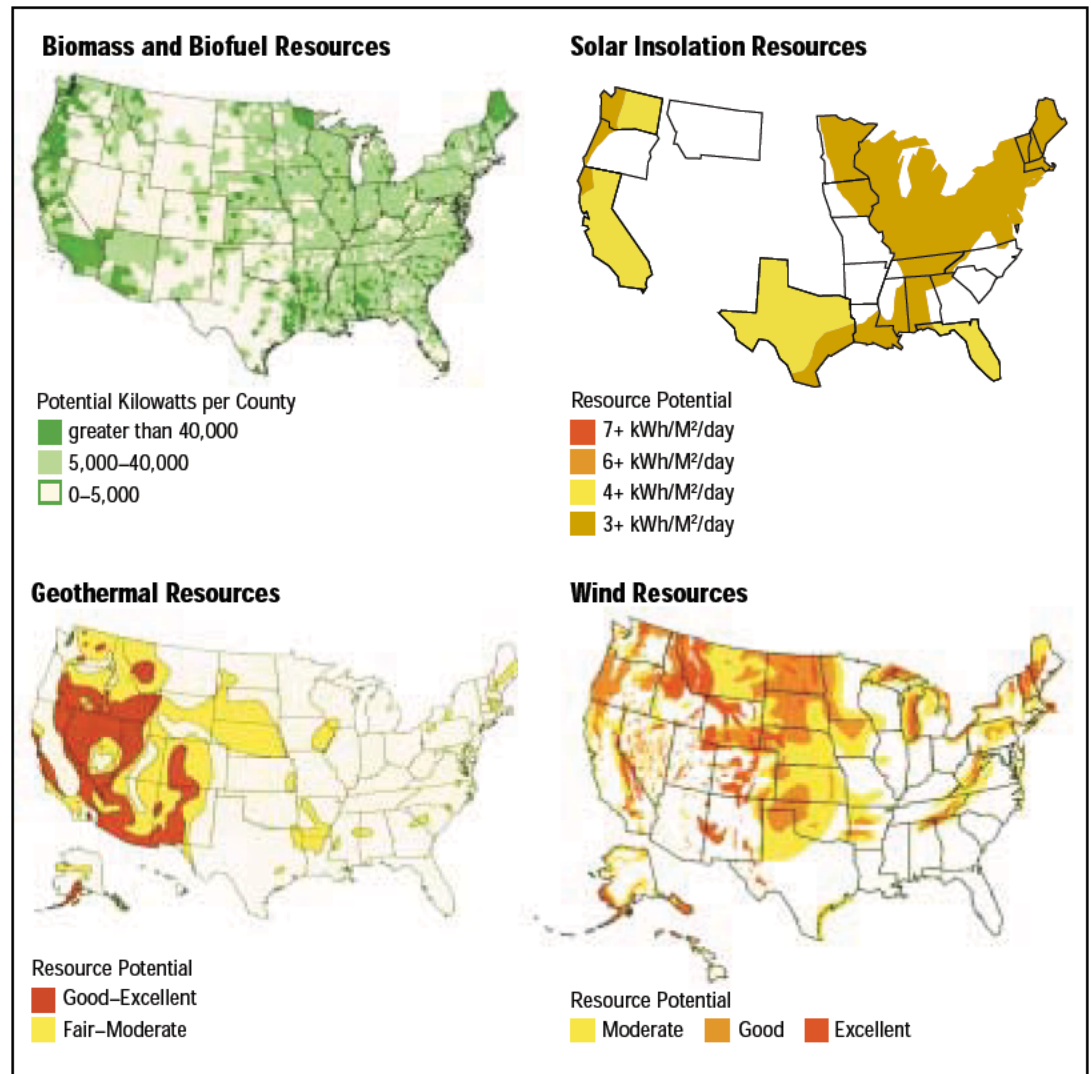
Renewable hydropower has long provided a significant contribution to the U.S. energy supply. Today, hydropower is competitive with other forms of conventionally generated electricity.





Figure 6-1

U.S. Resource Potential for Renewable Energy



Almost every state has the potential for wind energy and for biomass and biofuel production. The Southwest has the greatest potential for solar energy, and geothermal energy resources are most abundant in the West.

Source: U.S. Department of Energy, National Renewable Energy Laboratory.

Recommendation:

★ The NEPD Group recommends that the President direct the Secretaries of the Interior and Energy to re-evaluate access limitations to federal lands in order to increase renewable-energy production, such as biomass, wind, geothermal, and solar.

Alternative energy includes: alternative fuels that are transportation fuels other than gasoline and diesel, even when the

type of energy, such as natural gas, is traditional; the use of traditional energy sources, such as natural gas, in untraditional ways, such as for distributed energy at the point of use through microturbines or fuel cells; and future energy sources, such as hydrogen and fusion.

Both renewable and alternative energy resources can be produced centrally or on a distributed basis near their point of use. Providing electricity, light, heat, or mechanical energy at the point of use diminishes the

need for some transmission lines and pipe lines, reducing associated energy delivery losses and increasing energy efficiency. Distributed energy resources may be renewable resources, such as biomass cogeneration in the lumber and paper industry or rooftop solar photovoltaic systems on homes, or they may be alternative uses of traditional energy, such as natural gas microturbines.

Recommendations:

★ The NEPD Group supports the increase of \$39.2 million in the FY 2002 budget amendment for the Department of Energy's Energy Supply account that would provide increased support for research and development of renewable energy resources.

★ The NEPD Group recommends that the President direct the Secretary of Energy to conduct a review of current funding and historic performance of renewable energy and alternative energy research and development programs in light of the recommendations of this report. Based on this review, the Secretary of Energy is then directed to propose appropriate funding of those research and development programs that are performance-based and are modeled as public-private partnerships.

Renewable Energy Technologies

Biomass

Biomass is organic matter that can be used to provide heat, make fuel, and generate electricity. Wood, the largest source of biomass, has been used to provide heat for thousands of years. Many other types of biomass are also used as an energy source, such as plants, residue from agriculture or forestry, and the organic component of municipal and industrial wastes. Landfill gas is also considered a biomass source. Biomass resources can be replenished through culti-

Microturbines

Microturbines are small combustion turbines approximately the size of a refrigerator with outputs of 25 to 500 kilowatts. Microturbines can be used to power a home or small business. This technology has evolved largely from automotive and truck turbochargers, auxiliary power units for airplanes, and small jet engines.

Compared to other technologies for small-scale power generation, microturbines offer a number of significant advantages, including a small number of moving parts; compact size; lightweight, optimal efficiency; lower emissions and electricity costs; and opportunities to use waste fuels. For these reasons, microturbines could easily capture a significant share of the distributed generation market.

vation of what are known as energy crops, such as fast-growing trees and grasses.

Unlike other renewable energy sources, biomass can be converted directly into liquid fuels, called biofuels, to meet our transportation needs. The two most common biofuels are ethanol and biodiesel.

Ethanol is made by fermenting any biomass that is rich in carbohydrates, such as corn. It is mostly used as a fuel additive to reduce a vehicle's emissions. Biodiesel is made using vegetable oils, animal fats, algae, or even recycled cooking greases. It can be used as a diesel additive to reduce emissions or in its pure form to fuel a vehicle. Beyond energy benefits, development of biomass benefits rural economies that produce crops used for biomass, particularly ethanol and biomass electricity generation.

Biomass, like corn, that is rich in carbohydrates can be converted directly into biofuels to meet our transportation needs. The biofuel ethanol is mostly used as a fuel additive to reduce vehicles' smog-causing emissions. In June 1992, the Greater Peoria Mass Transit District began operating fourteen ethanol-powered buses along regular city routes.

U.S. DEPARTMENT OF ENERGY



Biomass is also used to generate electricity. This is accomplished through the direct combustion of wood, municipal solid waste, and other organic materials; co-firing with coal in high efficiency boilers; or combustion of biomass that has been chemically converted into fuel oil. In the lumber and paper industries, wood scraps are sometimes directly fed into boilers to produce steam for their manufacturing processes or to heat their buildings. For that reason, renewable energy offers a particular advantage to the lumber and paper industry, and many analysts project the industry may soon become a net seller of electricity. Co-firing coal power plants with biomass has environmental benefits, since co-firing can significantly reduce emissions. Biomass accounts for 76 percent of renewable electricity generation and 1.6 percent of total U.S. electricity supply.

Even gas for generating electricity can be produced from biomass. Gasification systems use high temperatures to convert biomass into a gas that is used to fuel a turbine. The decay of biomass in landfills also produces methane, a gas that can be captured and burned in a boiler to produce steam for electricity generation or for industrial processes. Using methane emissions increases electricity supplies, reduces pollution from landfills and reduces greenhouse gas emissions. The technologies to collect and use landfill methane to generate electricity are already in the market. How-

ever, they have not been successfully integrated at present due to the perceived higher risk of new technologies.

Recommendation:

★ The NEPD Group recommends that the President direct the Secretary of the Treasury, to work with Congress on legislation to expand the section 29 tax credit to make it available for new landfill methane projects. The credit could be tiered, depending on whether a landfill is already required by federal law to collect and flare its methane emissions due to local air pollution concerns.

Geothermal

Geothermal energy is the use of steam and hot water generated by heat from the Earth to perform work. Some geothermal power plants use steam or hot water from a natural underground reservoir to power a generator. Others use hot water to provide direct heat for residential and other buildings, and for other applications.

The most readily accessible resources for geothermal power generation in the United States are located in the West, Alaska, and Hawaii. A wide array of high technology geological, geochemical, and geophysical techniques are used to locate geothermal resources. In large measure, the technology for developing these resources has been adapted from the oil industry. Improvements in drill bits, drilling techniques, advanced instruments, and other technological advances have made energy production from geothermal resources increasingly efficient.

Geothermal accounts for 17 percent of renewable electricity generation and 0.3 percent of total U.S. electricity supply. However, the net installed capacity of U.S. geothermal power plants has increased significantly, from 500 MW in 1973 to 2,800 MW today.

Hot water near the surface of the Earth can also be used directly for heat. These direct-use applications include heat

The Geysers in northern California is the world's largest producer of renewable geothermal power. The dry-steam field has successfully produced power since the early 1960s, when Pacific Gas & Electric installed the first 11-megawatt plant. Today, nearly 2,000 megawatts are on line – enough energy to supply the electricity needs of San Francisco and Oakland.

PACIFIC GAS & ELECTRIC



ing buildings, growing plants in green houses, drying crops, heating water at fish farms, and several industrial processes, such as pasteurizing milk.

In addition, individual homeowners, farmers, and businesses can tap into geothermal energy through geothermal heat pumps to heat and cool buildings. A geothermal heat pump system consists of a heat pump, an air delivery system, a heat exchanger, and a system of pipes buried in the shallow ground near the building. In the winter, a heat pump removes heat from the heat exchanger and pumps that heat into the indoor air delivery system. In the summer, the process is reversed, and the heat pump moves heat from the indoor air into the heat exchanger. The heat removed from the indoor air during the summer can also be used to provide a free source of hot water. Geothermal heat pumps can be used almost anywhere in the United States, and can significantly increase system efficiencies.

Recommendation:

★ The NEPD Group recommends that the President direct the Secretary of the Interior to determine ways to reduce the delays in geothermal lease processing as part of the permitting review process.

Wind Energy

Wind energy has been used since at least 200 B.C. for grinding grain and pumping water. By 1900, windmills were used on farms and ranches in the United States to pump water and, eventually, to produce electricity. Windmills developed into modern-day wind turbines.

Wind turbines are used for several applications. Wind power uses the naturally occurring energy of the wind for practical purposes like generating electricity, charging batteries, or pumping water. Large, modern wind turbines operate together in wind farms to produce electricity for utilities. Small turbines are used by homeowners, farmers, and remote villages to help meet localized energy needs.

Wind turbines capture energy by using propeller-like blades that are mounted on a



rotor. These blades are placed on top of high towers, in order to take advantage of the stronger winds at 100 feet or more above the ground. The wind causes the propellers to turn, which then turn the attached shaft to generate electricity. Wind can be used as a stand-alone source of energy or in conjunction with other renewable energy systems. Wind and natural gas hybrid systems are a promising approach that offers clean power to consumers.

Wind energy accounts for 6 percent of renewable electricity generation and 0.1 percent of total electricity supply. However, advances by research labs, universities, utilities, and wind energy developers have helped cut wind energy's costs by more than 80 percent during the last twenty years. The industry is poised for growth. In some parts of the country, electricity from wind power can be produced at prices that are comparable to other conventional energy technologies. The United States has many areas with abundant wind energy potential, namely in the West, the Great Plains and New England.

Solar

Sunlight, or solar energy, can be used to generate electricity; heat water; and heat, cool, and light buildings. Photovoltaic (solar cell) systems use semiconductor materials similar to those used in computer chips to capture the energy in sunlight and to convert it directly into electricity. Photovoltaic cells have been used in everything from

In 1996, the National Association of Home Builders constructed advanced townhouses featuring standing-seam roofs and other energy efficient materials and systems. The townhouse on the right differs from the others in that it has an integrated photovoltaic standing-seam roof that also produces electricity.

TIM ELLISON, ENERGY CONVERSION DEVICES

the solar cells in calculators to the space station Freedom.

Another technology for harnessing the sun's energy is a concentrating solar power system, which uses the sun's heat to generate electricity. The sunlight is collected and focused with mirrors to create a high intensity heat source that in turn can be used to generate electricity through a steam turbine or a heat engine.

Solar hot water systems use the sun to heat water for domestic or industrial use. Many large commercial buildings also use solar collectors for heat. A solar ventilation system can be used in cold climates to pre heat air as it enters a building. The heat from a solar collector can even be used to provide energy for cooling a building.

Some architects are using careful design and new optical materials to use sunlight to reduce the need for traditional lighting and to cut down on heating and cooling costs. For example, materials that absorb and store the sun's heat can be built into the sunlit floors and walls. The floors and walls

will store heat during the day and slowly release heat at night.

While solar energy technologies have undergone technological and cost improvements and are well established in high value markets like remote power, satellites, communications, and navigational aids, continued research is needed to reduce costs and improve performance. Solar energy accounts for 1 percent of renewable electricity generation and 0.02 percent of total U.S. electricity supply.

Alternative Energy

Alternative Transportation Fuels

Alternative fuels are any transportation fuels made from a nontraditional source, including ethanol, biodiesel, and other biofuels. These can be made from biomass resources, including liquid fuels (e.g., ethanol, methanol, biodiesel) and gaseous fuels (e.g., hydrogen and methane). Biofuels are primarily used to fuel vehicles, but can also fuel engines or fuel cells for electricity generation. Alternative fuels also

Recommendations:

- ★ The NEPD Group recommends that the President direct the Administrator of the Environmental Protection Agency to develop a new renewable energy partnership program to help companies more easily buy renewable energy, as well as receive recognition for the environmental benefits of their purchase, and help consumers by promoting consumer choice programs that increase their knowledge about the environmental benefits of purchasing renewable energy.
- ★ The NEPD Group recommends that the President direct the Secretary of the Treasury to work with Congress on legislation to extend and expand tax credits for electricity produced using renewable technology, such as wind and biomass. The President's budget request extends the present 1.7 cents per kilowatt hour tax credit for electricity produced from wind and biomass; expands eligible biomass sources to include forest-related sources, agricultural sources, and certain urban sources; and allows a credit for electricity produced from biomass co-fired with coal.
- ★ The NEPD Group recommends that the President direct the Secretary of the Treasury to work with Congress on legislation to provide a new 15 percent tax credit for residential solar energy property, up to a maximum credit of \$2,000.
- ★ The NEPD Group recommends that the President direct the Secretaries of the Interior and Energy to work with Congress on legislation to use an estimated \$1.2 billion of bid bonuses from the environmentally responsible leasing of ANWR for funding research into alternative and renewable energy resources, including wind, solar, geothermal, and biomass.

Alternative Fuel Vehicles

Alternative fuel vehicles (AFVs) can run on methanol, ethanol, compressed natural gas, liquefied natural gas, propane, hydrogen, electricity, biodiesel, and natural gas. Today, more than 450,000 alternative vehicles are operating in the United States. Some of the barriers to using AFVs include:

Cost—For example, a Ford Crown Victoria that runs on compressed natural gas costs about \$4,000 more than its gasoline counterpart.

Refueling Infrastructure—Refueling infrastructure is limited, which can make refueling inconvenient and travel options difficult.

Travel Distance—Ability to travel a long distance on a single volume of fuel. Alternative fuels have an energy content lower than that of gasoline, which means that AFVs cannot travel as far as traditional vehicles on a single tank of fuel.

In the short term, natural gas and propane offer the greatest potential for market growth, especially in niche markets where lower fuel costs make them attractive, such as transit buses, school buses, shuttles, and other heavy-duty vehicles. Ethanol vehicles offer tremendous potential if ethanol production can be expanded. Electric vehicles could reach large numbers in the future if technology breakthroughs help bring costs down and increase driving distance. Fuel cell vehicles operating on compressed hydrogen offer long-term potential. Compressed natural gas offers a distribution stepping-stone to a hydrogen-refueling infrastructure.

include traditional energy sources, such as natural gas and liquid propane that are traditionally not used as a transportation fuel.

Currently, there are approximately 450,000 alternative fuel vehicles in the United States, and more than 1.5 million flexible-fuel vehicles that can use gasoline or a mixture of ethanol and gasoline. Ethanol is made by converting the carbohydrate portion of biomass into sugar, which is then converted into ethanol through a fermentation process. Ethanol is the most widely used biofuel, and its production has increased sharply since 1980, rising from 200 million gallons a year to 1.9 billion gallons. Today, many states are considering phasing out the use of MTBE (methyl tertiary butyl ether), an oxygenate additive for gasoline. If they do so, that will likely spur greater reliance on ethanol.

Each year, approximately 65 percent of the oil consumed in the United States is used for transportation. As a result, vehicle emissions have become the leading source of U.S. air pollution. However, recent advances in fuels and vehicle design are helping increase fuel efficiency and reduce toxic substances discharged into the air.

Changes in the composition of trans

portation fuels, such as gasoline and diesel fuels, are one way to improve vehicle performance while reducing emissions and lowering oil consumption. Reformulated gasoline contains fuel additives such as ethanol to increase oxygen content, which reduces harmful emissions such as carbon monoxide. Low-sulfur gasoline reduces sulfur oxide emissions. New diesel fuels, some of which have lower sulfur contents or are produced from clean-burning natural gas, can help vehicles with diesel engines achieve lower emissions.

In addition to advanced transportation fuels, alternative fuels are being developed, such as biodiesel, electricity, ethanol, hydrogen, methanol, natural gas, and propane. These alternative fuels not only reduce dependence on petroleum transportation fuels. They reduce or entirely eliminate harmful emissions as well. With the exception of natural gas and propane, these fuels also have the potential of being generated from renewable resources, such as ethanol from corn. The federal government has promoted development of alternative fuels for many years and this program has helped to reduce U.S. reliance on oil-based fuels.

The evolution toward more efficient,

environmentally friendly transportation fuels has been mirrored by improvements in vehicle design, components, and materials. Alternative fuel vehicles, which can either switch between two fuels or run on a mixture of two fuels such as gasoline and ethanol, are now available. Recent developments in both alternative fuel vehicles and petroleum-based vehicles, such as advances in engines, drive trains, and emission-control technologies, may double or triple the efficiency of current vehicles. Some of these new technologies include hybrid electric vehicles, which combine an engine with an electric motor, and fuel cells, which produce electricity by converting a fuel, generally hydrogen and oxygen, into water.

A number of issues drive the research and marketability of advanced alternative fuel vehicles and petroleum-based vehicles in the United States. The goal of reducing U.S. dependence on imported oil, combined with the link between vehicle emissions and air pollution, have prompted the development of emissions and fuel economy standards for car manufacturers. In addition, federal, state, and local governments have enacted regulations, laws, and incentives designed to reduce the number of vehicle miles traveled and to encourage businesses and individuals to purchase alternative fuel vehicles.

The success of the federal alternative fuels program has been limited, however. The current program focuses on mandating certain fleet operators to purchase alternative fueled vehicles. The hope was that this vehicle purchase mandate would lead to expanded use of alternative fuels. That expectation has not been realized, since most fleet operators purchase dual-fueled vehicles that operate on petroleum motor fuels. The Clean Air Act required the use of oxygenates, such as MTBE (methyl tertiary butyl ether) and ethanol in fuel. These oxygenates account for 92 percent of alternative fuel use. Reforms to the federal alternative fuels program could promote alternative fuels use instead of mandating purchase of vehicles that ultimately run on petroleum fuels.

Recommendation:

★ The NEPD Group recommends that the President direct the Secretary of Treasury to work with Congress to continue the ethanol excise tax-exemption.-

Distributed Energy

Untapped opportunities for reducing energy demand loads could be realized by better integrating electricity supply systems and customers. Improved integration can produce a variety of benefits for tight energy markets, including reducing peak demand loads, bypassing congested areas of transmission by placing new generating capacity closer to the consumer, and thus achieving greater overall system efficiencies.

Current electricity load management efforts are typically limited to cutting off in interruptible or nonfirm customers, appeals to the public to conserve, and brownouts. Some utilities are incorporating current generation metering, sensor, and control technologies to take the next step: selective reduction of individual energy-using appliances. In some areas, residents can reduce their monthly bills by allowing the utility to electronically turn off selected appliances, such as water heaters, on a rotating basis. If this option is well managed, consumers are unaware of the temporary loss service, and critical systems continue to run unimpeded. Advanced integrated supply-and-demand load management controls also allow for widespread “demand auctions,” in which consumers can decide which energy services to forego on which days.

Distributed energy resources describe a variety of smaller electricity-generating options well suited for placement in homes, offices, and factories, or near these facilities. Distributed energy systems have the distinct advantage of being brought on line faster than new central power plants. While natural gas microturbines and solar roof panels are the most familiar types of distributed energy, other distributed energy resources include: combined heat and power, stationary fuel cells, generation of

bioenergy from landfill methane recovery, and small wind systems. Photovoltaic solar distributed energy is a particularly valuable energy generation source during times of peak use of power.

Efficiency gains from distributed energy come from three sources. First, transmission and distribution line losses (about 5 percent) are reduced because the energy is generally used near the source. Second, the co-location with consumption makes it more feasible to use waste heat, displacing otherwise needed natural gas or electricity for heating purposes. And, third, the co-location with consumption allows for the integration of on-site energy efficiency and generating capabilities. For example, in the residential market, distributed energy applications can make possible the concept of the “net zero energy home,” in which the overall level of energy produced at the home equals or exceeds the amount of energy used in the home.

Despite these advantages, a number of impediments and competing policy objectives discourage the wider application of integrated electricity supply and demand solutions, many of which reflect the relative newness and lack of familiarity with these technologies.

For example, the lack of standards governing interconnection of distributed energy to the grid impedes development. The lack of standards prevents a uniformly effective means of getting excess distributed energy to the grid.

In addition, current air quality regulations do not take into account the additional energy savings from many distributed energy technologies. Likewise, distributed energy systems purchased by consumers may receive different tax rates than those purchased by traditional electricity producers.

Although distributed energy can alleviate distribution constraints, these systems often cannot be sited and permitted in a timely manner. For instance, land-use zoning codes may not allow generating equipment in association with residential or commercial land uses, and building code officials may not know enough about solar roof systems to provide timely building permits.

As with energy efficiency equipment, load management integrating systems, both controls and distributed energy, have higher first costs associated with lower future energy bills.

Another barrier to development of distributed energy is the need for net metering, which enables consumers to install a small electricity project at their homes and sell the excess to the local utility, offsetting their purchases from the utility at other times. Net metering can lower the cost to consumers of distributed energy projects. Some consumers are reluctant to install distributed renewable energy resources because many regions do not have the regulatory framework under which consumers can sell energy back to the grid under a net metering system.

Future Energy Sources

As we look to the long-term future of alternative energy technologies, there is significant promise in these technologies to meet an ever-growing portion of our nation’s energy needs.

Hydrogen

In the long run, alternative energy technologies such as hydrogen show great promise. Hydrogen is the most common element in the universe and can be made from water. Converting hydrogen into energy is compatible with existing energy technologies, such as fuel cells, engines, and combustion turbines. The energy for extracting hydrogen could come from existing, traditional fuels, or it could be derived from renewable energy sources, such as solar, nuclear, and fossil, to achieve the cleanest possible energy cycle. Hydrogen can be converted into useful energy forms efficiently and without detrimental environmental effects. Unlike other energy sources, its production by-product is water.

In the future, hydrogen may be able to be used in furnaces and as a transportation fuel for automobiles, buses, trains, ships and airplanes. Hydrogen could also be converted directly into electricity by fuel cells. Combustion of hydrogen with oxygen results in pure steam, which has many appli-



There is a significant promise in renewable technologies to meet an ever-growing portion of our nation's energy needs. Wind power has significant growth potential. The principal challenges to achieving this level of renewable energy generation are cost and market acceptance of renewable power technologies.

U.S. DEPARTMENT OF ENERGY, NATIONAL
RENEWABLE ENERGY LABORATORY

cations in industrial processes and space heating. Moreover, hydrogen is an important industrial gas and raw material in numerous industries, such as computer, metallurgical, chemical, pharmaceutical, fertilizer and food industries.

An energy infrastructure that relies on hydrogen could enable much greater use of distributed energy systems. These systems are small, modular electricity generators that can be placed right where they are needed for heating, cooling, and powering offices, factories, and residences. Hydrogen fuel cells are a promising type of distributed energy system that can provide the exacting reliability needed for the high-tech industry.

Fuel cells can produce electricity and heat from hydrogen, natural gas, and petroleum fuels, and fuel gases derived from coal and biomass. What makes fuel cells unique is that they can use fuels without combustion, simply by chemical reactions, making them extremely clean and efficient.

Fuel cells were developed by the National Aeronautics and Space Administration to generate electricity, heat, and water in space vehicles. The first-generation fuel cells for stationary power applications entered the commercial market in 1995. This type of fuel cell is used to generate very high-quality electricity and heat with negligible emissions in commercial and industrial settings. It is most likely to be used in cases where users are willing to pay a premium for cleaner, more reliable power than is available from the commercial grid.

The second generation of stationary fuel cells is currently in the demonstration phase, including a combined fuel cell–turbine hybrid. These fuel cells are expected to be more efficient and cost less when used in similar distributed energy systems. Smaller fuel cells for residential units are also being developed, and some are in the demonstration phase.

Despite technical progress, high costs remain the main deterrent to widespread fuel cell use. Significant cost reductions must be achieved before fuel cells will be competitive with internal combustion engines, and the size and weight of fuel cell systems must be reduced even more to ac-

commodate vehicle packaging requirements.

The primary challenge to using more hydrogen in our energy systems is the cost of producing, storing, and transporting it. A serious challenge confronting a move toward distributed energy is the transition away from centralized energy systems of supply and production. These challenges are not expected to be resolved overnight, but progress made in the last few years has already far surpassed the expectations of just a decade ago.

A significant amount of promising research and development has already been completed. The automobile industry is aggressively exploring the fuel cell as the future of the industry. Moreover, a new first generation class of distributed energy technologies are already hitting the market.

Fusion

Fusion—the energy source of the sun—has the long-range potential to serve as an abundant and clean source of energy. The basic fuels, deuterium (a heavy form of hydrogen) and lithium, are abundantly available to all nations for thousands of years. There are no emissions from fusion, and the radioactive wastes from fusion are short lived, only requiring burial and oversight for about 100 years. In addition, there is no risk of a melt-down accident because only a small amount of fuel is present in the system at any time. Finally, there is little risk of nuclear proliferation because special nuclear materials, such as uranium and plutonium, are not required for fusion energy. Fusion systems could power an energy supply chain based on hydrogen and fuel cells, as well as provide electricity directly.

Although still in its early stages of development, fusion research has made some advances. In the early 1970s, fusion research achieved the milestone of producing 1/10 of one watt of fusion power, for 1/100 of a second. Today the energy produced from fusion is 10 billion times greater, and has been demonstrated in the laboratory at powers over 10 million watts in the range of a second.

Internationally, an effort is underway in Europe, Japan, and Russia to develop plans for constructing a large-scale fusion science and engineering test facility. This test facility may someday be capable of steady operation with fusion power in the range of hundreds of megawatts.

Both hydrogen and fusion must make significant progress before they can be come viable sources of energy. However, the technological advances experienced over the last decade and the advances yet to come will hopefully transform the energy sources of the distant future.

Recommendation:

- ★ The NEPD Group recommends that the President direct the Secretary of Energy to develop next-generation-technology—including hydrogen and fusion.-
- Develop an education campaign that communicates the benefits of alternative forms of energy, including hydrogen and fusion.
- Focus research and development efforts on integrating current programs regarding hydrogen, fuel cells, and distributed energy.

Current Markets for Renewable and Alternative Energy Advances in Technology

Non-hydropower renewable energy accounts for about 4 percent of current U.S. energy production, divided evenly between electricity generation and transportation fuels such as ethanol. Between 1990 and 1999, renewable energy generation grew by 29 percent, and renewable energy is projected to continue to grow (Figure 6-1). Renewable fuel consumption, including ethanol for gasoline blending, is projected to grow at an average rate of 1.1 percent a year through 2020. In 2020, 55 percent of renewables are projected to be used for electricity generation and the rest for dispersed heating, industrial uses, and fuel blending.

The success of renewables is, in part,

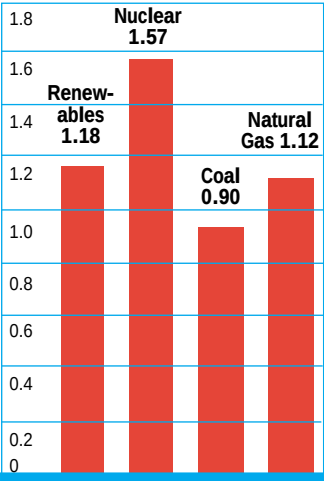
the result of over twenty years of research, development, and demonstration conducted by the public and private sectors. This work has dramatically improved these technologies and has reduced their costs by as much as 90 percent. For example:

- The Department of Energy (DOE), the National Renewable Energy Laboratory (NREL), and Alstom Energy Systems jointly created Advanced Direct-Contact Condensers, which improve the efficiency and generating capacity of electric power plants by providing the best surface area for condensing spent steam. This technological advance, tested in geothermal applications in California, can improve the efficiency of electricity production by 5 percent and capacity by 17 percent.
- United Solar Systems in Michigan pioneered the first commercial use of solar photovoltaics as a building material. The triple-junction, thin-film technology is now sold as flexible solar panels, solar shingles for building roofs, and a peel-and-stick-on variety for standing seam metal roofs. United Solar is now building a larger manufacturing plant in Michigan that is five times the size of its existing manufacturing facility. DOE collaborates with United Solar on research and development helping overcome hurdles in manufacturing. As a result, United Solar is able to provide unique solar electric products using a unique roll-to-roll manufacturing process.

• In partnership with DOE, NREL, Battelle Lab, Burlington Electric and others, Future Energy Resources Corporation of Norcross, Georgia, was able to build, test, and operate the world's first biomass gasification system. The McNeil Plant, located in Burlington, Vermont, gasifies rather than combusts wood chips to power a gas boiler. The technology has shown itself to be commercially viable, and is being considered worldwide by industries as a way of upgrading existing inefficient and aging boilers.

Improved renewable and alternative energy technologies are becoming increasingly attractive to a number of energy companies seeking to build new business opportunities for the future (Figure 6-3). Following are a few examples:

Figure 6-1
Increases in U.S. Energy Production: 1990–1999
(Quadrillion Btus)



During the last decade, renewable energy sources contributed substantially to the growth in U.S. energy production, outpacing all fuel sources except for nuclear energy.

Source: U.S. Department of Energy, Energy Information Administration.

Table 6-2

Electricity Generated by Renewable Energy Sources: 1999

	Solar	Wind	Geothermal	Biomass	Hydropower
Current net summer capacity (MW)	350	2,600	2,870	6,170	79,130
Annual generation (millions of kWh)	940	4,460	13,070	36,570	312,000
Expected growth in generation (%)	PV: 19.3 Thermal: 21	5.3	3.3	3.0	-0.1
Cost (cents/kWh)	20	4–6	5–8	6–20	2–6

Renewable energy has become a significant source of electric power in the United States.

Note: Capacity, generation, and growth data do not include off-grid electricity, thermal, or other nonelectricity energy production, municipal solid waste, or methane from landfills.

Sources: U.S. Department of Energy, Energy Information Administration and Office of Power Technologies.

- FPL Group announced in January 2001 the construction of two major wind farms: a 300 MW facility on the Washington–Oregon border, and a 25.5 MW facility in Wisconsin. The company now has more than 1,000 MW of wind generating capacity in operation or under construction in seven states.

- CalEnergy Company has made renewable and alternative energy generation a central focus of its power portfolio. The company operates 1,300 MW of geothermal, natural gas, hydropower, and other power facilities in the U.S. and abroad, with an other 750 MW currently under construction.

- General Motors, Ford, DaimlerChrysler, Texaco, BP/Amoco, and Shell are collectively spending between \$500 million and \$1 billion dollars a year on fuel cells, hydrogen storage, and infrastructure development for passenger vehicles. Ongoing bus demonstrations in the United States and Europe are expected to commercialize fuel cell power hydrogen buses in the next five years.

Because alternative and renewable energy resources can be used in so many different ways throughout the economy to produce so many combinations of energy types, their total use is often difficult to measure precisely. As of 1996, California alone had over 10 MW of installed distributed energy, a large increase in generating

capacity during a period of otherwise limited growth in generation (Figure 6-3). In 1999, several types of renewable energy were used to produce electricity (Table 6-2).

On the transportation side, there are approximately 450,000 alternative fuel vehicles in the United States. Additionally, there are more than 1.5 million flexible-fuel vehicles that can use gasoline or a high mixture of ethanol and gasoline. These include the Ford Taurus, the DaimlerChrysler Caravan, and the General Motors S10 pickup. Ethanol is the most widely used biofuel, and its production is currently 1.9 billion gallons a year, representing a nearly ten-fold growth from about 200 million gallons a year in 1980.

Recommendation:

★ The NEPD Group recommends that the President direct the Secretary of the Treasury to work with Congress to develop legislation to provide for a temporary income tax credit available for the purchase of new hybrid or fuel-cell vehicles.-

Hybrid Electric Vehicles

Hybrid electric vehicles (HEVs) combine the internal combustion engine of a conventional engine with the battery and electric motor of an electric vehicle, resulting in twice the fuel economy of conventional vehicles. This combination offers the extended range and rapid refueling that consumers expect from a conventional vehicle, with a significant portion of the energy and environmental benefits of an electric vehicle. The practical benefits of HEVs include improved fuel economy and lower emissions compared to conventional vehicles. The car's flexibility will mean convenient use for individuals as well as businesses.

Removing Barriers to Renewable and Alternative Energy Growth

Perhaps the greatest barrier to growth of renewable energy is cost. Currently, the cost of renewable energy generation fre

quently exceeds the costs of conventional electricity generation. In recent years, though, the costs of renewable energy have declined substantially. For example, the cost of wind energy has declined by more than 80 percent over the past twenty years and is increasingly competitive with conventional electricity generation sources. Wind, biomass, and geothermal are all in creasingly competitive with conventional electricity generation.

The ability of these technologies to meet specific market needs is another factor in how quickly their market share will grow. These technologies and energy sources provide multiple benefits to the en ergy producer and the consumer. For ex ample, many of these technologies are modular and can be constructed rapidly, adding an immediate source of new power in areas that otherwise might face a short fall. Distributed renewable energy re sources can enhance the reliability and quality of power.

Cogeneration uses of waste products and heat can increase profits by reducing purchased electricity costs, as well as costs for process steam and heating or cooling. Several sectors, including lumber and paper, steel, and chemical manufacturing, are ex ploring the increased use of cogeneration. With the technological development of biom ass gasification, the lumber and paper indus try could become a seller of electricity.

Recommendation:

★ The NEPD Group recommends that the President direct the Adminis trator of the Environmental Protec tion Agency to issue guidance to encourage the development of well designed combined heat and power (CHP) units that are both highly efficient and have low emissions. The goal of this guidance would be to shorten the time needed to obtain each permit, provide certainty to industry by ensuring consistent implementation across the country, and encourage the use of these cleaner, more efficient technologies.

Renewable technologies can help pro vide insurance against price volatility. In ad dition, many renewable technologies can help industry achieve compliance with the Clean Air Act and other environmental regu lations. In some cases, renewables can be more readily located in urban areas whose air quality does not meet regulatory require ments.

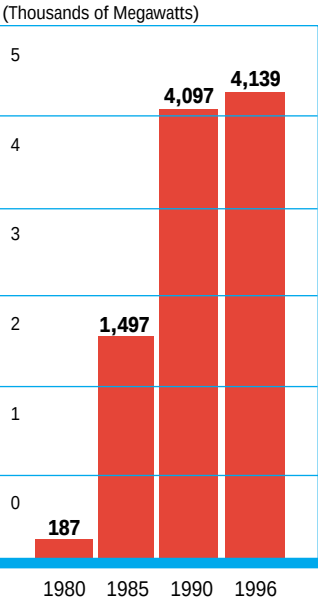
With the growth rate for non-hydro power renewable electricity generation more than doubling the expected growth in overall electricity capacity, these energy sources will play a more significant role in electricity markets in the next two decades. However, the extent to which these domes tic resources are successfully tapped will depend in large part on continued techno logical development.

For renewable and alternative energy to play a greater role in meeting our energy de mands, these sources of generation must be able to integrate into our existing distribution system. The tools that form the necessary in terface between distributed energy systems and the grid need to be less expensive, faster, more reliable, and more compact.

Promising technologies exist that will improve the transmission, storage, and reli ability of renewable energy. An example of recent technological success that will allow for increased access to all forms of energy, including renewable energy, is the high-tem perature superconducting underground power transmission cables that the Depart ment of Energy is developing in partnership with industry. These cables will allow a 300 percent increase in capacity without exca vation to lay new transmission lines. This summer, Detroit Edison is demonstrating this commercially viable high-temperature superconducting cable system in an applica tion that serves 14,000 customers.

Renewable and alternative energy technologies, such as wind energy and com bined heat and power could be significantly expanded, given today's technologies. They could be further expanded with added in vestment in technology. For example, wind energy could be developed that could be adapted to sites with lower wind speeds than is feasible today. Combined heat and

Figure 6-3
Growth in California's Renewable Energy Capacity



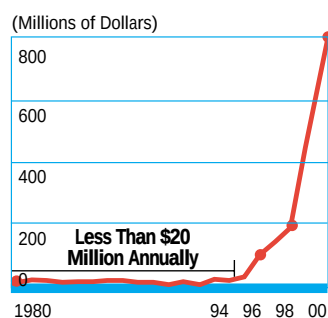
Source: U.S. Department of Energy, Energy Information Administration.



While solar energy technologies have undergone technological and cost improvements, and are well established in high value markets like remote power, satellites, communications, and navigational aids continued research is needed to reduce costs and improve performance.

U.S. DEPARTMENT OF ENERGY

Figure 6-4
Investors Are Betting on Distributed Energy



In the last few years, surging venture capital investments showed strong support for distributed energy technologies.

*Note: Data for 2000 are projected investments.
Source: Nth Power via the Economist, August 5, 2000.*

power in buildings offers great potential for increased system efficiencies and lower costs. New developments in microturbine and fuel cell technologies are also highly promising. Performance improvements of other technologies, such as photovoltaic systems, would facilitate much wider use. In addition to technological performance, attention to several key market and regulatory constraints would accelerate the development and use of renewable and alternative energy in the marketplace.

Because many renewable and alternative energy technologies do not fit into traditional regulatory categories, they are often subjected to competing regulatory requirements or to requirements that were never designed to address them. For example, much of the current Clean Air Act does not specifically address the use of new, more efficient renewable energy technologies. Consequently, the Act does not provide significant incentives for the development of such technologies.

The lack of interconnection standards or guidelines for electricity supply and loads impedes the use of distributed energy technologies. As a result, developers of small renewable energy projects must negotiate interconnection agreements on a site-by-site basis with local distribution companies that are often opposed to distributed energy projects because of the increased competition. Although a few states have established interconnection standards, there is no national standard to facilitate development of distributed energy (Figure 6-4).

New combined heat and power facilities may face air permitting hurdles when they replace marginally dirty boilers. The Clean Air Act does not recognize the pollution prevention benefits of the increased efficiency of combined heat and power units. At the same time, these combined heat and power investments are taxed at the industry's tax rate, not at the rate they would receive if they were considered part of the utility sector for tax purposes.

In addition, modifications to permitting and siting requirements may be necessary to facilitate the incorporation of these technologies into buildings.

The infrastructure needed for increasing the use of renewable and alternative energy varies considerably. In particular, the alternative fuels infrastructure lags far behind the existing infrastructure for conventional fuels. The lack of infrastructure for alternative fuels is a major obstacle to consumer acceptance of alternative fuels and the purchase of alternative fuel vehicles. It is also one of the main reasons why most alternative fuel vehicles actually operate on petroleum fuels, such as gasoline and diesel. In addition, a considerable enlargement of ethanol production and distribution capacity would be required to expand beyond their current base in the Midwest in order to increase use of ethanol-blended fuels.

The use of natural gas or electricity for vehicles requires enhancements to these distribution systems, such as compression stations for natural gas. While many alternative fuels can be shipped by pipeline, they may require separation within the pipeline to avoid mixing different energy products. Geographically dispersed renewable energy plants often face significant transmission barriers, including unfavorable grid schedule policies and increased embedded costs.

Uncertainty regarding the tax treatment of these technologies and energy sources can discourage long-term investment. Though existing tax credits provide an incentive for investing in some types of renewable energy, the limited scope of the credit and its frequent expiration discourages investment.

Summary of Recommendations

Nature's Power: Increasing America's Use of Renewable and Alternative Energy

- ★ The NEPD Group recommends that the President direct the Secretaries of the Interior and Energy to re-evaluate access limitations to federal lands in order to increase renewable energy production, such as biomass, wind, geothermal, and solar.
- ★ The NEPD Group supports the increase of \$39.2 million in the FY 2002 budget amendment for the Department of Energy's Energy Supply account that would provide increased support for research and development of renewable energy resources.
- ★ The NEPD Group recommends that the President direct the Secretary of Energy to conduct a review of current funding and historic performance of renewable energy and alternative energy research and development programs in light of the recommendations of this report. Based on this review, the Secretary of Energy is then directed to propose appropriate funding of those research and development programs that are performance-based and are modeled as public-private partnerships.
- ★ The NEPD Group recommends that the President direct the Secretary of the Treasury to work with Congress on legislation to expand the section 29 tax credit to make it available for new landfill methane projects. The credit could be tiered, depending on whether a landfill is already required by federal law to collect and flare its methane emissions due to local air pollution concerns.
- ★ The NEPD Group recommends that the President direct the Secretary of the Interior to determine ways to reduce the delays in geothermal lease processing as part of the permitting review process.
- ★ The NEPD Group recommends that the President direct the Administrator of the Environmental Protection Agency to develop a new renewable energy partnership program to help companies more easily buy renewable energy, as well as receive recognition for the environmental benefits of their purchase, and help consumers by promoting consumer choice programs that increase their knowledge about the environmental benefits of purchasing renewable energy.
- ★ The NEPD Group recommends that the President direct the Secretary of the Treasury to work with Congress on legislation to extend and expand tax credits for electricity produced using wind and biomass. The President's budget request extends the present 1.7 cents per kilowatt hour tax credit for electricity produced from wind and biomass; expands eligible biomass sources to include forest-related sources, agricultural sources, and certain urban sources; and allows a credit for electricity produced from biomass co-fired with coal.
- ★ The NEPD Group recommends that the President direct the Secretary of the Treasury to work with Congress on legislation to provide a new 15 percent tax credit for residential solar energy property, up to a maximum credit of \$2,000.
- ★ The NEPD Group recommends that the President direct the Secretaries of the Interior and Energy to work with Congress on legislation to use an estimated \$1.2 billion of bid bonuses from the environmentally responsible leasing of ANWR for funding research into alternative and renewable energy resources, including wind, solar, geothermal, and biomass.

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- ★ The NEPD Group recommends that the President direct the Secretary of the Treasury to work with Congress to continue the ethanol excise tax exemption.
 - ★ The NEPD Group recommends that the President direct the Secretary of Energy to develop next-generation technology—including hydrogen and fusion.
 - Develop an education campaign that communicates the benefits of alternative forms of energy, including hydrogen and fusion.
 - Focus research and development efforts on integrating current programs regarding hydrogen, fuel cells, and distributed energy.
 - Support legislation reauthorizing the Hydrogen Energy Act.
 - ★ The NEPD Group recommends that the President direct the Secretary of the Treasury to work with Congress to develop legislation to provide for a temporary income tax credit available for the purchase of new hybrid or fuel-cell vehicles between 2002 and 2007.
 - ★ The NEPD Group recommends that the President direct the Administrator of the Environmental Protection Agency to issue guidance to encourage the development of well-designed combined heat and power (CHP) units that are both highly efficient and have low emissions. The goal of this guidance would be to shorten the time needed to obtain each permit, provide certainty to industry by ensuring consistent implementation across the country, and encourage the use of these cleaner, more efficient technologies.

America's Energy Infrastructure

A Comprehensive Delivery System

One of the greatest energy challenges facing America is the need to use 21st-century technology to improve America's aging energy infrastructure. Americans need a comprehensive, long-term solution to deliver energy to industry and consumers in a reliable and safe manner.

Our energy infrastructure is comprised of many components, such as the physical network of pipes for oil and natural gas, electricity transmission lines and other means for transporting energy to consumers. This infrastructure also includes facilities that turn raw natural resources into useful energy products. The rail network, truck lines, and marine transportation are also key components of America's energy infrastructure.

The energy industry has undergone major changes in the last two decades, and more are expected. These changes affect how our energy infrastructure operates. For example, while the electricity industry was once vertically integrated, it is increasingly separated into three isolated segments: generation, transmission, and distribution.

Our energy infrastructure has failed to keep pace with the changing requirements of our energy system. Domestic refining capacity has not matched increases in demand, requiring the United States to import refined products. Natural gas pipelines have not expanded sufficiently to meet demand. The electricity transmission system is constrained by insufficient capacity. Rail capacity was significantly increased during the 1970s when rail facilities were improved to move more coal. Since then, however, few additions to the coal transportation rail network have been built.

The United States needs to modernize its energy infrastructure. One sign of a lack of an energy policy in recent years has been the failure to maintain the infrastructure needed to move energy where it is needed most.

Electricity

The electricity infrastructure includes a nationwide power grid of long-distance transmission lines that move electricity from region to region, as well as the local distribution lines that carry electricity to homes and businesses. Electricity originates at power plants, which are primarily fueled by coal, nuclear, natural gas, water and, to a lesser extent, oil. Coal, natural gas and oil powered plants require a dependable transportation infrastructure to deliver the fuels necessary for the production of electricity. A transportation network for waste disposal is also necessary for power plants that create by products.

Restructuring

The electricity industry has undergone considerable changes in the last two decades. These changes affect how our electricity infrastructure operates. Major industry restructuring has separated once vertically integrated electric utilities that supplied generation, transmission, and distribution services into distinct entities. To facilitate competition at the wholesale level, in 1996, the Federal Energy Regulatory Commission (FERC) required transmission-owning utilities to "unbundle" their transmission and power marketing functions, and provide nondiscriminatory, open access to their transmission systems by other utilities

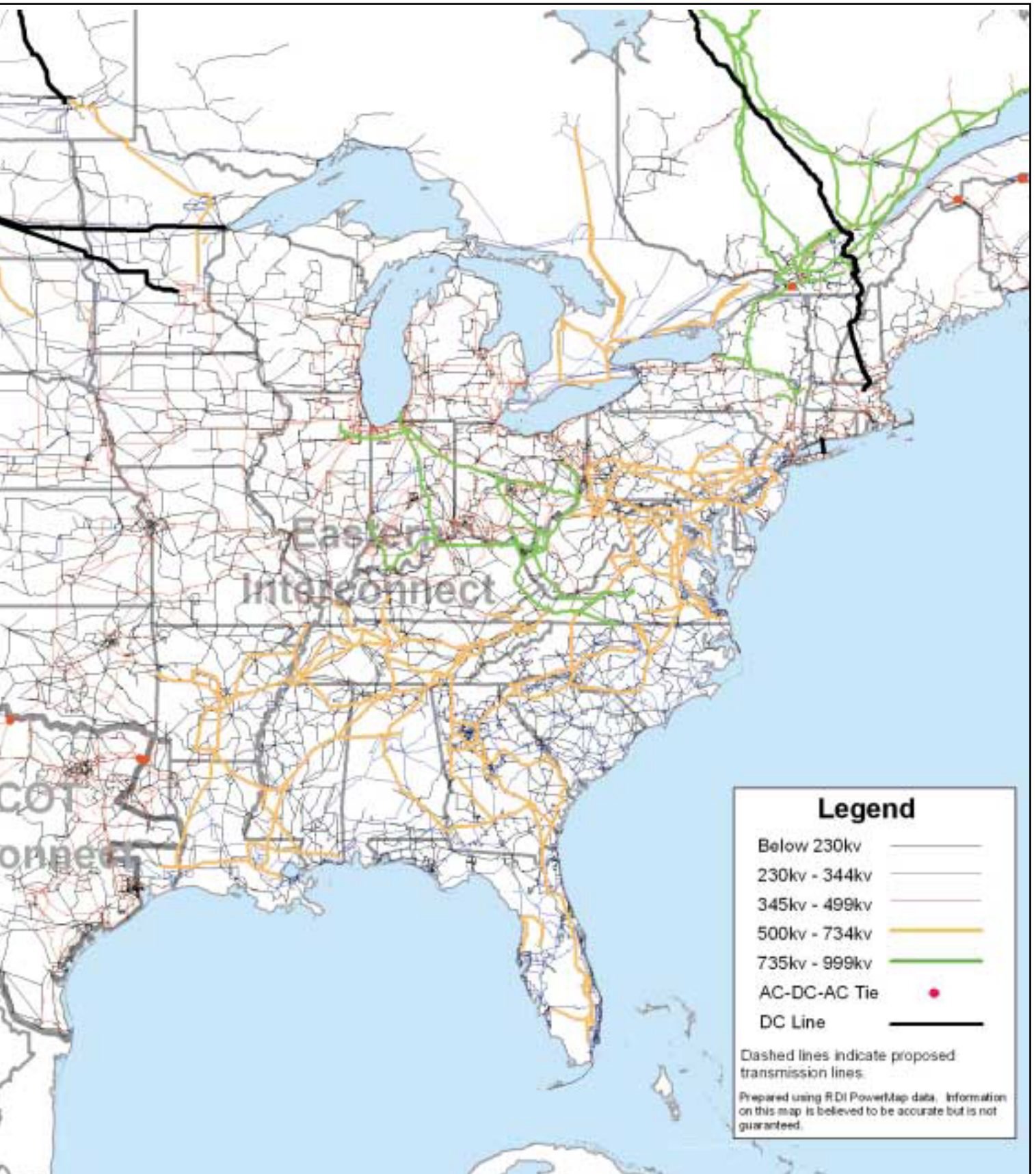


FIGURE 7-1
**North American
Transmission Lines**

About 204,000 miles of long-distance transmission lines move power from region to region. The four integrated transmission grids serving North America are the Western Interconnection, Eastern Interconnection, Electric Reliability Council of Texas, and Province of Quebec.

Source: PA Consulting Group





and independent power producers. At the retail level, some states have required utilities to divest their generation assets as part of restructuring. These utilities currently supply only transmission and distribution services for customers who purchase electricity (i.e., generation services) from other firms. In addition, power marketers—who often do not own generation, transmission, or distribution facilities—buy and sell power on wholesale markets and market electricity directly to customers.

Electricity competition has led to significant changes in the operation of the bulk power grid, which are the power plants and high-voltage transmission facilities that make up the wholesale power market. More electricity is being shipped longer distances over a transmission system that was initially designed only to provide limited power and reserve sharing among neighboring utilities. Electric utilities that were once solely responsible for ensuring that adequate generation was available to meet demand now purchase a substantial amount of the power they need from the wholesale market, relying on independent power producers to build and operate plants.

Electricity Generation

There are roughly 5,000 power plants in the United States, and they have a total generating capacity of nearly 800,000 megawatts. Over the past few years, there has been an explosion of “merchant” power plants proposed by independent power producers seeking to sell into wholesale markets. In spite of this interest, a number of regions of the country are experiencing capacity shortages as a result of wholesale market design problems and barriers to siting and building new power plants.

Over the next ten years, demand for electric power is expected to increase by about 25 percent, and more than 200,000 megawatts of new capacity will be required. However, under current plans electric transmission capacity will increase by only 4 percent. This shortage could lead to serious transmission congestion and reliability problems.

Transmission Grid

The United States does not have a national transmission grid. Instead, there are four integrated transmission grids serving North America: the Western Interconnection, Eastern Interconnection, Electric Reliability of Council of Texas, and the Province of Quebec (Figure 7-1). These regional grids themselves are international, encompassing the United States, Canada, and part of Mexico.

Transactions between the four integrated transmission grids are very limited because they are interconnected at only a few locations through interties, so for all practical purposes they can be viewed as separate transmission grids. The four integrated transmission grids break down into a series of smaller regions, largely defined by transmission constraints. Altogether, 204,000 miles of transmission lines in North America move power from the point of generation to where electricity is needed. There are 157,810 miles of transmission lines in the United States. Transmission grid expansions are expected to be slow over the next ten years, with additions totaling only 7,000 miles.

The transmission system is the highway system for interstate commerce in electricity. Transmission allows the sale of electricity between regions. In a particular region, transmission can be a substitute for generation, allowing that region to import power that otherwise would have to be generated within that region. In some cases, transmission expansion may be more cost effective than generation additions, allowing a region better access to lower-cost generation.

Transmission constraints limit these power flows, and result in consumers paying higher prices for electricity. The electricity price spikes in the Midwest in the summer of 1998 were caused in part by transmission constraints limiting the ability of the region to import electricity from other regions of the country that had available electricity. During the summer of 2000, transmission constraints limited the ability to sell low-cost power from the Midwest to the South during a period of peak demand,

resulting in higher prices for consumers. Transmission capacity limits could result in price pressures and reliability problems this summer in California, Long Island, the Great Lakes, the Southeast, and New England (Figure 7-2).

Regional shortages of generating capacity and transmission constraints combine to reduce the overall reliability of electric supply in the country and are reducing the quality of power delivered to end users. Power quality is becoming an increasingly important issue as our digital economy continues to grow.

One factor limiting reliability is the lack of enforceable reliability standards. Since 1968, the reliability of the U.S. transmission grid has depended entirely on voluntary compliance with reliability standards. There is a broad recognition that voluntary adherence with reliability standards is no longer a viable approach in an increasingly competitive electricity market. There is a need to provide for enforcement of mandatory reliability standards. Broad support has emerged for development of these standards by a self-regulating organization overseen by FERC.

Recommendations:

★ The NEPD Group recommends that the President direct the Secretary of Energy to work with FERC to improve the reliability of the interstate transmission system and to develop legislation providing for enforcement by a self-regulatory organization subject to FERC oversight.

★ The NEPD Group recommends that the President direct the Secretary of Energy to expand the Department's research and development on transmission reliability and superconductivity.

Transmission constraints were also a primary factor in blackouts in northern California, which imports power from both the Northwest and southern California. When resources are not available in the Northwest, electricity supply must come

Figure 7-2

Current Electric Power Bottlenecks



Transmission capacity limits could result in price pressures and reliability problems this summer in California, Long Island, the Great Lakes, the Southeast, and New England. The arrows in this figure depict the locations and directions of current transmission congestion.

Source: North American Electric Reliability Council.

from southern California's Path 15 transmission route. Path 15 does not have sufficient capacity to provide all of the power needed in northern California.

Recommendation:

★ The NEPD Group recommends that the President direct the Secretary of Energy to authorize the Western Area Power Administration to explore relieving the "Path 15" bottleneck through transmission expansion financed by nonfederal contributions.

Transmission constraints have been a persistent cause of price spikes in New York City in recent years. The New York Independent System Operator (the grid operator in that state) estimates that the city will be short about 400 MW below their desired reserve margin of power during the summer peak. To fill this gap, the New York Power Authority is trying to install additional generation capacity in the city. Market-oriented approaches could also be used to create additional capacity and alleviate some of the potential problems.

If transmission constraints are not removed, the result can be higher prices and

lower reliability. There are various reasons why transmission constraints exist. One is the lack of sufficient investment in transmission. Transmission investment has lagged dramatically over the past decade (Figure 7-3). There is a need to ensure that transmission rates create incentives for adequate investment in the transmission system, especially as restructuring leads to the creation of transmission companies whose only business is operation of transmission facilities. FERC recognizes this need and has expressed a willingness to consider innovative transmission pricing proposals.

Another cause of transmission constraints is the siting process. Under current law, siting of transmission facilities is a responsibility of state governments, not the federal government, even though the transmission system is not only interstate but also international, extending into both Canada and Mexico. This stands in stark contrast to siting of other interstate facilities, such as natural gas pipelines, oil pipelines, railroads, and interstate highways.

Federal law governing the responsibility for siting transmission facilities was written in 1935, nearly 80 years ago. At the time, transmission facilities were not inter-

state, and there was virtually no interstate commerce in electricity. Congress did not anticipate the development of an interstate and international transmission system.

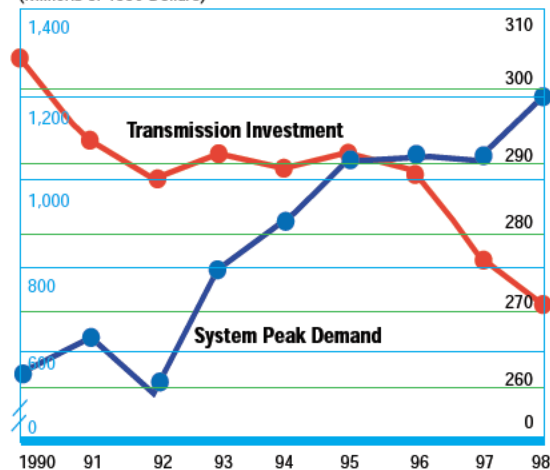
State decisions on where to locate transmission lines often do not recognize the importance of proposed transmission facilities to the interstate grid. For example, a recent decision by regulators in Connecticut to block a proposed transmission line to Long Island did not recognize the need for electricity on Long Island. Some state siting laws require that the benefits of a proposed transmission facility accrue to the individual state, resulting in the rejection of transmission proposals that benefit an entire region, rather than a single state.

Much has changed since 1935. The transmission system is the highway for interstate commerce in electricity. Transmission constraints are resulting in higher prices for consumers and lower reliability. The siting process must be changed to reflect the interstate nature of the transmission system.

Figure 7-3

U.S. Investment in New Electric Power Transmission

(Millions of 1990 Dollars)



Growth in peak demand for electricity has far outstripped investment in transmission capacity. As a result, transmission constraints could aggravate already limited supplies of power and could result in high prices in some areas of the country.

Source: PA Consulting Group, based on data from the UDI data base.

Recommendations:

★ The NEPD Group recommends that the President direct the appropriate federal agencies to take actions to remove constraints on the interstate transmission grid and allow our nation's electricity supply to meet the growing needs of our economy.-

- Direct the Secretary of Energy, by December 31, 2001, to examine the benefits of establishing a national grid, identify transmission bottle necks, and identify measures to remove transmission bottlenecks.
- Direct the Secretary of Energy to work with FERC to relieve transmission constraints by encouraging the use of incentive rate-making proposals.
- Direct the federal utilities to determine whether transmission expansions are necessary to remove constraints. The Administration should review the Bonneville Power Administration's (BPA's) capital and



financing requirements in the context of its membership in a regional RTO, and if additional Treasury financing appears warranted or necessary in the future, the Administration should seek an increase in BPA's borrowing authority at that time.

- Direct the Secretary of Energy, in consultation with appropriate federal agencies and state and local government officials, to develop legislation to grant authority to obtain rights-of-way for electricity transmission lines, with the goal of creating a reliable national transmission grid. Similar authority already exists for natural gas pipelines in recognition of their role in interstate commerce.

Another cause of transmission constraints is limited access to federal lands. The federal government is the largest land owner in the United States and owns most of the land in some western states. Limited access to federal lands can block needed transmission expansion. A case in point is a transmission line being built from West Vir-

ginia to Virginia. Five years ago, the Department of Energy identified that line as critical to the reliability of the transmission system on the East Coast. Five years later, the line is still not complete. Improved access to federal land can help remove transmission constraints.

Rights-of-Way on Federal Lands

The Bureau of Land Management (BLM) estimates that 90 percent of the oil and natural gas pipeline and electric transmission rights-of-way in the western United States cross federal lands. These lands are principally lands managed by either the BLM or the U.S. Forest Service. Rights-of-way are authorized through an approval process that allows the public to comment on proposals to locate infrastructure items, like utility poles, on these rights-of-way. As part of this process, proposals are examined for resource and other use conflicts, and a national interest test is applied prior to approval.

The BLM administers 85,000 rights-of-way, including 23,000 for oil and gas pipelines and 12,000 for electric transmission lines. It processes over 1,200 pipeline and electric system right-of-way applications a year, with an increase in applications of

The electric power infrastructure includes a nationwide "power grid" of long-distance transmission lines that move electricity from the point of generation to where the electricity is needed. Over the next ten years, U.S. demand for electric power is expected to increase by 25 percent, while transmission capacity is expected to increase by only 4 percent.



Virtually all natural gas in the United States is moved via pipeline. The current domestic natural gas transmission capacity of approximately 23 trillion cubic feet (tcf) will be insufficient to meet the projected 50 percent increase in U.S. consumption projected for 2020.

over 10 percent a year in recent years. The demand for additional energy and electricity is expected to increase the need for rights-of-way across federal lands.

Other federal entities also deal with rights-of-way, each approaching the issue from a unique perspective. The National Park Service is authorized to grant leases and permits, but discourages rights-of-way corridors unless there are no practical alternatives. The U.S. Fish and Wildlife Service manages National Wildlife Refuge lands for wildlife and habitat values, and allows corridors where they were pre-existing or are determined to be compatible with the purposes for which a refuge was established. The Bureau of Reclamation is authorized to grant rights-of-way over lands acquired or withdrawn for reclamation purposes, if compatible with authorized project purposes. The Bureau of Indian Affairs and tribal governments are authorized to grant rights-of-way across both tribal and individually owned Indian lands.

Pipelines

After being pumped from the ground in domestic oil fields, oil travels through gathering lines to pipelines, which bring it to refineries, where it is transformed into petroleum products like gasoline, diesel fuel, or heating oil. These products then travel through pipelines and tanker trucks to distribution outlets for purchase by consumers. Natural gas must similarly travel from gas fields through gathering lines to processing facilities, and then into pipelines

and local distribution lines to its final destination. These pipeline systems involve a complex infrastructure of their own, including pump stations or compressor stations, and control systems that open and close valves and switch product flow through pipes, often with the use of computer technology.

Oil Pipelines

The two million miles of oil pipelines in the United States are the principal mode for transporting oil and petroleum products such as gasoline. They account for about 66 percent of domestic product movements (Figure 7-4). Increases in the demand for oil and changes in where it is supplied will lead to the need for more pipeline capacity.

Pipelines are less flexible than other forms of oil transport, because they are fixed assets that cannot be easily adjusted to changes in supply and demand. Once built, they are an efficient way to move petroleum and petroleum products. A modest sized pipeline carries the equivalent of 750 tanker truckloads a day—the equivalent of a truckload leaving every two minutes, 24 hours a day, 7 days a week. Replacing the same pipeline with a railroad train of tank cars, carrying 2,000 barrels each, would require a 75-car train to arrive and be unloaded every day. Pipelines are relatively inexpensive to operate and are generally quiet and safe. Ensuring pipeline safety requires careful management, as multiple products move through a single pipeline system at the same time.

Insufficient domestic pipeline capacity has caused peak-load problems in moving oil and petroleum products such as gasoline from one region of the country to another. For example, many energy analysts forecasted the possibility of a shortage last winter in the upper Midwest of liquefied petroleum gas used for heating and for drying crops. Others were concerned about possible shortages of heating oil in New England.

Energy supply shortages can create operational difficulties for the pipelines themselves. The complex interrelationship

of our energy infrastructure is evident, since pipelines have been shut down for varying time periods due to regional electricity shortages.

For example, fuel supplies to Las Vegas and Phoenix became dangerously low when blackouts in California shut down the main pipeline serving those areas. The California Public Utilities Commission (CPUC) has granted a waiver of penalties to oil pipelines that have interruptible contracts for electricity to help ensure the uninterrupted flow of motor fuel supplies to California. The California Energy Commission asked the CPUC to grant the waiver in order to minimize the threat to public health due to disruptions of fossil fuel supplies. While the waiver of penalties does not guarantee that disruptions of power to petroleum product pipelines will not occur, it diminishes the threat by allowing disruptions to occur only when they are coordinated with the entire petroleum product delivery system, from refiner to pipeline to terminals. Both Phoenix and Las Vegas would benefit from this decision because refineries and pipelines from California supply the two cities.

Much of the existing oil pipeline infrastructure is old, requiring regular safety and environmental reviews to ensure its reliability. The potential risk of pipeline accidents to human health and safety is of grave concern. In June 1999, a petroleum product pipeline ruptured and caught fire in Bellingham, Washington. In addition to tragic loss of life, the pipeline's 18-month shutdown caused an economic hardship to the Seattle-Tacoma Airport and other local businesses that relied on the pipeline for aviation and diesel fuels. To avoid similar crises, the Department of Transportation, which has responsibility for pipeline safety, has adopted regulations and other risk management approaches to ensure safety in pipeline design, construction, testing, operation, maintenance, and emergency response.

Recommendation:

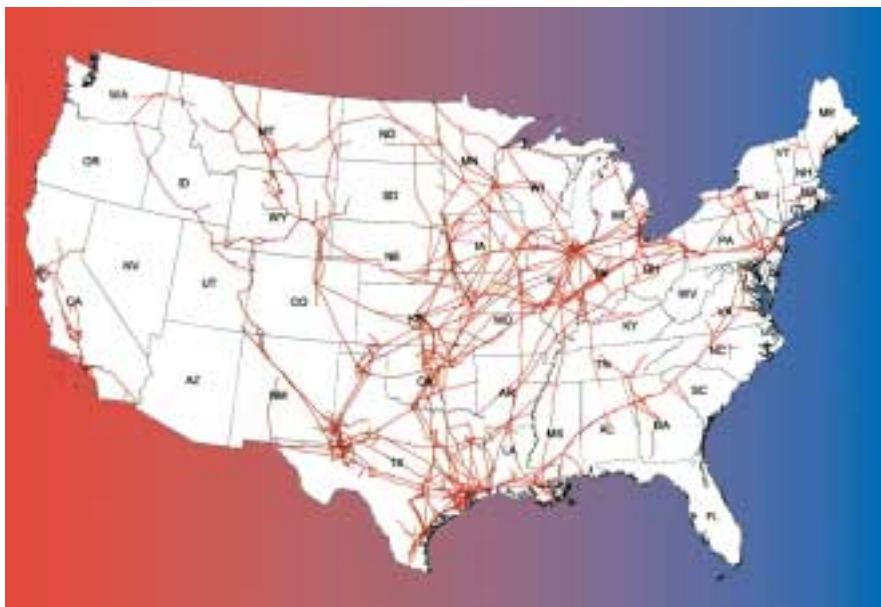
★ The NEPD Group recommends that the President direct the Secretary of the Interior to work with Congress and the State of Alaska to put in place the most expeditious process for renewal of the Trans-Alaskan Pipeline System rights-of-way to ensure that Alaskan oil continues to flow uninterrupted to the West Coast of the United States.-

The Trans-Alaska Pipeline System is the single most important crude oil pipeline in the United States, and is perhaps the most regulated oil pipeline in the world. The pipeline system has carried nearly one-fifth of all domestically produced oil for the last two decades. Since beginning operations in 1977, it has transported more than 13 billion barrels of oil from Alaska's North Slope across 800 miles to the Port of Valdez. Since the pipeline began operation, only 0.00014 percent of the total amount of oil transported through it has been spilled.

The pipeline's federal grant and state lease for right-of-way expires in 2004 and will require renewal. That process will in-

Figure 7-4

U.S. Oil Pipelines



The two million miles of oil pipelines in the United States are the principal mode for transporting crude oil and refined products. They account for about 66 percent of domestic product movements.

Source: U.S. Department of Transportation, Office of Pipeline Safety.



Several federal agencies are authorized to grant rights-of-way for oil and gas pipeline and electric transmission systems on federal lands, and each approaches the issue from a unique perspective. Authorizing agencies include the Bureau of Land Management, the U.S. Forest Service, the National Park Service, the U.S. Fish and Wildlife Service, the Bureau of Reclamation, and the Bureau of Indian Affairs.

volve a thorough review of compliance with federal laws and regulations, including those related to safety and environmental impacts. Because nearly 50 percent of the right-of-way is owned by the State of Alaska, they must also renew the applicable state permits. To commence the formal portion of the federal renewal process, regulations require a renewal application to be filed with the Alaska Office of the BLM of the Department of the Interior. To the extent possible, a single, joint federal/state approach should be considered.

Natural Gas Pipelines

Virtually all natural gas in the United States is moved via pipeline (Figure 7-5). The current domestic natural gas transmission capacity of approximately 23 trillion cubic feet (tcf) will be insufficient to meet the projected 50 percent increase in U.S. consumption projected for 2020.

Some parts of the country, such as California and New England, already face capacity shortages. Several pipeline opera-

tors have applied for permits to increase their delivery of natural gas to California, but right-of-way issues and local permitting delays have constrained the ability to transport natural gas to California, contributing to high prices. In addition, the natural gas pipeline connections from Canada are near capacity, so any greater U.S. reliance on Canadian natural gas will require increased pipeline capacity.

One of the largest known reserves of natural gas in the United States has been found in the Arctic, associated with the development of oil at Alaska's Prudhoe Bay. These known gas reserves, over 35 tcf, would make a significant long-term contribution to the nation's energy supplies if delivered to the lower 48 states. It is estimated there may be an additional 100 tcf on the North Slope of Alaska. Recently, as the energy supply situation has changed, interest has renewed in tapping into Alaska's natural gas supplies. Over the past year, the Alaska North Slope gas producers have been reviewing whether projected market conditions will make transportation of this natural gas economically feasible. The North Slope gas producers are scheduled to complete that review by the end of 2001.

Recommendation:

★ The NEPD Group recommends that the President direct the Secretaries of Energy and State, coordinating with the Secretary of the Interior and the Federal Energy Regulatory Commission, to work closely with Canada, the State of Alaska, and all other interested parties to expedite the construction of a pipeline to deliver natural gas to the lower 48 states. This should include proposing to Congress any changes or waivers of law pursuant to the Alaska Natural Gas Transportation Act of 1976 that may be required.

America needs the energy that Alaska's North Slope natural gas can provide. The Administration seeks to expedite the construction of a pipeline to deliver this natural gas to the lower 48 states.

In addition to shortfalls in capacity, sources of natural gas have shifted from the Southwest to the deep water of the Gulf of Mexico, the Rocky Mountains, western Canada, and the Canadian Atlantic. At the same time, demand has shifted from the industrial Midwest to the growing population centers in the South and the West. An additional 263,000 miles of distribution pipelines and 38,000 miles of new transmission pipelines will be necessary to meet increased consumption and the new geographic realities of supply and demand.

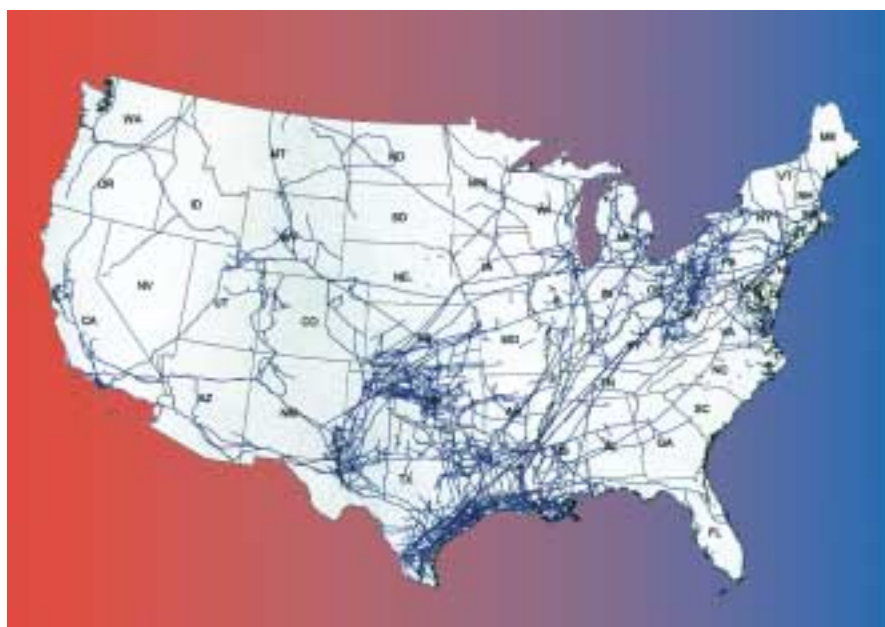
Several factors complicate efforts to meet the need for increased pipeline capacity, including encroachment on existing rights-of-way and heightened community resistance to pipeline construction. Currently it takes an average of four years to obtain approvals to construct a new natural gas pipeline. In some cases it can take much longer.

The projected growth in energy demand has called into question whether regulatory actions and permitting processes can keep pace with the necessary construction of new facilities for storage and delivery. Consistent federal, state, and local government policies, and faster, more predictable regulatory decisions on permitting for oil and natural gas pipelines are needed to enable timely and cost-effective infrastructure development. The permitting process has a positive role in protecting the environment, public health, and safety by allowing all interested parties an opportunity to participate effectively and fully in the deliberations prior to the permit issuance.

Recent pipeline ruptures involving a natural gas pipeline near Carlsbad, New Mexico, and an underground natural gas storage facility near Hutchinson, Kansas, highlight the need to develop technologies and policies that protect people, environment, and the safety of the nation's energy infrastructure. The federal government has an important role in ensuring and improving the safety of these gas pipelines. New technologies need to be developed to improve monitoring and assessment of system integrity, improve data quality for system

Figure 7-5

U.S. Natural Gas Transmission Pipelines



Virtually all natural gas in the United States is moved via pipeline. The forecast of a doubling in the number of new natural gas wells drilled annually and an 80 percent increase in the number of active drilling rigs will require new pipelines.

Source: U.S. Department of Transportation, Office of Pipeline Safety.

planning, extend the serviceability and life of the national natural gas transmission and distribution network, provide safer transport of energy products, and lessen the impacts of the energy infrastructure on the environment.

Recommendations:

★ The NEPD Group recommends that the President support legislation to improve the safety of natural gas pipelines, protect the environment, strengthen emergency preparedness and inspections and bolster enforcement.

★ The NEPD Group recommends that the President direct agencies to continue their interagency efforts to improve pipeline safety and expedite pipeline permitting in an environmentally-sound manner and encourage the Federal Energy Regulatory Commission to consider improvements in the regulatory process governing approval of interstate-natural gas pipeline projects.



U.S. demand for refined petroleum products currently exceeds its domestic capacity to produce them. The refinery industry is now running at nearly 100 percent of capacity during the peak gasoline consumption season.

Oil Refineries

U.S. demand for refined petroleum products, such as gasoline and heating oil, currently exceeds our domestic capacity to produce them. The refinery industry is now running at nearly 100 percent of capacity during the peak gasoline consumption season and is producing record levels of needed products at other times. The excess demand has recently been met by increased imports.

The U.S. refining industry has experienced a decade of low profitability and rates of return on investment. This has discouraged investment in new refineries. In fact, almost 50 U.S. refineries closed over the last ten years, and no major refineries have been built in the last twenty-five years.

During the last ten years, overall refining capacity grew by about 1 to 2 percent a year as a result of expansion in the capacity of existing, larger refineries. Although there was a significant, sustained improvement in margins during 2000, those gains arose out of a very tight supply situation and high, volatile prices. Industry consolidation has been a key response to this poor profitability.

The U.S. refining industry is also facing major infrastructure problems. While the industry expanded steadily through the 1970s, it went through a period of consolidation after the oil shocks of 1973 and 1978.

Ongoing industry consolidation, in an effort to improve profitability, inevitably leads to the sale or closure of redundant facilities by the new combined ownership. This has been particularly true of terminal facilities, which can lead to reductions in inventory and system flexibility. While excess capacity may have deterred some new capacity investments in the past, more recently, other factors, such as regulations, have deterred investments.

Refiners are subject to significant environmental regulation and face several new clean air requirements over the next decade. Refiners will face many clean fuel production standards, which require the production of many different kinds of gasoline and diesel fuel for different parts of the country. New Environmental Protection Agency rules will require refiners to produce gasoline and diesel fuel with significantly lower sulfur content. New clean air requirements will benefit the environment, but will also require substantial capital investments and additional government permits. The proliferation of distinct regional and state gasoline and diesel product standards, the significant permitting needed, and the downtime to make the needed physical and operational changes will challenge refiners and governments to effectively coordinate in order to reduce the likelihood of supply shortfalls and price spikes.

Recommendation:

★ The NEPD Group recommends that the President direct the Administrator of the EPA to study opportunities to maintain or improve the environmental benefits of state and local “boutique” clean fuel programs while exploring ways to increase the flexibility of the fuels distribution infrastructure, improve fungibility, and provide added gasoline market liquidity. In concluding this study, the Administrator shall consult with the Departments of Energy and Agriculture, and other agencies as needed.

Since 1990, refiners have met growing demand by increasing the use of existing equipment and increasing the efficiency and capacity of existing plants. Even with these efforts, however, refining capacity has begun to lag behind peak summer demand. Price volatility and the cyclical nature of oil markets inhibit investment in supply infrastructure. While investors can withstand market fluctuations for some commodities, large investments in oil exploration and development—such as for drilling required to maintain a steady supply and the pipelines needed to bring supply to market—are often curtailed during times of low oil prices. The outcome of this lack of steady investment is less supply, higher prices, and the abandonment of marginal oil resources that may never be recovered.

Recommendations:-

★ The NEPD Group recommends that the President direct the Administrator of the Environmental Protection Agency and the Secretary of Energy to take steps to ensure America has adequate refining capacity to meet the needs of consumers.-

- Provide more regulatory certainty to refinery owners and streamline the permitting process where possible to ensure that regulatory overlap is limited.
- Adopt comprehensive regulations

(covering more than one pollutant and requirement) and consider the rules’ cumulative impacts and benefits.

★ The NEPD Group recommends that the President direct the Administrator of the Environmental Protection Agency, in consultation with the Secretary of Energy and other relevant agencies, to review New Source Review regulations, including administrative interpretation and implementation, and report to the President within 90 days on the impact of the regulations on investment in new utility and refinery generation capacity, energy efficiency, and environmental protection.

- The NEPD Group recommends that the President direct the Attorney General to review existing enforcement actions regarding New Source Review to ensure that the enforcement actions are consistent with the Clean Air Act and its regulations.

Energy Transportation Infrastructure

The infrastructure used to transport energy products includes ocean tankers; in land barges; specialized trucks for oil and refined products, such as gasoline and heating oil; railroad tank cars and coal cars; and the waterways, highways, and railroads upon which they travel. There is also a substantial inventory of river and oceanside port facilities that are used for moving energy materials.

Marine Transportation

Marine transportation of oil and refined products accounts for nearly one-third of domestic shipments. Approximately 3.3 billion barrels of oil and petroleum products and 229 million short tons of coal move through the nation’s ports and waterways every year.

There are three kinds of ship transport of domestic energy products. Tankers



Double-hulled tank barges provide distribution of petroleum products.

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primarily carry Alaskan oil to the West Coast. Product tankers transport refined products from the Gulf of Mexico to the Atlantic Coast, from the Gulf to the West Coast, and between ports within the West Coast. Tank barges provide coastwise distribution of refined product imports, distribution from pipeline terminals, and inland distribution. In addition, 477 foreign tankers and 64 U.S. flag tankers deliver oil and petroleum products to the United States. They deliver approximately 2.1 million barrels a day, for a total of 770 million barrels a year.

Ships are also used to import liquefied natural gas (LNG). With increasing demand for natural gas for electricity generation, there is a potential for substantial growth in the demand for LNG imports. From 1998 to 1999, the number of LNG carrier arrivals in Boston increased by 350 percent. In addition, mothballed terminals at Elba Island, Georgia, and Cove Point, Maryland, may reinstate LNG imports by 2002.-

Winter storms, extended darkness, and ice formation disrupt barge and tanker movements. The U.S. Coast Guard's fleet of ice breakers has become an important component of the energy infrastructure for the New England, Mid-Atlantic, and Great Lakes regions.

U.S. COAST GUARD



Unlike pipelines, water transportation requires the positioning of vessels to where cargoes are located. For example, it can take three weeks to move a tanker from the Gulf of Mexico to the West Coast. Consequently, tanker markets do not respond quickly to temporary surges in demand, which typically result in price spikes.

Safety

In accordance with the Oil Pollution Act of 1990, a timeline has been established to replace all single-hulled vessels with double-hulled vessels. Many have already been replaced. Modern navigation and port services also help to prevent maritime oil spills. Spill-response technologies and coordinated response plans are key to minimizing damage to property and the environment. Oil spill technology has improved during the last decade and will continue to do so. Risk assessments, preparedness drills, and cleanup strategies are all necessary safeguards for transporting energy goods. As maritime transportation grows, port and waterway infrastructure, as well as the availability of accurate and timely navigation information, will continue to be important for the safe, efficient delivery of energy.

New England's Dependence on Marine Transportation

New England has no refineries, and its small oil pipeline system is not connected to the interstate pipeline system. As a result, New England must rely on tanker and barge shipments of petroleum products from the south as well as direct imports from overseas. There is some question as to whether this distribution system is sufficient to meet the future needs of the region and, if not, what steps need to be taken to ensure future economical, reliable energy supplies.

In recent years, lower national inventories, market forces, and other factors have combined to create much lower inventories for petroleum products such as heating oil in the Northeast. A supply system with less capacity in reserve is more vulnerable to variations in product delivery, and is less capable of absorbing the disruptions in barge and tanker movements that inevitably come

with winter storms, extended darkness, and ice formation. A rapid change to colder weather affects both supply and demand: households need more fuel at the same time that harbors and rivers experience severe ice conditions.

For the New England and Mid-Atlantic seaboard, U.S. Coast Guard icebreakers have become an important component of the infrastructure necessary to provide energy to the region.

The Department of Energy established the Northeast Heating Oil Reserve to ensure heating oil supplies in the region. This emergency buffer can support a shortage for approximately ten days, which is the time required for ships to carry heating oil from the Gulf of Mexico to New York Harbor.

Even with the Reserve in place, marine transportation remains the only source of heating oil for the New England's winter months.

Recommendation:

★ The NEPD Group supports the President's budget proposal to provide \$8 million to maintain the two-million-barrel Northeast Heating Oil Reserve. Operated by the private sector, the Reserve helps ensure adequate supplies of heating oil in the event that colder than normal winters occur in the Northeast United States.

Rail Transportation

Coal, which provides about 52 percent of America's electricity, is the most important single commodity carried by rail. Over the past ten years, the rail share of coal transportation has increased, primarily as a result of increases in low-sulfur western coal, which moves long distances over rail. In 1999, domestic railroads carried 68 percent of the nation's coal, and in 2000, they transported an average of 14.4 million tons of coal a week.

Transportation costs account for 30 to 50 percent of the final delivered price of coal to utilities. About 74 percent of U.S.

low-sulfur coal reserves are located in Montana and Wyoming. Demand for clean coal from Wyoming's Powder River Basin is expected to increase because of its environmental benefits. However, rail capacity problems in the Powder River Basin have created a bottleneck in the coal transportation system.

With little excess capacity in the rail lines supporting the Powder River Basin, expected increases in demand could result in capacity shortfalls and delays in providing coal to power plants that are relying increasingly on "just-in-time" shipments to reduce inventory costs. Additionally, delays in other parts of the rail network, such as at key rail facilities, can undermine the efficiency and reliability of the system. There is a need to eliminate bottlenecks in the coal transportation system.

Infrastructure Security

The energy infrastructure is vulnerable to physical and cyber disruption that could threaten its integrity and safety. Disruptions could come from natural events, like geomagnetic storms and earthquakes, or could come from accidents, equipment failures, or deliberate sabotage. In addition, the nation's transportation and power infrastructures have grown increasingly complex and interdependent. Consequently, any disruption can have extensive consequences.

Transportation facilities have weathered relatively short interruptions in power as a result of natural disasters and accidents, with varying degrees of impact. In a few instances, they have experienced intermittent, lengthy outages that have affected not only primary systems, but integrated services as well, such as voice, data, Internet, and wireless networks that may be used to transmit control information. The growing reliance on computer technologies, automated monitoring and control systems, and electronic commerce makes the system more efficient and vibrant, but also requires a greater level of diligence and use of safeguards.

Accurate weather and climate forecasting can prevent millions of dollars in

damage to U.S. energy infrastructure. For example, the interaction of geomagnetic storms with the Earth's magnetic field can cause additional current to enter transmission lines, which at times has caused regional grid collapse and has destroyed power plant electrical transformers. Given sufficient warning, the industry can initiate protective countermeasures, such as when several northeastern power plants shed 20 percent of their load during a July 2000 geomagnetic storm.

Improvements in forecasting can further assist in the management of energy resources and materials, can prevent power outages in many cases, and can accelerate restoration of power after outages that do occur. Also, data from extreme weather events can be used to design and build infrastructure, such as transmission lines, pipelines, and hydropower dams.

Summary of Recommendations

America's Energy Infrastructure: A Comprehensive Delivery System

- ★ The NEPD Group recommends that the President direct the Secretary of Energy to work with the Federal Energy Regulatory Commission (FERC) to improve the reliability of the interstate transmission system and to develop legislation providing for enforcement by a self-regulatory organization subject to FERC oversight.
- ★ The NEPD Group recommends that the President direct the Secretary of Energy to expand the Department's research and development on transmission reliability and superconductivity.
- ★ The NEPD Group recommends that the President direct the Secretary of Energy to authorize the Western Area Power Administration to explore relieving the "Path 15" bottleneck through transmission expansion financed by nonfederal contributions.
- ★ The NEPD Group recommends that the President direct the appropriate federal agencies to take actions to remove constraints on the interstate transmission grid and allow our nation's electricity supply to meet the growing needs of our economy.
 - Direct the Secretary of Energy, by December 31, 2001, to examine the benefits of establishing a national grid, identify transmission bottlenecks, and identify measures to remove transmission bottlenecks.
 - Direct the Secretary of Energy to work with FERC to relieve transmission constraints by encouraging the use of incentive rate-making proposals.
 - Direct the federal utilities to determine whether transmission expansions are necessary to remove constraints. The Administration should review the Bonneville Power Administration's (BPA's) capital and financing requirements in the context of its membership in a regional RTO, and if additional Treasury financing appears warranted or necessary in the future, the Administration should seek an increase in BPA's borrowing authority at that time.
 - Direct the Secretary of Energy, in consultation with appropriate federal agencies and state and local government officials, to develop legislation to grant authority to obtain rights-of-way for electricity transmission lines, with the goal of creating a reliable national transmission grid. Similar authority already exists for natural gas pipelines in recognition of their role in interstate commerce.

★ The NEPD Group recommends that the President direct the Secretary of the Interior to work with Congress and the State of Alaska to put in place the most expeditious process for renewal of the Trans-Alaskan Pipeline System rights-of-way to ensure that Alaskan oil continues to flow uninterrupted to the West Coast of the United States.

★ The NEPD Group recommends that the President direct the Secretaries of Energy and State, coordinating with the Secretary of the Interior and the Federal Energy Regulatory Commission, to work closely with Canada, the State of Alaska, and all other interested parties to expedite the construction of a pipeline to deliver natural gas to the lower 48 states. This should include proposing to Congress any changes or waivers of law pursuant to the Alaska Natural Gas Transportation Act of 1976 that may be required.

★ The NEPD Group recommends that the President support legislation to improve the safety of natural gas pipelines, protect the environment, strengthen emergency preparedness and inspections and bolster enforcement.

★ The NEPD Group recommends that the President direct agencies to continue their interagency efforts to improve pipeline safety and expedite pipeline permitting in an environmentally sound manner and encourage FERC to consider improvements in the regulatory process governing approval of interstate natural gas pipeline projects.

★ The NEPD Group recommends that the President direct the Administrator of the EPA to study opportunities to maintain or improve the environmental benefits of state and local “boutique” clean fuel programs while exploring ways to increase the flexibility of the fuels distribution infrastructure, improve fungibility, and provide added gasoline market liquidity. In concluding this study, the Administrator shall consult with the Departments of Energy and Agriculture, and other agencies as needed.

★ The NEPD Group recommends that the President direct the Administrator of the Environmental Protection Agency and the Secretary of Energy to take steps to ensure America has adequate refining capacity to meet the needs of consumers.

- Provide more regulatory certainty to refinery owners and streamline the permitting process where possible to ensure that regulatory overlap is limited.
- Adopt comprehensive regulations (covering more than one pollutant and requirement) and consider the rules’ cumulative impacts and benefits.

★ The NEPD Group recommends that the President direct the Administrator of the Environmental Protection Agency, in consultation with the Secretary of Energy and other relevant agencies, to review New Source Review regulations, including administrative interpretation and implementation, and report to the President within 90 days on the impact of the regulations on investment in new utility and refinery generation capacity, energy efficiency, and environmental protection.

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Strengthening Global Alliances

Enhancing National Energy Security and International Relationships

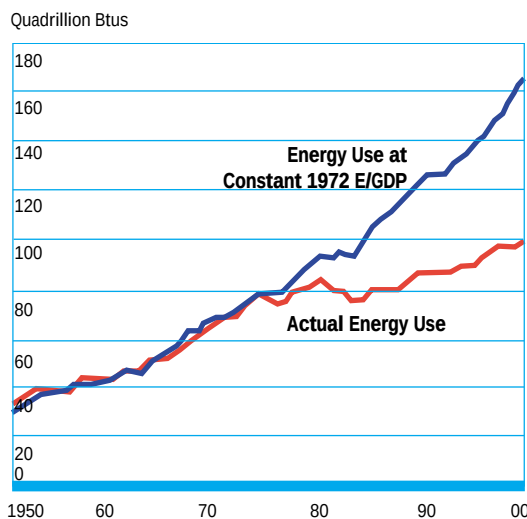
U.S. national energy security depends on sufficient energy supplies to support U.S. and global economic growth. Energy policies that have emphasized reliance on market forces have led to major energy security gains over the past two decades. Major improvements in exploration and production technology, as well as the trend toward opening new areas around the globe for exploration and development, have yielded significant dividends:

- The U.S. and world economies have diversified their sources of oil supplies, largely through increased production in the Western Hemisphere, the North Sea, and Africa.
- The world's fuel mix is also more diverse, primarily because of greater reliance on natural gas and nuclear power.
- The rate of growth in U.S. oil demand has slowed significantly since the first oil shocks of the 1970s because of more energy-efficient industries, structural changes in the economy, and greater efficiencies in vehicles, appliances, and buildings.

Since 1970, as the economy has shifted toward greater use of more efficient technologies, U.S. energy intensity (the amount of energy it takes to produce a dollar of GDP) has declined by 30 percent (Figure 8-1). However, energy use per person in the United States is expected to rise as is overall demand for energy.

Measures to enhance U.S. energy security by meeting this increased demand must begin at home. The first step toward a sound international energy policy is to use our own capability to produce, process, and transport the energy resources we need in an efficient and environmentally sustainable manner. Market solutions to limit the growth in our oil imports would reduce oil consumption for our economy and increase our economic flexibility in responding to any domestic or international disruption of oil or other energy supplies. The United States produces 72 of the 99 quadrillion British thermal units (Btus) of

Figure 8-1
The U.S. Economy is More Energy Efficient (Energy Intensity)
Primary Energy Use



Improvements in energy efficiency since the 1970s have had a major impact in meeting national energy needs relative to new supply. If the intensity of U.S. energy use had remained constant since 1972, consumption would have been about 70 quadrillion Btus (74 percent) higher in 1999 than it actually was.

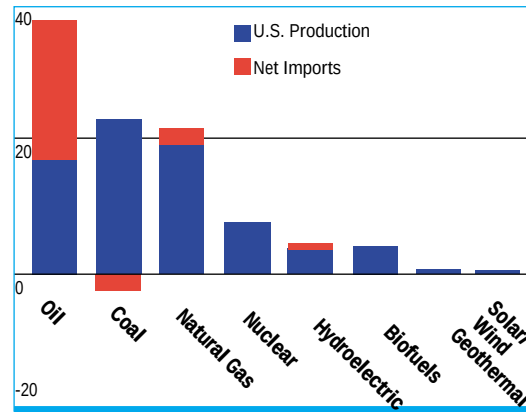
Source: U.S. Department of Energy, Energy Information Administration.



Figure 8-2

Sources of U.S. Fuel Consumption in 1999

(Quadrillion Btus)



The United States produced 72 of the 98 quadrillion Btus of energy that it consumed in 1999. We are self-sufficient in virtually all our energy resources, except oil, of which we import 52 percent of our net requirements, and natural gas, of which we import 15–16 percent net, primarily from Canada.

Source: U.S. Department of Energy, Energy Information Administration.

energy that it consumes (Figure 8-2). We are self-sufficient in virtually all our energy resources except oil, of which we import 52 percent of our net requirements, and natural gas, of which we import 15 to 16 percent of our net requirements, primarily from Canada.

We should not, however, look at energy security in isolation from the rest of the world. In a global energy marketplace, U.S. energy and economic security are directly linked not only to our domestic and international energy supplies, but to those of our trading partners as well. A significant disruption in world oil supplies could adversely affect our economy and our ability to promote key foreign and economic policy objectives, regardless of the level of U.S. dependence on oil imports.

Our energy security also depends on an efficient domestic and international infrastructure to support all segments of the energy supply chain. We can strengthen our own energy security and the shared prosperity of the global economy by working cooperatively with key countries and institutions to expand the sources and types of global energy supplies. We can also advance these goals by increasing the effi

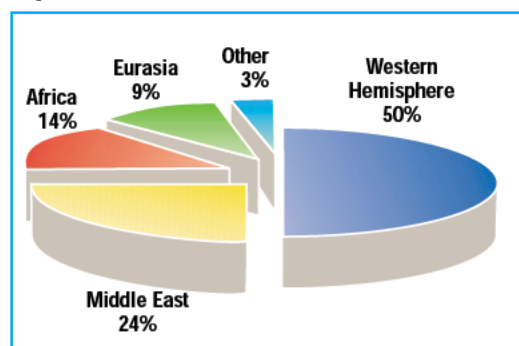
ciency of energy consumption, enhancing the transparency and efficient operation of energy markets, and strengthening our capacity to respond to disruptions of oil supplies. Energy is fundamental to economic growth, and we believe that economic growth and environmental protection can be mutually achieved.

We need to strengthen our trade alliances, to deepen our dialogue with major oil producers, and to work for greater oil production in the Western Hemisphere, Africa, the Caspian, and other regions with abundant oil resources. Greater cooperation with our allies in addressing the growth in oil demand in the transportation sector is particularly important, given the growing demand for oil and other energy resources. Significant economic and environmental benefits can be realized from increased energy efficiency and from the use of clean energy technologies. We need to ensure that our partners in the International Energy Agency (IEA) continue to meet their obligations for emergency supply reserves. Finally, we must continue to work with the IEA, the Asia-Pacific Economic Cooperation (APEC) forum, and others to encourage other large importers to consider measures to augment their oil reserves

Oil Imports and Global Reserves

The U.S. influence on overall world markets is substantial in terms of production and consumption. The United States is the world's second largest natural gas producer and its third largest oil producer. The United States consumes over 25 percent of the oil produced worldwide, slightly more than half of which it imports. Nevertheless, because the price of our domestic and imported oil is determined by a world market, our energy security interests transcend the source of our physical energy supplies (Figure 8-3). Given the large and projected growing volume of U.S. oil imports, our energy and economic security will increase if we take the steps necessary to realize America's potential as a major world oil and natural gas producer.

Figure 8-3
Regional Sources of U.S. Oil Imports in 2000



Slightly over half of the oil the United States imports every day comes from the Western Hemisphere. Canada, Venezuela, and Mexico account for the bulk (41%) of these imports.

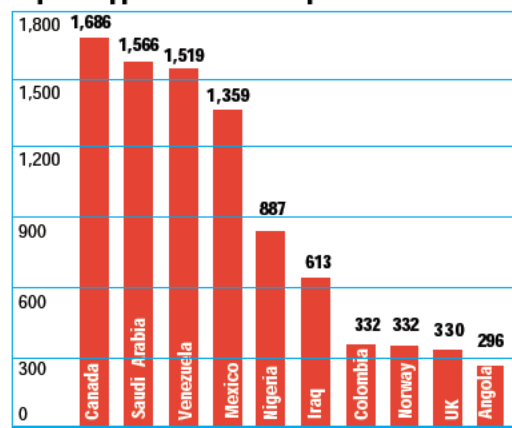
Source: U.S. Department of Energy, Energy Information Administration.

Recommendation:

★ The NEPD Group recommends that the President make energy security a priority of our trade and foreign policy.-

In 2000, nearly 55 percent of U.S. gross oil imports came from four countries: 15 percent from Canada, 14 percent each from Saudi Arabia and Venezuela, and 12 percent from Mexico (Figure 8-4). The security of U.S. energy supply is enhanced by

Figure 8-4
Top 10 Suppliers of U.S. Oil Imports in 2000



In 2000, nearly 55 percent of gross U.S. oil imports came from four leading suppliers: Canada (15%), Saudi Arabia (14%), Venezuela (14%), and Mexico (12%).

Source: U.S. Department of Energy, Energy Information Administration.-

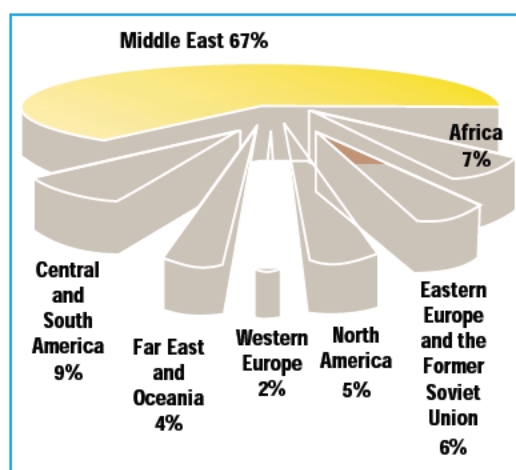
several factors characterizing our diplomatic and economic relationships with our four top suppliers. These factors range from geographic proximity and free trade agreements to integrated pipeline networks, reciprocal energy-sector investments, shared security commitments, and, in all cases, long-term reliable supply relationships (Figure 8-5).

Saudi Arabia and the Middle East Oil Supplies

By 2020, Gulf oil producers are projected to supply between 54 and 67 percent of the world's oil. Thus, the global economy will almost certainly continue to depend on the supply of oil from Organization of Petroleum Exporting Countries (OPEC) members, particularly in the Gulf. This region will remain vital to U.S. interests. Saudi Arabia, the world's largest oil exporter, has been a linchpin of supply reliability to world oil markets.

Saudi Arabia has pursued a policy of investing in spare oil production capacity, diversifying export routes to both of its coasts, and providing effective assurances that it will use its capacity to mitigate the

Figure 8-5
Proven World Oil Reserves in January 2000



The world's proven crude oil reserves remain relatively concentrated. The Middle East holds 664 billion barrels, or roughly two-thirds of the world's conventional oil reserves, followed by the Western Hemisphere (14%) and Africa (7%).

Source: U.S. Department of Energy, Energy Information Administration.

Saudi Arabia has pursued a policy of investing in spare oil production capacity, diversifying export routes to both of its coasts, and providing effective assurances that it will use its capacity to mitigate the impact of oil supply disruptions in any region.

ARAMCO

impact of oil supply disruptions in any region (Figure 8-6). Algeria, Kuwait, Oman, Qatar, Saudi Arabia, the United Arab Emirates (UAE), Yemen, and other states in the region with which we maintain diplomatic relations have all, to some extent, opened their energy sectors to international investment. This development provides an important opportunity to further encourage foreign investment in these important energy-producing countries, thereby broadening our shared commercial and strategic interests. By any estimation, Middle East oil producers will remain central to world oil security. The Gulf will be a primary focus of U.S.

international energy policy, but our engagement will be global, spotlighting existing and emerging regions that will have a major impact on the global energy balance.

Recommendation:

★ The NEPD Group recommends that the President support initiatives by Saudi Arabia, Kuwait, Algeria, Qatar, the UAE, and other suppliers to open up areas of their energy sectors to foreign investment.

Improving Market Transparency

The United States must work with oil producers to improve the transparency, timeliness, and accuracy of the data that guide global oil markets. A lack of timely and accurate data relating to both oil production and inventory levels has contributed to the price volatility witnessed in 2000. Discussions among the major oil producers and consumer countries should be designed to improve the transparency, accuracy, and timeliness of data that guide the market. In turn, enhanced data quality and increased data transparency will improve market efficiency. Refocusing that dialogue beyond short-term market developments to long-term issues of world economic growth, improving data quality, and addressing energy infrastructure is needed to maintain a smooth flow of energy from the wellhead to the consumer.

Recommendation:

★ The NEPD Group recommends that the President direct the Secretaries of State, Energy and Commerce work to improve dialogue among energy producing and consuming nations.

Promoting International Trade and Investment

Longstanding U.S. policy supports a liberalized global energy sector that is open to international trade and investment. The United States benefits from international investments at home that have increased our



Figure 8-6
Saudi Arabia Export Pipelines



Saudi Arabia, the world's largest oil supplier, maintains major oil export ports and storage capacity on both the Gulf and the Red Sea.

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energy sector's capacity and its infrastructure. Both producers and consumers will benefit from ensuring that the global energy infrastructure is sufficient and flexible to meet growing global demand.

American energy firms remain world leaders, and their investments in energy producing countries enhance efficiencies and market linkages while increasing environmental protections. Expanded trade and investment between oil importing and exporting nations can increase shared interests while enhancing global energy and economic security. Promoting such investment will be a core element of our engagement with major foreign oil producers.

Recommendations:

★ The NEPD Group recommends that the President direct the Secretaries of State, Commerce and Energy to continue supporting American energy firms competing in markets abroad and use our membership in multilateral organizations, such as the Asia-Pacific Economic Cooperation (APEC) forum, the Organization for Economic Cooperation and Development (OECD), the World Trade Organization (WTO) Energy Services Negotiations, the Free Trade Area of the Americas (FTAA), and our bilateral relationships to implement a system of clear, open, and transparent rules and procedures governing foreign investment; to level the playing field for U.S. companies overseas; and to reduce barriers to trade and investment.

★ The NEPD Group recommends that the President direct the Secretaries of Commerce and Energy, and the U.S. Trade Representative, to support a sectoral trade initiative to expand investment and trade in energy-related goods and services that will enhance exploration, production, and refining, as well as the development of new technologies.

Reviewing and Reforming Sanctions

Economic sanctions include U.S. unilateral sanctions as well as multilateral sanctions, such as United Nations (UN) Security Council Resolutions. Sanctions can advance important national and global security objectives and can be an important foreign policy tool, especially against nations that support terrorism or seek to acquire weapons of mass destruction. Nevertheless, sanctions should be periodically reviewed to ensure their continued effectiveness and to minimize their costs on U.S. citizens and interests.

Recommendation:

★ The NEPD Group recommends that the President direct the Secretaries of State, Treasury, and Commerce to initiate a comprehensive review of sanctions. Energy security should be one of the factors considered in such a review.-

Diversity of Supply

Concentration of world oil production in any one region of the world is a potential contributor to market instability, benefiting neither oil producers nor consumers. Periodic efforts by OPEC to maintain oil prices above levels dictated by market forces have increased price volatility and prices paid by consumers, and have worked against the shared interests of both producers and consumers in greater oil market stability. This remains a policy challenge, which we will meet over the longer term through a comprehensive energy policy that addresses both supply and demand, as well as through increased engagement with all our major suppliers. Greater diversity of world oil production remains important.

Encouraging greater diversity of oil production and, as appropriate, transportation, within and among geographic regions has obvious benefits to all market participants. Technological advances will enable the United States to accelerate the diversification of oil supplies, notably through deep-



The United States is helping developing countries use energy efficient technologies. Photovoltaic-powered pumps are being used in many wells throughout rural India for collecting potable water.

U.S. DEPARTMENT OF ENERGY, NATIONAL RENEWABLE ENERGY LABORATORY

water offshore exploration and production in the Atlantic Basin, stretching from off shore Canada to the Caribbean, Brazil, and West Africa. The Caspian Sea can also be a rapidly growing new area of supply.

The ongoing development of so-called “heavy oil” reserves in the Western Hemisphere is an important factor that promises to significantly enhance global oil reserves and production diversity. Recent Canadian and Venezuelan success in making heavy oil deposits commercially viable suggests that they will contribute substantially to the diversity of global energy supply, and to our own energy supply mix over the medium to long term. Leading non-OPEC oil exporters, such as Mexico and Norway, remain critical to the diversity of global energy supply.

Growing levels of conventional and heavy oil production and exports from the Western Hemisphere, the Caspian, and Africa are important factors that can lessen the impact of a supply disruption on the U.S. and world economies. Overall U.S. policies in each of these high-priority regions will focus on improving the investment climate and facilitating the flow of needed investment and technology.

Bilateral energy working groups, such as the U.S.-Kazakhstan Oil, Gas and Commercial Energy Working Group and the U.S.-Russian Oil and Gas Working Group, can improve the trade climate in high-priority countries. In addition to seeking new sources of oil, the United States is helping developing countries use energy efficient technologies to mitigate the environmental impacts of energy use, and to improve access to energy resources.

WTO members are beginning to examine global trade in energy services. The United States has called on WTO members to open markets eligible for private participation in the entire range of energy services, from exploration to the final customer. The energy service proposal would attempt to ensure nondiscriminatory access to foreign providers of energy services. Equally important, the U.S. proposal suggests that WTO members consider how to best create a pro-competitive regulatory en-

Figure 8-7

Canada–U.S. Natural Gas Pipelines: 2001



Canada–U.S. Oil Pipelines: 2001

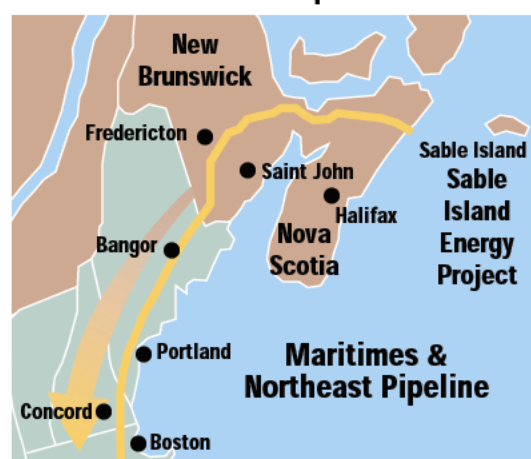


An integrated network of oil and gas pipelines demonstrates the seamless nature of North American energy trade.

Sources: Lakehead Pipe Line Company, Inc., and Canadian Association of Petroleum Producers.

Figure 8-8

Maritimes and Northeast Pipeline: 2000



New England's geography made it the “last stop” for natural gas pipelines stretching thousands of miles across the continent from the South and the West. Consequently, the region became the most oil-dependent area in the country, particularly for home heating and electricity. With the January 1, 2000, inauguration of Atlantic Canada's Maritimes and Northeast Pipeline, New England is now at the beginning of the line for natural gas flowing across the border from Canada at Calais, Maine. Overall, the region's fuel mix is becoming increasingly diversified, with natural gas demand slated to increase by 2.4 percent a year through 2020.

Source: Maritimes and NorthEast Pipeline.

environment for energy services, so that opaque or discriminatory regulatory practices do not undermine commitments to open their domestic markets to foreign service providers. Such objectives can also be pursued in the FTAA and APEC.

Toward a North American Energy Framework

Increased U.S., Canadian, and Mexican energy production and cooperation would enhance energy security and, through our economic links in the North America Free Trade Agreement (NAFTA) economy, fundamentally advance each country's economic security. As state and federal governments consider energy reforms, there will be a need to ensure compatible regulatory frameworks with our neighbors while recognizing differences in jurisdictions.

Canada

Canada's deregulated energy sector has become America's largest overall energy trading partner, and our leading foreign supplier of natural gas, oil, and electricity. Canada's sustainable development based energy strategies contribute to the health of the NAFTA economy and of our shared environment.

Canada provided 14 percent of U.S. natural gas supply last year. An integrated network of pipelines demonstrates the seamless nature of North American energy trade (Figure 8-7). Estimated natural gas deposits in Alaska and Northwest Canada exceed 70 trillion cubic feet, representing over three years of total U.S. consumption at present levels.

To advance shared economic and environmental objectives, the private sector is poised to develop the continent's northern gas reserves, with pipeline linkages between both countries. To the east, recent development of Canada's Atlantic offshore energy reserves has made significant strides, with major offshore natural gas and oil production now available. Canada's Atlantic energy development is now providing previously untapped sources of clean-burning natural gas not only to Nova Scotia and New Brunswick but also to heating oil-de-



pendent New England (Figure 8-8).

Our large cross-border electricity trade flows in each direction. Our electricity imports from Canada are derived largely from hydropower produced in eastern Canada, Canadian and American hydropower projects in the Pacific Northwest operating pursuant to the Columbia River Treaty, and a nuclear power plant in New Brunswick. All of these sources provide important trade and clean air benefits, while allowing both countries to benefit from load sharing and integration. The reliability of the North American electricity grid can be enhanced yet further through closer coordination and compatible regulatory and jurisdictional approaches.

Canada's oil trade, responding to market signals, increased 4 percent worldwide and 10 percent with the United States last year. Estimates of Canada's recoverable heavy oil sands reserves are substantial, and new technologies are being deployed to develop their potential. Production from these promising areas now approaches 600,000 barrels a day. Their continued development can be a pillar of sustained North American energy and economic security.

Mexico

Our energy relationship with Mexico reflects the increasingly interrelated character of NAFTA economies and our contiguous border. U.S. natural gas reserves, pipe-

Offshore oil platform near Campeche, Mexico. Mexico's large crude oil reserves—approximately 25 percent larger than our own proven reserves—makes it a likely source of increased oil production over the next decade.

U.S. EMBASSY, MEXICO CITY

Figure 8-9

Mexican Oil and Gas Resources: 2001



Mexico's large oil reserves—approximately 25 percent larger than U.S. proven reserves—make it a likely source of increased oil production over the next decade.

Source: U.S. Central Intelligence Agency.

A carrier transports liquefied natural gas (LNG) from Trinidad and Tobago—our largest LNG supplier—to Boston harbor. LNG currently represents 16 percent of New England's natural gas supply.

CAROT LNG

lines, and industries are closer to the growing border area than some of Mexico's reserves. The United States is a net exporter of refined petroleum products and natural gas to Mexico, primarily through pipeline connections to northern Mexico. Mexico is a leading and reliable source of imported oil, and its large reserve base, approximately 25 percent larger than our own proven reserves, makes Mexico a likely source of increased oil production over the

next decade (Figure 8-9).

Mexico began exporting 50 megawatts of electricity from Baja to California in January 2001. However, the transmission infrastructure on both sides of the border is insufficient for greater flows of energy in either direction without expansion. In the United States, our process for "Presidential Permitting" of cross-border infrastructure linkages needs to be updated and streamlined.

Mexico will make its own sovereign decisions on the breadth, pace, and extent to which it will expand and reform its electricity and oil and gas capacities. Where the country has opened its energy sector to private investment, such as in natural gas transmission, distribution, and storage, investments have been made to our mutual benefit. To the extent Mexico seeks to attract additional foreign investment consistent with its Constitution, which reserves exploration and production rights to the Mexican government, the United States should actively encourage the U.S. private sector to consider market-based investments.

Recommendations:

★ The NEPD Group recommends that the President direct the Secretaries of State, Commerce, and Energy to engage in a dialogue through the North American Energy Working Group to develop closer energy integration among Canada, Mexico, and the United States and identify areas of cooperation, fully consistent with the countries' respective sovereignties.

★ The NEPD Group recommends that the President direct the Secretaries of Energy and State, in consultation with the Federal Energy Regulatory Commission, to review their respective oil, natural gas, and electricity cross boundary "Presidential Permitting" authorities, and to propose reforms as necessary in order to make their own regulatory regimes more compatible for cross-border trade.



★ The NEPD Group recommends that the President direct the Secretaries of Energy and State, coordinating with the Secretary of the Interior and the Federal Energy Regulatory Commission, to work closely with Canada, the State of Alaska, and all other interested parties to expedite the construction of a pipeline to deliver natural gas to the lower 48 states. This should include proposing to Congress any changes or waivers of law pursuant to the Alaska Natural Gas Transportation Act of 1976 that may be required.

South America: Latin America and the Caribbean

Latin America and the Caribbean are growing not only as major producing regions, but also as major consumers of oil and natural gas. Trinidad and Tobago's progressive investment code has made it the hemisphere's largest exporter of LNG and the largest supplier of LNG to the United States in 2000. Unprecedented development of Central and South America's vast natural gas reserves—222.7 trillion cubic feet as of January 2000, illustrated by transcontinental pipelines linking Bolivia, Brazil, Argentina, Chile, Paraguay, and Uruguay—increase regional self-reliance, affirm economic integration, aid the environment, and stem the growth in oil demand. Colombia has also become an important supplier of oil to the United States.

The United States, with Venezuela, is a co-coordinator of the Hemispheric Energy Initiative process. In March 2001, a Summit of the Americas Hemispheric Energy Ministerial meeting was hosted by the Government of Mexico. At the meeting, the region's energy ministers pledged to support integration and sustainable development in the hemisphere, recognizing the need to foster stable and transparent regulatory frameworks. In April 2001, the thirty-four democratically elected leaders of the Western Hemisphere met in Quebec City for the Third Summit of the Americas. They called for a renewed effort to strengthen the hemisphere's energy cooperation and integration.



Venezuela is the world's fifth largest oil exporter, and the third largest oil supplier to the United States. Its energy industry is increasingly integrated into the U.S. marketplace. Venezuela's downstream investments in the United States make it a leading refiner and gasoline marketer here. Growing U.S. and international investments in Venezuela's energy sector, particularly in its resource-rich heavy oil sector, are enhancing the country's ability to meet its development goals and to keep pace with a growing world energy marketplace. Venezuela is also moving to liberalize its natural gas sector, which will increase opportunities for foreign investment to expand Venezuelan natural gas production. These positive steps along with conclusion of a Bilateral Investment Treaty, which is now being negotiated, would provide investors from both the United States and Venezuela incentives for increased investment.

Brazil has long been a pioneer in the development of deep-water offshore oil and gas resources. Its world-class oil industry is now moving to become a partner with U.S. and international investors to more fully develop its prolific offshore oil reserves. This welcome development will enhance hemispheric energy production from well-established sedimentary basins.

U.S. Secretary of Energy Spencer Abraham listens to his colleagues at the Summit of the Americas Hemispheric Energy Ministerial meeting in Mexico City on March 9, 2001.

U.S. EMBASSY, MEXICO CITY

Recommendations:

- ★ The NEPD Group recommends that the President direct the Secretaries of State and Commerce to conclude negotiations with Venezuela on a Bilateral Investment Treaty, and propose formal energy consultations with Brazil, to improve the energy investment climate for the growing level of energy investment flows between the United States and each of these countries.
- ★ The NEPD Group recommends that the President direct the Secretaries of Energy, Commerce, and State to work through the Summit of the Americas Hemispheric Energy Initiative to develop effective and stable regulatory frameworks and foster reliable supply sources of all fuels within the region.

Africa

Sub-Saharan Africa holds 7 percent of world oil reserves and comprises 11 percent of world oil production. Along with Latin America, West Africa is expected to be one of fastest-growing sources of oil and gas for the American market. African oil tends to be of high quality and low in sulfur, making it suitable for stringent refined product requirements, and giving it a growing market share for refining centers on the East Coast of the United States.

In 2000, OPEC member Nigeria exported an average of 900,000 barrels of oil per day to the United States, out of its total production of 2.1 million barrels of oil per day. Nigeria, in partnership with the private sector, has set ambitious production goals as high as 5 million barrels of oil per day over the coming decade.

Angola's growing offshore oil industry, with participation by U.S. and international oil firms, is also a major source of growth. In 2000, Angola exported 300,000 barrels of oil per day out of its 750,000 barrels of oil per day of total production to the United States, and is thought to have the potential to double its exports over the next ten years. Other significant exporters to the United States included Gabon and the Congo-Brazzaville.

The World Bank has supported Chad's efforts to begin ambitious oil development. This year an international consortium that includes U.S. firms began investing \$3.5 billion in this pipeline from Chad to Cameroon, the largest infrastructure project in Africa to day. When complete, the pipeline will allow Chad to export up to 250,000 barrels of oil per day.

The U.S. Agency for International Development (USAID) has provided technical assistance in support of a West Africa Power Pool and associated pipeline project involving a number of U.S. oil companies, and is providing assistance for the creation of a regional regulatory framework that will enable Ghana and Nigeria to become major exporters of natural gas and electricity.

The West Africa Gas Pipeline is a 161 mile (1,000-kilometer), \$400 million on shore/offshore natural gas pipeline connecting Nigeria with Benin, Togo, and Ghana. The pipeline is being built by a consortium of companies, and includes financing by the U.S. Export-Import Bank.

Recommendations:

- ★ The NEPD Group recommends that the President direct the Secretaries of State, Energy, and Commerce to rein-vigorate the U.S.-Africa Trade and Economic Cooperation Forum and the U.S.-African Energy Ministerial process; deepen bilateral and multilateral engagement to promote a more receptive environment for U.S. oil and gas trade, investment, and operations; and promote geographic diversification of energy supplies, addressing such issues as transparency, sanctity of contracts, and security.
- ★ The NEPD Group recommends that the President direct the Secretaries of State, Energy, and Commerce to recast the Joint Economic Partnership Committee with Nigeria to improve the climate for U.S. oil and gas trade, investment, and operations and to advance our shared energy interests.
- ★ The NEPD Group recommends that the President direct the Secretaries of

State, Energy, and Commerce to support more transparent, accountable, and responsible use of oil resources in African producer countries to enhance the stability and security of trade and investment environments.

The Caspian

Proven oil reserves in Azerbaijan and Kazakhstan are about 20 billion barrels, a little more than the North Sea and slightly less than the United States. Exploration, however, is continuing, and proven reserves are expected to increase significantly.

For example, initial results of the exploration well at Kazakhstan's Kashagan field indicate the find is one of the most important in thirty years, and is comparable to Prudhoe Bay in size. Current exports from the region are only about 800,000 barrels of oil per day, in part due to limited export route options. However, potential exports could increase by 1.8 million barrels of oil per day by 2005, as the United States works closely with private companies and countries in the region to develop commercially viable export routes, such as the Baku-Tbilisi-Ceyhan (BTC) and Caspian Pipeline Consortium oil pipelines (Figure 8 10). Moreover, there is considerable optimism that exports could grow even more substantially in subsequent years because of positive prospects for new oil and gas finds as additional geologic structures undergo exploration, and the development of new export routes.

Foreign investors and technology are critical to rapid development of new commercially viable export routes. Such development will ensure that rising Caspian oil production is effectively integrated into world oil trade. U.S.-supported East-West pipeline routes will add substantial new oil transportation capacity to allow continued expansion of production and exports. Over land routes via pipeline, such as the planned BTC oil pipeline, will also help mitigate maritime risks in the crowded Bosphorus Straits. To help countries prepare for increased oil production within the re-

Figure 8-10

Caspian Energy Export Pipelines: 2001



Several oil and natural gas pipeline projects are proposed for the Caspian area.

Source: U.S. Central Intelligence Agency.

gion, the United States is working with Black Sea and Caspian Sea border states to ensure that they develop adequate oil spill response capabilities.

Recommendations:

- ★ The NEPD Group recommends that the President direct the Secretaries of State, Commerce, and Energy to support the BTC oil pipeline as it demonstrates its commercial viability.-
- ★ The NEPD Group recommends that the President direct the Secretaries of Commerce, State, and Energy to continue working with relevant companies and countries to establish the commercial conditions that will allow oil companies operating in Kazakhstan the option of exporting their oil via the BTC pipeline.-
- ★ The NEPD Group recommends that the President direct the Secretaries of State, Commerce, and Energy to support the efforts of private investors and regional governments to develop the Shah Deniz gas pipeline as a way to help Turkey and Georgia diversify their natural gas supplies and help Azerbaijan export its gas via a pipeline that will continue diversification of secure energy supply routes.-
- ★ The NEPD Group recommends that the President direct appropriate federal agencies to complete the current cycle of oil spill response readiness workshops and to consider further appropriate steps to ensure the implementation of the workshops' recommendations.-
- ★ The NEPD Group recommends that the President direct the Secretary of State to encourage Greece and Turkey to link their gas pipeline systems to allow European consumers to diversify their gas supplies by purchasing Caspian gas.-
- ★ The NEPD Group recommends that the President direct the Secretaries of Commerce, Energy, and State to deepen their commercial dialogue with Kazakhstan, Azerbaijan, and other Caspian states to provide a strong, transparent, and stable business climate for energy and related infrastructure projects.-

Russia

Russia has about 5 percent of the world's proven oil reserves. In 2000, Russia produced an average of 6.7 million barrels of oil and natural gas liquids per day, making it both the world's third largest producer and second largest exporter at 4.2 million barrels of oil per day. Russia's oil production in 2000 represented an increase of 7 percent over 1999, the first increase since the dissolution of the Soviet Union. A similar rate of increase is projected for 2001. New fields are being developed, including those with U.S. and other foreign investors.

Nevertheless, substantial infrastructure investment is still needed, as well as legislation and a stable and reliable regime of contracting to finalize the Production Sharing Agreement (PSA) mechanism for private-sector participation and actions to improve the general investment climate. Russian oil firms are increasingly active on a global scale, with upstream and downstream investments in the Caspian, the United States, Africa, South Asia, and Europe, enhancing Russia's ability to develop its own and international oil reserves.

Russia holds 33 percent of the world's natural gas reserves, exporting a full 35 percent of its production to Europe and Central Asia in 1999. Russian natural gas exports can increase regional fuel diversification and advance environmental goals. With production declines now evident in existing fields, development of new reserves that require substantial new investments will be necessary.

Recommendations:

- ★ The NEPD Group recommends that the President direct the Secretaries of State, Commerce, and Energy to deepen the focus of the discussions with Russia on energy and the investment climate.-
- ★ The NEPD Group recommends that the President direct the Secretaries of Commerce, State, and Energy to assist U.S. companies in their dialogue on the investment and trade climate with-

Russian officials, to encourage reform of the PSA law and other regulations and related tax provisions, as well as general improvements in the overall investment climate. This will help expand private investment opportunities in Russia and will increase the international role of Russian firms.

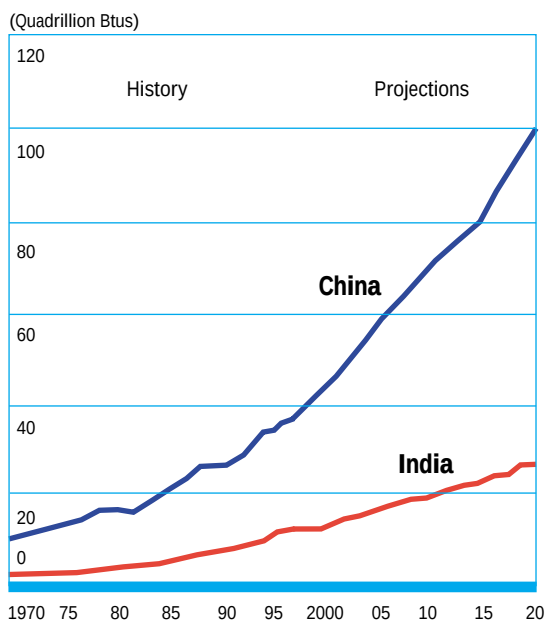
Asia

Asia holds less than 5 percent of world proven oil reserves, but accounts for more than 10 percent of oil production and about 30 percent of world oil consumption. The developing countries of the Pacific Rim are expected to increase their total petroleum imports by almost 43 percent between 1997 and 2020. The developing countries of Asia are expected to remain heavily dependent on Middle East imports.

China is a critical player in global energy security issues, since its net oil imports are expected to rise from approximately 1 million barrels of oil per day at present to possibly 5 to 8 million barrels of oil per day by 2020, with a predominant (over 70 percent) dependence on Middle East imports. China moved in the mid-1990s from being a net oil exporter to a net oil importer.

About 7 percent of the world's proven natural gas reserves are located in Asia. Asian gas production represents about 11 percent of the world total, and consumption is less than 3 percent of world natural gas demand. Other natural gas producers, such as Malaysia, Myanmar, and Australia, are net gas exporters. Currently Japan, South Korea, and Taiwan are the major gas importers in Asia. China, in addition to accelerating domestic exploration and development of natural gas resources, is planning to import gas via pipeline from Central Asia. India, likewise, is considering several potential LNG import projects (Figure 8-11).

Figure 8-11
Energy Consumption in China and India: 1970–2020



China and India account for the bulk of projected growth in oil demand in non-OECD countries.

Source: U.S. Department of Energy, Energy Information Administration.

Recommendations:

- ★ The NEPD Group recommends that the President direct the Secretaries of State, Commerce, and Energy to continue to work in the APEC Energy-Working Group to examine oil market-data transparency issues and the variety of ways petroleum stocks can be used as an option to address oil market disruptions.-
- ★ The NEPD Group recommends that the President direct the Secretaries of State and Energy to work with India's Ministry of Petroleum and Natural Gas to help India maximize its domestic oil and gas production.-

Diversification of Fuel Mix

The growing demand for more fuel efficient technologies offers U.S. businesses significant trade and investment opportunities overseas, while addressing rising world oil demand. The United States supports a practical, market-based approach that en

courages the adoption of efficient technologies, including those relating to natural gas, nuclear energy, and renewable energy. This approach takes into account existing national and international programs and has the potential to energize both public action and private involvement. Introduction of these technologies abroad also supports U.S. national interests by reducing competition for the oil resources on which the global economy continues to rely. Overall, the U.S. government's goal is to adopt policies that support innovative finance and market mechanisms that will provide U.S. businesses and consumers greater incentives to make more cost effective, energy efficient investment and consumption decisions.

Increased use of renewable energy technologies would improve U.S. energy security, yield global environmental benefits, improve social and economic stability in the developing world, and provide significant trade and investment opportunities to U.S. businesses. Promotion of clean energy technology exports can mitigate international dependence on oil supplies from volatile regions, help lower energy costs for U.S. consumers, bring U.S. firms greater access to large foreign markets, and enhance U.S. integration with global sources of innovation. In consultation with U.S. industry, the U.S. government is participating in efforts of the IEA, the G-8, the OECD, the United Nations, and multilateral development banks to formulate effective strategies for accelerated market penetration of renewable energy technologies. Significant market penetration will depend on further reducing the costs of deploying these technologies.

The Clean Energy Technology Exports Working Group, a Federal interagency task force comprised of USAID and the Departments of Commerce and Energy, is creating a strategic plan that will provide a roadmap for future exports of U.S. clean energy technologies. Through its international trade programs, the Department of Commerce will showcase market-ready U.S. technologies that generate a cleaner environment and increase energy efficiency.

Recommendation:

★ The NEPD Group recommends that the President direct the Secretaries of Commerce, State, and Energy to promote market-based solutions to environmental concerns; support exports of U.S. clean energy technologies and encourage their overseas development; engage bilaterally and multilaterally to promote best practices; explore collaborative international basic research and development in energy alternatives and energy efficient technologies; and explore innovative programs to support the global adoption of these technologies.

Climate Change

The President is committed to addressing the issue of global climate change in a manner that protects our environment and economy. Toward this end, the Administration is undertaking a Cabinet-level review of domestic and international policies for addressing this issue.

The United States invited other nations to re-examine global climate change issues, including technologies and market-based systems. Increasing our understanding of the most recent science and further research into the science of climate change will be essential to developing the optimal strategy.

There is increasing awareness of global competition for fossil fuels and their potential threats to the global environment. The United States can diminish both risks by becoming more energy efficient at home, by working with other nations, and by encouraging developing countries to use the cleanest and most energy-efficient technologies. Through educational programs, the United States can encourage developing countries to use advanced U.S. energy technologies, energy management practices, and market-based policies. The United States is uniquely positioned to help emerging nations build energy and institutional capacity and to finance energy-related activities and services. Doing so could prove to be a cost effective investment, for both the United States and emerging economies.

Recommendation:

★ The NEPD Group recommends that the President direct federal agencies to support continued research into global climate change; continue efforts to identify environmentally and cost-effective ways to use market mechanisms and incentives; continue development of new technologies; and cooperate with allies, including through international processes, to develop technologies, market-based incentives, and other innovative approaches to address the issue of global climate change.

Oil Consumption

Although U.S. energy security can be reinforced by domestic efforts to enhance supply and use energy more efficiently, growth in international oil demand will exert increasing pressure on global oil availability. Worldwide oil consumption is projected to grow by 2.1 percent a year over the next two decades. However, oil demand is projected to grow three times as fast in non-OECD countries as in OECD countries, which will increase worldwide competition for global oil supplies and put increased pressure on our shared environment. Accordingly, non-OECD countries' share of oil demand is expected to rise from 41 percent to 52 percent (Figure 8-12). China and India will be major contributors to this growth in demand and will rely heavily on imports to meet their needs. This growth will increase the stake that many developing countries have in ensuring access to significant energy resources, as well as their incentive to pursue energy efficiency.

Transportation has been responsible for nearly all the growth in OECD oil consumption over the last twenty years, and is projected to be the leading source of future growth in oil consumption through 2020. Transportation-related fuel consumption in the developing world is expected to more than double by 2020, growing at an annual average rate of 4 percent. Therefore, both OECD and developing countries will need

to increase their focus on efficiencies in the transportation sector. The momentum to create market mechanisms supporting alternative-fuel vehicles will increase. Best practices that seek to reduce the cost of these technologies and to promote market penetration should be pursued. Without additional efforts to reduce this growth in consumption, the transportation sector's fuel needs will force an increasing dependence on oil in the developed and developing worlds.

Recommendations:

★ The NEPD Group recommends that the President seek to increase international cooperation on finding alternatives to oil, especially for the transportation sector.-

★ The NEPD Group recommends that the President direct the Secretary of State to reinvigorate its dialogue with the European Union on energy issues, and resume the consultative process this year in Washington.-

★ The NEPD Group recommends that the President promote a coordinated approach to energy security by calling for an annual meeting of G-8 Energy Ministers or their equivalents.-

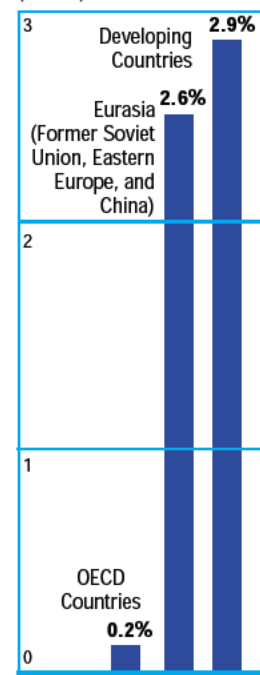
Emergency Preparedness for Oil Supply Disruption

U.S. and world exposure to oil supply disruptions increases as the size of strategic and commercial stocks relative to demand declines. This vulnerability is a result of rising global demand, tight supplies, and inadequate efforts to establish or expand oil stockpiles. Such a situation magnifies the importance of U.S. coordination with other members of the IEA, comprised of most OECD member governments. Each IEA member that is a net oil importer is required to hold stocks equal to 90 days or more of its net imports. The IEA maintains agreed mechanisms for coordinating the use of these stocks in responding to a physical supply disruption. Collectively, the net oil-importing members of the IEA currently hold

Figure 8-12

Projected Oil Consumption Rates in Three Economic Regions: 1999–2020

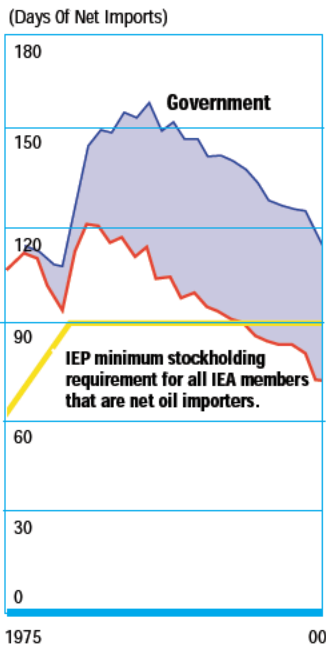
(Percent)



Over the next two decades, oil consumption in developing countries and Eurasia will grow three times faster than in the rest of the world.

Source: U.S. Department of Energy, Energy Information Administration.

Figure 8-13
**Stocks of IEA Net Importers:
 1975–2000**



The International Energy Agency, of which the United States is a member, closely tracks the amount of strategic and commercial petroleum stocks maintained by its member states. The International Energy Program (IEP) Agreement "binds Participating Countries to make specific measures to meet any oil supply emergency and, over the long term, to reduce dependence on oil."

Source: International Energy Agency.

approximately 113 days worth of strategic and commercial stocks. U.S. stocks, which include both government and commercial stocks, are slightly above the IEA average. While this is more than required, it is far below the peak coverage of 157 days reached in 1986. Moreover, several member states have fallen below the 90-day threshold (Figure 8-13).

The United States meets part of its IEA obligation through government-owned stocks held in the U.S. Strategic Petroleum Reserve (SPR). The SPR currently holds 541 million barrels of oil, which is enough to cover the loss of all U.S. imports for 54 days or a partial disruption for much longer. Close to 33 million barrels of oil will be deposited in the SPR by the fourth quarter of 2002, returning oil that had been "exchanged" out of the reserve last year. SPR oil can be withdrawn at a maximum rate of over 4 million barrels of oil per day initially and could reach the market within fifteen days of a Presidential directive. Because of increased net oil imports, the days of oil import coverage provided by the SPR have declined considerably over the past decade. In 1990, the SPR contained enough oil to compensate for the loss of 82 days worth of U.S. imports—substantially more than today's 54-day supply. As domestic production and import patterns evolve, the Administration will work to inform Congress about changing coverage levels provided by the SPR. It should be noted that the United States also counts on the SPR as a national defense fuel reserve.

The oil market's day-to-day operation and its ability to respond to supply problems depend heavily on the availability of information on supply, demand, and price. The oil market volatility of the past two years has emphasized the need for more comprehensive and timely oil market information.

Recommendations:

- ★ The NEPD Group recommends that the President reaffirm that the SPR is designed for addressing an imminent or actual disruption in oil supplies, and not for managing prices.
- ★ The NEPD Group recommend that the President direct the Secretary of Energy to work within the International Energy Agency (IEA) to ensure that member states fulfill their stock holding.
- ★ The NEPD Group recommends that the President direct the Secretary of Energy to encourage major oil-consuming countries that are not IEA members to consider strategic stocks as an option for addressing potential supply disruptions. In this regard, we should work closely with Asian economies, especially through APEC.
- ★ The NEPD Group recommends that the President direct the Secretary of Energy offer to lease excess SPR storage facilities to countries (both IEA and non-IEA members) that might not otherwise build storage facilities or hold sufficient strategic stocks, consistent with statutory authorities.
- ★ The NEPD Group recommends that the President, at such time that exchanged SPR barrels are returned to the SPR, should determine whether offshore Gulf of Mexico royalty oil deposits to the SPR should be resumed, thereby increasing the size of our reserve.
- ★ The NEPD Group recommends that the President direct the Secretary of Energy to work closely with Congress to ensure that our SPR protection is maintained.
- ★ The NEPD Group recommends that the President direct the Secretary of Energy to work with producer and consumer country allies and the IEA to craft a more comprehensive and timely world oil data reporting system.

Summary of Recommendations

Strengthening Global Alliances: Enhancing National Energy Security and International Relationships

- ★ The NEPD Group recommends that the President make energy security a priority of our trade and foreign policy.
- ★ The NEPD Group recommends the President support initiatives by Saudi Arabia, Kuwait, Algeria, Qatar, the UAE, and other suppliers to open up areas of their energy sectors to foreign investment.
- ★ The NEPD Group recommends that the President direct the Secretaries of State, Energy and Commerce work to improve dialogue among energy producing and consuming nations.
- ★ The NEPD Group recommends that the President direct the Secretaries of State, Commerce, and Energy to continue supporting American energy firms competing in markets abroad and use our membership in multilateral organizations, such as the Asia-Pacific Economic Cooperation (APEC) forum, the Organization for Economic Cooperation and Development (OECD), the World Trade Organization (WTO) Energy Services Negotiations, the Free Trade Area of the Americas (FTAA), and our bilateral relationships to implement a system of clear, open, and transparent rules and procedures governing foreign investment; to level the playing field for U.S. companies overseas; and to reduce barriers to trade and investment.
- ★ The NEPD Group recommends that the President direct the Secretaries of Commerce and Energy, and the U.S. Trade Representative, to support a sectoral trade initiative to expand investment and trade in energy-related goods and services that will enhance exploration, production, and refining, as well as the development of new technologies.
- ★ The NEPD Group recommends that the President direct the Secretaries of State, Treasury, and Commerce to initiate a comprehensive review of sanctions. Energy security should be one of the factors considered in such a review.
- ★ The NEPD Group recommends that the President direct the Secretaries of State, Commerce, and Energy to engage in a dialogue through the North American Energy Working Group to develop closer energy integration among Canada, Mexico, and the United States and identify areas of cooperation, fully consistent with the countries' respective sovereignties.
- ★ The NEPD Group recommends that the President direct the Secretaries of Energy and State, in consultation with the Federal Energy Regulatory Commission, to review their respective oil, natural gas, and electricity cross-boundary "Presidential Permitting" authorities, and to propose reforms as necessary in order to make their own regulatory regimes more compatible for cross-border trade.
- ★ The NEPD Group recommends that the President direct the Secretaries of Energy and State, coordinating with the Secretary of the Interior and the Federal Energy Regulatory Commission, to work closely with Canada, the State of Alaska, and all other interested parties to expedite the construction of a pipeline to deliver natural gas to the lower 48 states. This should include proposing to Congress any changes or waivers of law pursuant to the Alaska Natural Gas Transportation Act of 1976 that may be required.

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- ★ The NEPD Group recommends that the President direct the Secretaries of State and Commerce to conclude negotiations with Venezuela on a Bilateral Investment Treaty, and propose formal energy consultations with Brazil, to improve the energy investment climate for the growing level of energy investment flows between the United States and each of these countries.
 - ★ The NEPD Group recommends that the President direct the Secretaries of Energy, Commerce, and State to work through the Summit of the Americas Hemispheric Energy Initiative to develop effective and stable regulatory frameworks and foster reliable supply sources of all fuels within the region.
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 - ★ The NEPD Group recommends that the President direct the Secretaries of State, Commerce, and Energy to support more transparent, accountable, and responsible use of oil resources in African producer countries to enhance the stability and security of trade and investment environments.
 - ★ The NEPD Group recommends that the President direct the Secretaries of State, Commerce, and Energy to support the BTC oil pipeline as it demonstrates its commercial viability.
 - ★ The NEPD Group recommends that the President direct the Secretaries of Commerce, State, and Energy to continue working with relevant companies and countries to establish the commercial conditions that will allow oil companies operating in Kazakhstan the option of exporting their oil via the BTC pipeline.
 - ★ The NEPD Group recommends that the President direct the Secretaries of State, Commerce, and Energy to support the efforts of private investors and regional governments to develop the Shah Deniz gas pipeline as a way to help Turkey and Georgia diversify their natural gas supplies and help Azerbaijan export its gas via a pipeline that will continue diversification of secure energy supply routes.
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 - ★ The NEPD Group recommends that the President direct the Secretary of State to encourage Greece and Turkey to link their gas pipeline systems to allow European consumers to diversify their gas supplies by purchasing Caspian gas.

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- ★ The NEPD Group recommends that the President direct the Secretaries of Commerce, Energy, and State to deepen their commercial dialogue with Kazakhstan, Azerbaijan, and other Caspian states to provide a strong, transparent, and stable business climate for energy and related infrastructure projects.
 - ★ The NEPD Group recommends that the President direct the Secretaries of State, Commerce, and Energy to deepen the focus of the discussions with Russia on energy and the investment climate.
 - ★ The NEPD Group recommends that the President direct the Secretaries of Commerce, State, and Energy to assist U.S. companies in their dialogue on the investment and trade climate with Russian officials, to encourage reform of the PSA law and other regulations and related tax provisions, as well as general improvements in the overall investment climate. This will help expand private investment opportunities in Russia and will increase the international role of Russian firms.
 - ★ The NEPD Group recommends that the President direct the Secretaries of State, Commerce, and Energy to continue to work in the APEC Energy Working Group to examine oil market data transparency issues and the variety of ways petroleum stocks can be used as an option to address oil market disruptions.
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 - ★ The NEPD Group recommends that the President direct the Secretaries of Commerce, State, and Energy to promote market-based solutions to environmental concerns; support exports of U.S. clean energy technologies and encourage their overseas development; engage bilaterally and multilaterally to promote best practices; explore collaborative international basic research and development in energy alternatives and energy-efficient technologies; and explore innovative programs to support the global adoption of these technologies.
 - ★ The NEPD Group recommends that the President direct federal agencies to support continued research into global climate change; continue efforts to identify environmentally and cost-effective ways to use market mechanisms and incentives; continue development of new technologies; and cooperate with allies, including through international processes, to develop technologies, market-based incentives, and other innovative approaches to address the issue of global climate change.
 - ★ The NEPD Group recommends that the President seek to increase international cooperation on finding alternatives to oil, especially for the transportation sector.
 - ★ The NEPD Group recommends that the President direct the Secretary of State to reinvigorate its dialogue with the European Union on energy issues, and resume the consultative process this year in Washington.

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- ★ The NEPD Group recommends that the President promote a coordinated approach to energy security by calling for an annual meeting of G-8 Energy Ministers or their equivalents.
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 - ★ The NEPD Group recommend that the President direct the Secretary of Energy to work within the International Energy Agency (IEA) to ensure that member states fulfill their stockholding.
 - ★ The NEPD Group recommends that the President direct the Secretary of Energy to encourage major oil-consuming countries that are not IEA members to consider strategic stocks as an option for addressing potential supply disruptions. In this regard, we should work closely with Asian economies, especially through APEC.
 - ★ The NEPD Group recommends that the President direct the Secretary of Energy to offer to lease excess SPR storage facilities to countries (both IEA and non-IEA members) that might not otherwise build storage facilities or hold sufficient strategic stocks, consistent with statutory authorities.
 - ★ The NEPD Group recommends that the President, at such time that exchanged SPR barrels are returned to the SPR, should determine whether offshore Gulf of Mexico royalty oil deposits to the SPR should be resumed, thereby increasing the size of our reserve.
 - ★ The NEPD Group recommends that the President direct the Secretary of Energy to work closely with Congress to ensure that our SPR protection is maintained.
 - ★ The NEPD Group recommends that the President direct the Secretary of Energy to work with producer and consumer country allies and the IEA to craft a more comprehensive and timely world oil data reporting system.

CHAPTER ONE

Taking Stock: Energy Challenges Facing the United States

★ The NEPD Group recommends that the President issue an Executive Order to direct all federal agencies to include in any regulatory action that could significantly and adversely affect energy supplies, distribution, or use, a detailed statement on: (1) the energy impact of the proposed action, (2) any adverse energy effects that cannot be avoided should the proposal be implemented, and (3) alternatives to the proposed action. The agencies would be directed to include this statement in all submissions to the Office of Management and Budget of proposed regulations covered by Executive Order 12866, as well as in all notices of proposed regulations published in the Federal Register.

★ The NEPD Group recommends that the President direct the executive agencies to work closely with Congress to implement the legislative components of a national energy policy.

★ The NEPD Group recommends to the President that the NEPD Group continue to work and meet on the implementation of the National Energy Policy and explore other ways to advance dependable, affordable, and environmentally responsible production and distribution of energy.

Note: All recommendations in this report are subject to execution in accordance with applicable law. Legislation would be sought where needed. Also, any recommendations that involve foreign countries would be executed in accordance with the customs of international relations, including appropriate diplomatic consultation.

CHAPTER TWO

Striking Home

The Impacts of

High Energy

Prices on

Families,

Communities,

and Businesses

★ The NEPD Group recommends that the President direct the Secretary of Energy to explore potential opportunities to develop educational programs related to energy development and use. This should include possible legislation to create public education awareness programs about energy. Such programs should be long-term in nature, should be funded and managed by the respective energy industries, and should include information on energy's compatibility with a clean environment.

★ The NEPD Group recommends that the President take steps to mitigate impacts of high energy costs on low-income consumers. These steps would include:

- Strengthening the Low Income Home Energy Assistance Program by making \$1.7 billion available annually. This is an increase of \$300 million over the regular FY 2001 appropriation.
- Directing the Secretaries of Interior and Health and Human Services to propose legislation to bolster LIHEAP funding by using a portion of oil and gas royalty payments.
- Redirecting royalties above a set trigger price to LIHEAP, whenever crude oil and natural gas prices exceed that trigger price, as determined by the responsible agencies.

★ The NEPD Group recommends that the President increase funding for the Weatherization Assistance Program by \$1.2 billion over ten years. This will roughly double the spending during that period on weatherization. Consistent with that commitment, the FY 2002 Budget includes a \$120 million increase over 2001. The Department of Energy will have the option of using a portion of those funds to test improved implementation approaches for the weatherization program.

★ The NEPD Group recommends that the President support legislation to allow funds dedicated for the Weatherization and State Energy Programs to be transferred to LIHEAP if the Department of Energy deems it appropriate.

★ The NEPD Group recommends the President recognize unique regional energy concerns by working with the National Governors Association and regional governor associations to determine how to better serve the needs of diverse areas of the country.

★ The NEPD Group recommends the President direct FEMA to prepare for potential energy emergencies.

- FEMA should work with states' Offices of Emergency Management as they expand existing emergency operations plans to identify potential problems and address consequences of the power shortages. FEMA should use its current Regional Incident Reporting System to identify any situations that might demand immediate attention.
- Using the structure of the already existing Federal Response Plan, FEMA should conduct Regional Interagency Steering Committee (RISC) meetings for states affected by the energy shortfalls. The RISC is a FEMA-led interagency committee comprised of agencies and departments that support the Federal Response Plan. Either an upcoming, scheduled RISC meeting or a special-focus RISC meeting can be held to identify the short-term energy outlook, as well as any expected consequences, in each of the states during the peak summer season.

CHAPTER THREE

Protecting America's Environment: Sustaining the Nation's Health and Environment

- ★ The NEPD Group recommends that the President direct the Administrator of the Environmental Protection Agency (EPA) to propose multi-pollutant legislation. The NEPD Group recommends that the President direct the EPA Administrator to work with Congress to propose legislation that would establish a flexible, market-based program to significantly reduce and cap emissions of sulfur dioxide, nitrogen oxides, and mercury from electric power generators. Such a program (with appropriate measures to address local concerns) would provide significant public health benefits even as we increase electricity supplies.
 - Establish mandatory reduction targets for emissions of three main pollutants: sulfur dioxide, nitrogen oxides, and mercury.
 - Phase in reductions over a reasonable period of time, similar to the successful acid rain reduction program established by the 1990 amendments to the Clean Air Act.
 - Provide regulatory certainty to allow utilities to make modifications to their plants without fear of new litigation.
 - Provide market-based incentives, such as emissions trading credits to help achieve the required reductions.

- ★ The NEPD Group recommends the President direct the Secretary of the Interior to work with Congress to create the “Royalties Conservation Fund.”
 - This fund will earmark potentially billions of dollars in royalties from new oil and gas production in ANWR to fund land conservation efforts.
 - This fund will also be used to eliminate the maintenance and improvements backlog on federal lands.

- ★ The NEPD Group recommends the President issue an Executive Order to rationalize permitting for energy production in an environmentally sound manner by directing federal agencies to expedite permits and other federal actions necessary for energy related project approvals on a national basis. This order would establish an inter agency task force chaired by the Council on Environmental Quality to ensure that federal agencies responsible for permitting energy-related facilities are coordinating their efforts. The task force will ensure that federal agencies set up appropriate mechanisms to coordinate federal, state, tribal, and local permitting activity in particular regions where increased activity is expected.

CHAPTER FOUR

Using Energy Wisely: Increasing Energy Conservation and Efficiency

- ★ The NEPD Group recommends that the President direct the Office of Science and Technology Policy and the President's Council of Advisors on Science and Technology to review and make recommendations on using the nation's energy resources more efficiently.
- ★ The NEPD Group recommends that the President direct the Secretary of Energy to conduct a review of current funding and historic performance of energy efficiency research and development programs in light of the recommendations of this report. Based on this review, the Secretary of Energy is then directed to propose appropriate funding of those research and development programs that are performance-based and are modeled as public-private partnerships.
- ★ The NEPD Group recommends that the President direct the Secretary of Energy to promote greater energy efficiency.
 - Expand the Energy Star program beyond office buildings to include schools, retail buildings, health care facilities, and homes.
 - Extend the Energy Star labeling program to additional products, appliances, and services.
 - Strengthen Department of Energy public education programs relating to energy efficiency.
- ★ The NEPD Group recommends that the President direct the Secretary of Energy to improve the energy efficiency of appliances.
 - Support the appliance standards program for covered products, setting higher standards where technologically feasible and economically justified.
 - Expand the scope of the appliance standards program, setting standards for additional appliances where technologically feasible and economically justified.
- ★ The NEPD Group recommends that the President direct heads of executive departments and agencies to take appropriate actions to conserve energy use at their facilities to the maximum extent consistent with the effective discharge of public responsibilities. Agencies located in regions where electricity shortages are possible should conserve especially during periods of peak demand. Agencies should report to the President, through the Secretary of Energy, within 30 days on the conservation actions taken.
- ★ The NEPD Group recommends that the President direct the Secretary of the Treasury to work with Congress to encourage increased energy efficiency through combined heat and power (CHP) projects by shortening the depreciation life for CHP projects or providing investment tax credits.
- ★ The NEPD Group recommends that the President direct the Administrator of the Environmental Protection Agency (EPA) to work with local and state governments to promote the use of well-designed CHP and other clean power generation at brownfields sites, consistent with the local communities' interests. EPA will also work to clarify liability issues if they are raised at a particular site.

CHAPTER FOUR

- ★ The NEPD Group recommends that the President direct the EPA Administrator to promote CHP through flexibility in environmental permitting.

- ★ The NEPD Group recommends that the President direct the Secretary of Transportation to:
 - Review and provide recommendations on establishing Corporate Average Fuel Economy (CAFE) standards with due consideration of the National Academy of Sciences study to be released in July 2001. Responsibly crafted CAFE standards should increase efficiency without negatively impacting the U.S. automotive industry. The determination of future fuel economy standards must therefore be addressed analytically and based on sound science.
 - Consider passenger safety, economic concerns, and disparate impact on the U.S. versus foreign fleet of automobiles.
 - Look at other market-based approaches to increasing the national average fuel economy of new motor vehicles.

- ★ The new NEPD Group recommends that the President direct the Secretary of Transportation to review and promote congestion mitigation technologies and strategies and work with Congress on legislation to implement these strategies.

- ★ The NEPD Group recommends that the President direct the Secretary of the Treasury to work with Congress on legislation to increase energy efficiency with a tax credit for fuel-efficient vehicles. The NEPD Group recommends that a temporary, efficiency based income tax credit be available for purchase of new hybrid fuel cell vehicles between 2002 and 2007.

- ★ The NEPD Group recommends that the President direct all agencies to use technological advances to better protect our environment.
 - The Administration remains committed to investing in Intelligent Transportation Systems (ITS) and encourages the private sector to invest in ITS applications. This Department of Transportation (DOT) program funds the development of improved transportation infrastructure that will reduce congestion, such as traveler information/navigation systems, freeway management, and electronic toll collection. ITS applications reduce fuel associated with travel.
 - The Administration remains committed to the DOT's fuel-cell-powered transit bus program, authored by the Transportation Equity Act for the 21st Century (TEA-21). This program demonstrates the viability of fuel-cell power plants for transit bus applications.
 - The Administration remains committed to the Clean Buses program. TEA-21 establishes a new clean fuel formula grant program, which provides an opportunity to accelerate the introduction of advanced bus propulsion technologies into the mainstream of the nation's transit fleet.

- ★ The NEPD Group recommends that the President direct the EPA and DOT to develop ways to reduce demand for petroleum transportation fuels by working with the trucking industry to establish a program to reduce emissions and fuel consumption from long-haul trucks at truck stops by implementing alternatives to idling, such as electrification and auxiliary power units at truck stops along interstate highways. EPA and DOT will develop partnership agreements with trucking fleets, truck stops, and manufacturers of idle-reducing technologies (*e.g.*, portable auxiliary packs, electrification) to install and use low emission-idling technologies.

- ★ The NEPD Group recommends that the President direct the Secretary of Energy to establish a national priority for improving energy efficiency. The priority would be to improve the energy intensity of the U.S. economy as measured by the amount of energy required for each dollar of economic productivity. This increased efficiency should be pursued through the combined efforts of industry, consumers, and federal, state, and local governments.

- ★ The NEPD Group recommends that the President direct the EPA Administrator to develop and implement a strategy to increase public awareness of the sizable savings that energy efficiency offers to homeowners across the country. Typical homeowners can save about 30 percent (about \$400) a year on their home energy bill by using Energy Star labeled products.

Chapter Five Energy for a New Century: Increasing Domestic Energy Supplies

- ★ The NEPD Group recommends that the President direct the Secretaries of Energy and the Interior to promote enhanced oil and gas recovery from existing wells through new technology.
- ★ The NEPD Group recommends that the President direct the Secretary of Energy to improve oil and gas exploration technology through continued partnership with public and private entities.
- ★ The NEPD Group recommends that the President direct the Secretary of the Interior to examine land status and lease stipulation impediments to federal oil and gas leasing, and review and modify those where opportunities exist (consistent with the law, good environmental practice, and balanced use of other resources).
 - Expedite the ongoing Energy Policy and Conservation Act study of impediments to federal oil and gas exploration and development.
 - Review public lands withdrawals and lease stipulations, with full public consultation, especially with the people in the region, to consider modifications where appropriate.
- ★ The NEPD Group recommends that the President direct the Secretary of the Interior to consider economic incentives for environmentally sound offshore oil and gas development where warranted by specific circumstances: explore opportunities for royalty reductions, consistent with ensuring a fair return to the public where warranted for enhanced oil and gas recovery; for reduction of risk associated with production in frontier areas or deep gas formations; and for development of small fields that would otherwise be uneconomic.
- ★ The NEPD Group recommends that the President direct the Secretaries of Commerce and Interior to re-examine the current federal legal and policy regime (statutes, regulations, and Executive Orders) to determine if changes are needed regarding energy-related activities and the siting of energy facilities in the coastal zone and on the Outer Continental Shelf (OCS).
- ★ The NEPD Group recommends that the President direct the Secretary of the Interior to continue OCS oil and gas leasing and approval of exploration and development plans on predictable schedules.
- ★ The NEPD Group recommends that the President direct the Secretary of the Interior to consider additional environmentally responsible oil and gas development, based on sound science and the best available technology, through further lease sales in the National Petroleum Reserve-Alaska. Such consideration should include areas not currently leased within the Northeast corner of the Reserve.
- ★ The NEPD Group recommends that the President direct the Secretary of the Interior to work with Congress to authorize exploration and, if resources are discovered, development of the 1002 Area of ANWR. Congress should require the use of the best available technology and should require that activities will result in no significant adverse impact to the surrounding environment.
- ★ The NEPD Group recommends that the President direct the Secretary of the Interior to work with Congress and the State of Alaska to put in place the most expeditious process for renewal of the Trans-Alaska Pipeline System rights-of-way to ensure that Alaskan oil continues to flow uninterrupted to the West Coast of the United States.

★ The NEPD Group recommends that the President direct the Secretary of Energy to propose comprehensive electricity legislation that promotes competition, protects consumers, enhances reliability, promotes renewable energy, improves efficiency repeals the Public Utility Holding Company Act, and reforms the Public Utility Regulatory Policies Act.

★ The NEPD Group recommends that the President encourage FERC to use its existing statutory authority to promote competition and encourage investment in transmission facilities.

★ The NEPD Group recognizes the importance of looking to technology to help us meet the goals of increasing electricity generation while protecting our environment. To that end, the NEPD Group recommends that the President direct the Department of Energy to continue to develop advanced clean coal technology by:

- Investing \$2 billion over 10 years to fund research in clean coal technologies.
- Supporting a permanent extension of the existing research and development tax credit.
- Directing federal agencies to explore regulatory approaches that will encourage advancements in environmental technology.

★ The NEPD Group recommends that the President direct federal agencies to provide greater regulatory certainty relating to coal electricity generation through clear policies that are easily applied to business decisions.

★ The NEPD Group recommends that the President support the expansion of nuclear energy in the United States as a major component of our national energy policy. Following are specific components of the recommendation:

- Encourage the Nuclear Regulatory Commission (NRC) to ensure that safety and environmental protection are high priorities as they prepare to evaluate and expedite applications for licensing new advanced-technology nuclear reactors.
- Encourage the NRC to facilitate efforts by utilities to expand nuclear energy generation in the United States by uprating existing nuclear plants safely.
- Encourage the NRC to relicense existing nuclear plants that meet or exceed safety standards.
- Direct the Secretary of Energy and the Administrator of the Environmental Protection Agency to assess the potential of nuclear energy to improve air quality.
- Increase resources as necessary for nuclear safety enforcement in light of the potential increase in generation.
- Use the best science to provide a deep geologic repository for nuclear waste.
- Support legislation clarifying that qualified funds set aside by plant owners for eventual decommissioning will not be taxed as part of the transaction.
- Support legislation to extend the Price–Anderson Act.

★ The NEPD Group recommends that, in the context of developing advanced nuclear fuel cycles and next generation technologies for nuclear energy, the United States should reexamine its policies to allow for research, development and deployment of fuel conditioning methods (such as pyroprocessing) that reduce waste streams and enhance proliferation resistance. In doing so, the United States will continue to discourage the accumulation of separated plutonium, worldwide.

★ The United States should also consider technologies (in collaboration with international partners with highly developed fuel cycles and a record of close cooperation) to develop reprocessing and fuel treatment technologies that are cleaner, more efficient, less waste intensive, and more proliferation-resistant.

CHAPTER FIVE

★ The NEPD Group recognizes there is a need to reduce the time and cost of the hydro power licensing process. The NEPD Group recommends that the President encourage the Federal Energy Regulatory Commission (FERC) and direct federal resource agencies to make the licensing process more clear and efficient, while preserving environmental goals. In addition, the NEPD Group recognizes the importance of optimizing the efficiency and reliability of existing hydropower facilities and will encourage the Administration to adopt efforts to ward that end.

- Support administrative and legislative reform of the hydropower licensing process.
- Direct federal resource agencies to reach interagency agreement on conflicting mandatory license conditions before they submit their conditions to FERC for inclusion in a license.
- Encourage FERC to adopt appropriate deadlines for its own actions during the licensing process.

CHAPTER SIX

Nature's Power: Increasing America's Use of Renewable and Alternative Energy

- ★ The NEPD Group recommends that the President direct the Secretaries of the Interior and Energy to re-evaluate access limitations to federal lands in order to increase renewable energy production, such as biomass, wind, geothermal, and solar.
- ★ The NEPD Group supports the increase of \$39.2 million in the FY 2002 budget amendment for the Department of Energy's Energy Supply account that would provide increased support for research and development of renewable energy resources.
- ★ The NEPD Group recommends that the President direct the Secretary of Energy to conduct a review of current funding and historic performance of renewable energy and alternative energy research and development programs in light of the recommendations of this report. Based on this review, the Secretary of Energy is then directed to propose appropriate funding of those research and development programs that are performance-based and are modeled as public-private partnerships.
- ★ The NEPD Group recommends that the President direct the Secretary of the Treasury to work with Congress on legislation to expand the section 29 tax credit to make it available for new landfill methane projects. The credit could be tiered, depending on whether a landfill is already required by federal law to collect and flare its methane emissions due to local air pollution concerns.
- ★ The NEPD Group recommends that the President direct the Secretary of the Interior to determine ways to reduce the delays in geothermal lease processing as part of the permitting review process.
- ★ The NEPD Group recommends that the President direct the Administrator of the Environmental Protection Agency to develop a new renewable energy partnership program to help companies more easily buy renewable energy, as well as receive recognition for the environmental benefits of their purchase, and help consumers by promoting consumer choice programs that increase their knowledge about the environmental benefits of purchasing renewable energy.
- ★ The NEPD Group recommends that the President direct the Secretary of the Treasury to work with Congress on legislation to extend and expand tax credits for electricity produced using wind and biomass. The President's budget request extends the present 1.7 cents per kilowatt hour tax credit for electricity produced from wind and biomass; expands eligible biomass sources to include forest-related sources, agricultural sources, and certain urban sources; and allows a credit for electricity produced from biomass co-fired with coal.
- ★ The NEPD Group recommends that the President direct the Secretary of the Treasury to work with Congress on legislation to provide a new 15 percent tax credit for residential solar energy property, up to a maximum credit of \$2,000.
- ★ The NEPD Group recommends that the President direct the Secretaries of the Interior and Energy to work with Congress on legislation to use an estimated \$1.2 billion of bid bonuses from the environmentally responsible leasing of ANWR for funding research into alternative and renewable energy resources, including wind, solar, geothermal, and biomass.
- ★ The NEPD Group recommends that the President direct the Secretary of the Treasury to work with Congress to continue the ethanol excise tax exemption.

CHAPTER SIX

- ★ The NEPD Group recommends that the President direct the Secretary of Energy to develop next-generation technology—including hydrogen and fusion.
 - Develop an education campaign that communicates the benefits of alternative forms of energy, including hydrogen and fusion.
 - Focus research and development efforts on integrating current programs regarding hydrogen, fuel cells, and distributed energy.
 - Support legislation reauthorizing the Hydrogen Energy Act.
- ★ The NEPD Group recommends that the President direct the Secretary of the Treasury to work with Congress to develop legislation to provide for a temporary income tax credit available for the purchase of new hybrid or fuel-cell vehicles between 2002 and 2007.
- ★ The NEPD Group recommends that the President direct the Administrator of the Environmental Protection Agency to issue guidance to encourage the development of well-designed combined heat and power (CHP) units that are both highly efficient and have low emissions. The goal of this guidance would be to shorten the time needed to obtain each permit, provide certainty to industry by ensuring consistent implementation across the country, and encourage the use of these cleaner, more efficient technologies.

CHAPTER SEVEN

America's Energy Infrastructure: A Comprehensive Delivery System

- ★ The NEPD Group recommends that the President direct the Secretary of Energy to work with the Federal Energy Regulatory Commission (FERC) to improve the reliability of the interstate transmission system and to develop legislation providing for enforcement by a self-regulatory organization subject to FERC oversight.
- ★ The NEPD Group recommends that the President direct the Secretary of Energy to expand the Department's research and development on transmission reliability and superconductivity.
- ★ The NEPD Group recommends that the President direct the Secretary of Energy to authorize the Western Area Power Administration to explore relieving the "Path 15" bottle neck through transmission expansion financed by nonfederal contributions.
- ★ The NEPD Group recommends that the President direct the appropriate federal agencies to take actions to remove constraints on the interstate transmission grid and allow our nation's electricity supply to meet the growing needs of our economy.
 - Direct the Secretary of Energy, by December 31, 2001, to examine the benefits of establishing a national grid, identify transmission bottlenecks, and identify measures to remove transmission bottlenecks.
 - Direct the Secretary of Energy to work with FERC to relieve transmission constraints by encouraging the use of incentive rate-making proposals.
 - Direct the federal utilities to determine whether transmission expansions are necessary to remove constraints. The Administration should review the Bonneville Power Administration's (BPA's) capital and financing requirements in the context of its membership in a regional RTO, and if additional Treasury financing appears warranted or necessary in the future, the Administration should seek an increase in BPA's borrowing authority at that time.
 - Direct the Secretary of Energy, in consultation with appropriate federal agencies and state and local government officials, to develop legislation to grant authority to obtain rights-of-way for electricity transmission lines, with the goal of creating a reliable national transmission grid. Similar authority already exists for natural gas pipelines in recognition of their role in interstate commerce.
- ★ The NEPD Group recommends that the President direct the Secretary of the Interior to work with Congress and the State of Alaska to put in place the most expeditious process for renewal of the Trans-Alaskan Pipeline System lease to ensure that Alaskan oil continues to flow uninterrupted to the West Coast of the United States.
- ★ The NEPD Group recommends that the President direct the Secretaries of Energy and State, coordinating with the Secretary of the Interior and the Federal Energy Regulatory Commission, to work closely with Canada, the State of Alaska, and all other interested parties to expedite the construction of a pipeline to deliver natural gas to the lower 48 states. This should include proposing to Congress any changes or waivers of law pursuant to the Alaska Natural Gas Transportation Act of 1976 that may be required.
- ★ The NEPD Group recommends that the President support legislation to improve the safety of natural gas pipelines, protect the environment, strengthen emergency preparedness and inspections and bolster enforcement.

CHAPTER SEVEN

- ★ The NEPD Group recommends that the President direct agencies to continue their interagency efforts to improve pipeline safety and expedite pipeline permitting in an environmentally sound manner and encourage FERC to consider improvements in the regulatory process governing approval of interstate natural gas pipeline projects.
- ★ The NEPD Group recommends that the President direct the Administrator of the EPA to study opportunities to maintain or improve the environmental benefits of state and local “boutique” clean fuel programs while exploring ways to increase the flexibility of the fuels distribution infrastructure, improve fungibility, and provide added gasoline market liquidity. In concluding this study, the Administrator shall consult with the Departments of Energy and Agriculture, and other agencies as needed.
- ★ The NEPD Group recommends that the President direct the Administrator of the Environmental Protection Agency and the Secretary of Energy to take steps to ensure America has adequate refining capacity to meet the needs of consumers.
 - Provide more regulatory certainty to refinery owners and streamline the permitting process where possible to ensure that regulatory overlap is limited.
 - Adopt comprehensive regulations (covering more than one pollutant and require ment) and consider the rules’ cumulative impacts and benefits.
- ★ The NEPD Group recommends that the President direct the Administrator of the Environmental Protection Agency, in consultation with the Secretary of Energy and other relevant agencies, to review New Source Review regulations, including administrative interpretation and implementation, and report to the President within 90 days on the impact of the regulations on investment in new utility and refinery generation capacity, energy efficiency, and environmental protection.
- ★ The NEPD Group recommends that the President direct the Attorney General to review existing enforcement actions regarding New Source Review to ensure that the enforcement actions are consistent with the Clean Air Act and its regulations.
- ★ The NEPD Group supports the President’s budget proposal to provide \$8 million to maintain the two-million-barrel Northeast Heating Oil Reserve. Operated by the private sector, the Reserve helps ensure adequate supplies of heating oil in the event that colder than normal winters occur in the Northeast United States.

CHAPTER 8

Strengthening Global Alliances: Enhancing National Energy Security and International Relationships

- ★ The NEPD Group recommends that the President make energy security a priority of our trade and foreign policy.
- ★ The NEPD Group recommends the President support initiatives by Saudi Arabia, Kuwait, Algeria, Qatar, the UAE, and other suppliers to open up areas of their energy sectors to foreign investment.
- ★ The NEPD Group recommends that the President direct the Secretaries of State, Energy and Commerce work to improve dialogue among energy producing and consuming nations.
- ★ The NEPD Group recommends that the President direct the Secretaries of State, Commerce, and Energy to continue supporting American energy firms competing in markets abroad and use our membership in multilateral organizations, such as the Asia-Pacific Economic Cooperation (APEC) forum, the Organization for Economic Cooperation and Development (OECD), the World Trade Organization (WTO) Energy Services Negotiations, the Free Trade Area of the Americas (FTAA), and our bilateral relationships to implement a system of clear, open, and transparent rules and procedures governing foreign investment; to level the playing field for U.S. companies overseas; and to reduce barriers to trade and investment.
- ★ The NEPD Group recommends that the President direct the Secretaries of Commerce and Energy, and the U.S. Trade Representative, to support a sectoral trade initiative to expand investment and trade in energy-related goods and services that will enhance exploration, production, and refining, as well as the development of new technologies.
- ★ The NEPD Group recommends that the President direct the Secretaries of State, Treasury, and Commerce to initiate a comprehensive review of sanctions. Energy security should be one of the factors considered in such a review.
- ★ The NEPD Group recommends that the President direct the Secretaries of State, Commerce, and Energy to engage in a dialogue through the North American Energy Working Group to develop closer energy integration among Canada, Mexico, and the United States and identify areas of cooperation, fully consistent with the countries' respective sovereignties.
- ★ The NEPD Group recommends that the President direct the Secretaries of Energy and State, in consultation with the Federal Energy Regulatory Commission, to review their respective oil, natural gas, and electricity cross-boundary "Presidential Permitting" authorities, and to propose reforms as necessary in order to make their own regulatory regimes more compatible for cross-border trade.
- ★ The NEPD Group recommends that the President direct the Secretaries of Energy and State, coordinating with the Secretary of the Interior and the Federal Energy Regulatory Commission, to work closely with Canada, the State of Alaska, and all other interested parties to expedite the construction of a pipeline to deliver natural gas to the lower 48 states. This should include proposing to Congress any changes or waivers of law pursuant to the Alaska Natural Gas Transportation Act of 1976 that

CHAPTER EIGHT

may be required.

★ The NEPD Group recommends that the President direct the Secretaries of State and Commerce to conclude negotiations with Venezuela on a Bilateral Investment Treaty, and propose formal energy consultations with Brazil, to improve the energy investment climate for the growing level of energy investment flows between the United States and each of these countries.

★ The NEPD Group recommends that the President direct the Secretaries of Energy, Commerce, and State to work through the Summit of the Americas Hemispheric Energy Initiative to develop effective and stable regulatory frameworks and foster reliable supply sources of all fuels within the region.

★ The NEPD Group recommends that the President direct the Secretaries of State, Energy, and Commerce to reinvigorate the U.S.-Africa Trade and Economic Cooperation Forum and the U.S.-African Energy Ministerial process; deepen bilateral and multilateral engagement to promote a more receptive environment for U.S. oil and gas trade, investment, and operations; and promote geographic diversification of energy supplies, addressing such issues as transparency, sanctity of contracts, and security.

★ The NEPD Group recommends that the President direct the Secretaries of State, Commerce, and Energy to support more transparent, accountable, and responsible use of oil resources in African producer countries to enhance the stability and security of trade and investment environments.

★ The NEPD Group recommends that the President direct the Secretaries of State, Commerce, and Energy to support the BTC oil pipeline as it demonstrates its commercial viability.

★ The NEPD Group recommends that the President direct the Secretaries of Commerce, State, and Energy to continue working with relevant companies and countries to establish the commercial conditions that will allow oil companies operating in Kazakhstan the option of exporting their oil via the BTC pipeline.

★ The NEPD Group recommends that the President direct the Secretaries of State, Commerce, and Energy to support the efforts of private investors and regional governments to develop the Shah Deniz gas pipeline as a way to help Turkey and Georgia diversify their natural gas supplies and help Azerbaijan export its gas via a pipeline that will continue diversification of secure energy supply routes.

★ The NEPD Group recommends that the President direct appropriate federal agencies to complete the current cycle of oil spill response readiness workshops and to consider further appropriate steps to ensure the implementation of the workshops' recommendations.

★ The NEPD Group recommends that the President direct the Secretary of State to encourage Greece and Turkey to link their gas pipeline systems to allow European consumers to diversify their gas supplies by purchasing Caspian gas.

★ The NEPD Group recommends that the President direct the Secretaries of Commerce, Energy, and State to deepen their commercial dialogue with Kazakhstan, Azerbaijan, and other Caspian states to provide a strong, transparent, and stable-business climate for energy and related infrastructure projects.-

★ The NEPD Group recommends that the President direct the Secretaries of State, Commerce, and Energy to deepen the focus of the discussions with Russia on energy and the investment climate.-

★ The NEPD Group recommends that the President direct the Secretaries of Commerce, State, and Energy to assist U.S. companies in their dialogue on the investment and trade climate with Russian officials, to encourage reform of the PSA law and other regulations and related tax provisions, as well as general improvements in the overall investment climate. This will help expand private investment opportunities in Russia and will increase the international role of Russian firms.-

★ The NEPD Group recommends that the President direct the Secretaries of State, Commerce, and Energy to continue to work in the APEC Energy Working Group to examine oil market data transparency issues and the variety of ways petroleum stocks can be used as an option to address oil market disruptions.-

★ The NEPD Group recommends that the President direct the Secretaries of State and Energy to work with India's Ministry of Petroleum and Natural Gas to help India maximize its domestic oil and gas production.-

★ The NEPD Group recommends that the President direct the Secretaries of Commerce, State, and Energy to promote market-based solutions to environmental concerns; support exports of U.S. clean energy technologies and encourage their overseas development; engage bilaterally and multilaterally to promote best practices; explore collaborative international basic research and development in energy alternatives and energy-efficient technologies; and explore innovative programs to support the global adoption of these technologies.-

★ The NEPD Group recommends that the President direct federal agencies to support continued research into global climate change; continue efforts to identify environmentally and cost-effective ways to use market mechanisms and incentives; continue development of new technologies; and cooperate with allies, including through international processes, to develop technologies, market-based incentives, and other innovative approaches to address the issue of global climate change.-

★ The NEPD Group recommends that the President seek to increase international cooperation on finding alternatives to oil, especially for the transportation sector.-

★ The NEPD Group recommends that the President direct the Secretary of State to reinvigorate its dialogue with the European Union on energy issues, and resume the consultative process this year in Washington.-

★ The NEPD Group recommends that the President promote a coordinated approach to energy security by calling for an annual meeting of G-8 Energy Ministers or their equivalents.-

CHAPTER EIGHT

- ★ The NEPD Group recommends that the President reaffirm that the SPR is designed for addressing an imminent or actual disruption in oil supplies, and not for managing prices.
- ★ The NEPD Group recommend that the President direct the Secretary of Energy to work within the International Energy Agency (IEA) to ensure that member states fulfill their stockholding.
- ★ The NEPD Group recommends that the President direct the Secretary of Energy to encourage major oil-consuming countries that are not IEA members to consider strategic stocks as an option for addressing potential supply disruptions. In this regard, we should work closely with Asian economies, especially through APEC.
- ★ The NEPD Group recommends that the President direct the Secretary of Energy offer to lease excess SPR storage facilities to countries (both IEA and non-IEA members) that might not otherwise build storage facilities or hold sufficient strategic stocks, consistent with statutory authorities.
- ★ The NEPD Group recommends that the President, at such time that exchanged SPR barrels are returned to the SPR, should determine whether offshore Gulf of Mexico royalty oil deposits to the SPR should be resumed, thereby increasing the size of our reserve.
- ★ The NEPD Group recommends that the President direct the Secretary of Energy to work closely with Congress to ensure that our SPR protection is maintained.
- ★ The NEPD Group recommends that the President direct the Secretary of Energy to work with producer and consumer country allies and the IEA to craft a more comprehensive and timely world oil data reporting system.

Glossary

Barrel (Oil): A unit of volume equal to 42 U.S. gallons.

Barrels per Day (Operable Refinery Capacity): The maximum number of barrels of input that can be processed during a 24-hour period after making allowances for the following limitations: the capability of downstream facilities to absorb the output of crude oil processing facilities of a given refinery (no reduction is made when a planned distribution of intermediate streams through other than downstream facilities is part of a refinery's normal operation); the types and grades of inputs to be processed; the types and grades of products to be manufactured; the environmental constraints associated with refinery operations; the reduction of capacity for scheduled downtime, such as routine inspection, mechanical problems, maintenance, repairs, and turnaround; and the reduction of capacity for unscheduled downtime, such as mechanical problems, repairs, and slowdowns.

Biomass: Organic nonfossil material of biological origin constituting a renewable energy source.

British Thermal Unit (Btu): The quantity of heat needed to raise the temperature of 1 pound of water by 1°F at or near 39.2°F.

Coal: A readily combustible black or brownish-black rock whose composition, including inherent moisture, consists of more than 50 percent by weight and more than 70 percent by volume of carbonaceous material. It is formed from plant remains that have been compacted, hardened, chemically altered, and metamorphosed by heat and pressure over geologic time.

Cogeneration: The production of electricity and another form of useful energy (such as heat or steam) used for industrial, commercial, heating, or cooling purposes.

Commercial Building: A building with more than 50 percent of its floor space used for commercial activities. Commercial buildings include stores, offices, schools, churches, gymnasiums, libraries, museums, hospitals, clinics, warehouses, and jails. Government buildings are also included, except buildings on military bases or reservations.

Commercial Sector: Business establishments that are not engaged in transportation or in manufacturing or other types of industrial activity (agriculture, mining, or construction). Commercial establishments include hotels, motels, restaurants, wholesale businesses, retail stores, laundries, and other service enterprises; religious and nonprofit organizations; health, social, and educational institutions; and federal, state, and local governments. Streetlights, pumps, bridges, and public services are also included if the establishment operating them is considered commercial.

Conversion Factor: A number that translates units of one system into corresponding values of another system. Conversion factors can be used to translate physical units of measure for various fuels into Btu equivalents.

Crude Oil: A mixture of hydrocarbons that exists in liquid phase in natural underground reservoirs and remains liquid at atmospheric pressure after passing through surface separating facilities. Crude oil may also include:

- Small amounts of hydrocarbons that exist in the gaseous phase in natural underground reservoirs but are liquid at atmospheric pressure after being recovered from oil well (casing head) gas in lease separators and that subsequently are commingled with the crude stream without being separately measured.
- Small amounts of nonhydrocarbons produced with the oil, such as sulfur and other compounds

Crude Oil Stocks: Stocks of crude oil and lease condensate held at refineries, in pipelines, at pipeline terminals, and on leases.

District Heat: Steam or hot water from an outside source used as an energy source in a building. The steam or hot water is produced in a central plant and is piped into the building. District heat may be purchased from a utility or provided by a physical plant in a separate building that is part of the same facility (for example, a hospital complex or university).

Electric Power Plant: A station containing prime movers, electric generators, and auxiliary equipment for converting mechanical, chemical, and/or fission energy into electric energy.

Electricity Generation: The process of producing electric energy or transforming other forms of energy into electric energy. Also, the amount of electric energy produced or expressed in watt-hours (Wh).

End-Use Sectors: The residential, commercial, industrial, and transportation sectors of the economy.

Energy: The capacity for doing work as measured by the capability of doing work (potential energy), or the conversion of this capability to motion (kinetic energy). Energy has several forms, some of which are easily convertible and can be changed to another form useful for work. Most of the world's convertible energy comes from fossil fuels that are burned to produce heat that is then used as a transfer medium to mechanical or other means in order to accomplish tasks. Electrical energy is usually measured in kilowatt-hours, while heat energy is usually measured in British thermal units.

Energy Consumption: The use of energy as a source of heat or power or as an input in the manufacturing process.

Energy Source: A substance, such as oil, natural gas, or coal, that supplies heat or power. Electricity and renewable forms of energy, such as wood, waste, geothermal, wind, and solar, are considered to be energy sources.

Exports: Shipments of goods from the 50 states and the District of Columbia to foreign countries and to Puerto Rico, the Virgin Islands, and other U.S. possessions and territories.

Federal Energy Regulatory Commission (FERC): The federal agency with jurisdiction over interstate electricity sales, wholesale electric rates, hydroelectric licensing, natural gas pricing, oil pipeline rates, and gas pipeline certification. FERC is an independent regulatory agency within the Department of Energy and is the successor to the Federal Power Commission.

Fossil Fuel: Any naturally occurring organic fuel formed in the Earth's crust, such as oil, coal, and natural gas.

Fuel Ethanol: An anhydrous, denatured aliphatic alcohol intended for motor gasoline blending.

Gas-Turbine Electric Power Plant: A plant in which the prime mover is a gas turbine. A gas turbine typically consists of an axial-flow air compressor and one or more combustion chambers where liquid or gaseous fuel is burned. The hot gases expand to drive the generator and then are used to run the compressor.

Geothermal Energy: Energy from the internal heat of the Earth, which may be residual heat, friction heat, or a result of radioactive decay. The heat is found in rocks and fluids at various depths and can be extracted by drilling or pumping.

Gross Domestic Product (GDP): The total value of goods and services produced by labor and property located in the United States.

Hydrocarbon: An organic chemical compound of hydrogen and carbon in the gaseous, liquid, or solid phase. The molecular structure of hydrocarbon compounds varies from the simplest (methane, a constituent of natural gas) to the very heavy and very complex.

Hydropower: The production of electricity from the kinetic energy of falling water.

Hydropower Plant: A plant in which the turbine generators are driven by falling water.

Independent Power Producer: Wholesale electricity producers (other than qualifying facilities under the Public Utilities Regulatory Policies Act of 1978) that are unaffiliated with franchised utilities in the area in which the independent power producers are selling power and that lack significant marketing power. Unlike traditional electric utilities, independent power producers do not possess transmission facilities that are essential to their customers and do not sell power in any retail service territory where they have a franchise.

Industrial Sector: Manufacturing industries, which make up the largest part of the sector, along with mining, construction, agriculture, fisheries, and forestry. Establishments in this sector range from steel mills, to small farms, to companies assembling electronic components.

Jet Fuel: A refined petroleum product used in jet aircraft engines. It includes kerosene type jet fuel and naphtha-type jet fuel.

Methane: Hydrocarbon gas, which is the major component of natural gas.

Methanol: A light, volatile alcohol eligible for motor gasoline blending.

Methyl Tertiary Butyl Ether (MTBE): An ether, intended for motor gasoline blending.

Natural Gas: A gaseous mixture of hydrocarbon compounds, primarily methane, delivered via pipeline for consumption. It is used as a fuel for electricity generation, a variety of uses in buildings, and as raw material input and fuel for industrial processes. *Note:* This product, also referred to as *dry natural gas* or *consumer-grade natural gas*, is the product that remains after *wet natural gas* has been processed at lease facilities and/or natural gas processing plants. This processing removes nonhydrocarbon gases (e.g., water vapor, carbon dioxide, helium, hydrogen sulfide, and nitrogen) that would otherwise make the gas unmarketable and natural gas liquids.

Natural Gas, Dry: The marketable portion of natural gas production, which is obtained by subtracting extraction losses, including natural gas liquids removed at natural gas processing plants, from total production.

Natural Gas, Wet: A mixture of hydrocarbon compounds and small quantities of various nonhydrocarbons existing in the gaseous phase or in solution with crude oil in porous rock formations at reservoir conditions. The principal hydrocarbons normally contained in the mixture are methane, ethane, propane, butane, and pentanes. Typical nonhydrocarbon gases that may be present in reservoir natural gas are water vapor, carbon dioxide, helium, hydrogen sulfide, and nitrogen. Under reservoir conditions, natural gas and the liquefiable portions occur either in a single gaseous phase in the reservoir or in solution with oil and are not distinguishable at the time as separate substances.

Nitrogen Oxides (NO_x): Compounds of nitrogen and oxygen produced by the burning of fossil fuels.

North American Electric Reliability Council (NERC): A council formed in 1968 by the electric utility industry to promote the reliability and adequacy of bulk power supply in the electric utility systems of North America. The NERC consists of ten regional reliability councils and encompasses essentially all the power systems of the contiguous United States and Canada.

Nuclear Electric Power: Electricity generated by an electric power plant whose turbines are driven by steam generated in a reactor by heat from the fissioning of nuclear fuel.

Organization for Economic Cooperation and Development (OECD): Current members are Australia, Austria, Belgium, Canada, Czech Republic, Denmark and its territories (Faroe Islands and Greenland), Finland, France, Germany, Greece, Greenland, Hungary, Iceland, Ireland, Italy, Japan, Luxembourg, Mexico, the Netherlands, New Zealand, Norway, Poland, Portugal, South Korea, Spain, Sweden, Switzerland, Turkey, United Kingdom, and United States and its territories (Guam, Puerto Rico, and Virgin Islands).

Organization of Petroleum Exporting Countries (OPEC): Countries that have organized for the purpose of negotiating with oil companies on matters of oil production, prices, and future concession rights. Current members are Algeria, Indonesia, Iran, Iraq, Kuwait, Libya, Nigeria, Qatar, Saudi Arabia, United Arab Emirates, and Venezuela.

Photovoltaic Energy: Direct-current electricity generated from sunlight through solid state semiconductor devices that have no moving parts.

Pipeline, Natural Gas: A continuous pipe conduit, complete with such equipment as valves, compressor stations, communications systems, and meters, for transporting natural gas and/or supplemental gaseous fuels from one point to another, usually from a point in or beyond the producing field or processing plant to another pipeline or to points of use. Also refers to a company operating such facilities.

Pipeline, Oil: Oil and product pipelines (including interstate, intrastate, and intracompany pipelines) used to transport oil and petroleum products, respectively, within the 50 states and the District of Columbia.

Proved Reserves, Oil: The estimated quantities of all liquids defined as crude oil that geological and engineering data demonstrate with reasonable certainty to be recoverable in future years from known reservoirs under existing economic and operating conditions.

Proved Reserves, Natural Gas: The estimated quantities of natural gas that analysis of geological and engineering data demonstrates with reasonable certainty to be recoverable in future years from known reservoirs under existing economic and operating conditions.

Refinery (Oil): An installation that manufactures finished fuels from oil, unfinished oils, natural gas liquids, other hydrocarbons, and alcohol.

Renewable Energy: Energy obtained from sources that are essentially inexhaustible (unlike, for example, fossil fuels, of which there is a finite supply). Renewable sources of energy include conventional hydroelectric power, wood, waste, geothermal, wind, photovoltaic, and solar thermal energy.

Spot Price: The price for a one-time open market transaction for immediate delivery of the specific quantity of product at a specific location where the commodity is purchased “on the spot” at current market rates.

Strategic Petroleum Reserve (SPR): Petroleum stocks maintained by the federal government for use during periods of major supply interruption.

Stocks: Supplies of fuel or other energy source(s) stored for future use. Stocks are reported as of the end of the reporting period.

Sulfur Dioxide (SO₂): A toxic, colorless gas soluble in water, alcohol, and ether. Used as a chemical intermediate in paper pulping and ore refining, and as a solvent.

Transportation Sector: Private and public vehicles that move people and commodities. Included are automobiles, trucks, buses, motorcycles, railroads, and railways (including streetcars), aircraft, ships, barges, and natural gas pipelines.

Wellhead Price: The price of oil or natural gas at the mouth of the well.

Wind Energy: The kinetic energy of wind converted into mechanical energy by wind turbines (i.e., blades rotating from a hub) that drive generators to produce electricity.

Wood Energy: Wood and wood products used as fuel, including round wood (cord wood), limb wood, wood chips, bark, sawdust, forest residues, charcoal, pulp waste, and spent pulping liquor.



BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c))
Emergency Order: Transalta)
Centralia Generation LLC)
_____)

Order No. 202-25-11

Motion to Intervene, Motion for Clarification, and Requests for Rehearing and Stay
of Sierra Club, NW Energy Coalition, Washington Conservation Action, Climate
Solutions, Public Citizen, and Environmental Defense Fund
(collectively, “Public Interest Organizations” or “PIOs”)

Exhibit 1-100:
Seattle Times Article

The Seattle Times**Climate Lab****The Seattle Times**

Centralia coal plant to burn natural gas instead

Dec. 11, 2025 at 10:00 am | Updated Dec. 11, 2025 at 10:01 am



Mount Rainer appears behind the TransAlta Centralia Coal Plant during sunset on April 27, 2023. (Daniel Kim / The Seattle Times file)

By **Amanda Zhou**

Seattle Times climate reporter

CLIMATE LAB

Climate Lab is a Seattle Times initiative that explores the effects of climate change in the Pacific Northwest and beyond. The project is funded in part by The Bullitt Foundation, CO2 Foundation, Jim and Birte Falconer, Mike and Becky Hughes, Henry M. Jackson Foundation, Martin-Fabert Foundation, Craig McKibben and Sarah Merner, University of Washington and Walker Family Foundation, and its fiscal sponsor is the Seattle Foundation.

Washington state's last coal plant, which was scheduled to close at the end of this year in Centralia, will be converted to burn natural gas.

Power generation company TransAlta announced Wednesday the facility, which will have a capacity of 700 megawatts, will be converted in partnership with the state's largest utility, Puget Sound Energy.

The deal will give PSE exclusive rights to the plant's energy generation. The plant is scheduled to come online in late 2028 and operate through 2044, according to TransAlta. The price of the conversion is estimated at \$600 million and the agreement between TransAlta and PSE is subject to review by the Washington Utilities and Transportation Commission, according to the company.

According to PSE spokesperson Christina Donegan, the plant will meet about half of the utility's 2030 summer peak demand needs and about 30% of the utilities expected 2030 winter peak demand needs.

The coal plant was originally scheduled to close by the end of this year in accordance with a 2011 agreement between the state and TransAlta, which is based in Calgary, Alberta. The company has owned and operated the 11,000-acre property since 2000.

The coal plant's second unit has around 670 megawatts of capacity, according to TransAlta, though PSE has relied on the plant for around 370 megawatts.

According to TransAlta, the conversion to natural gas, which is mostly methane, will lower the "emission intensity profile" of the facility. The coal-fired power plant has been the state's largest source of greenhouse gas emissions.

The announcement comes as increasing [electricity demand and coal](#) retirements across the Northwest have driven up the risk of rolling blackouts during extreme weather events like cold snaps and heat waves due to insufficient power generation.

All Washington state utilities are also required to stop using coal-fired electricity after this year, which is required by the Clean Energy Transformation Act. The landmark climate law also calls for utilities to become greenhouse gas "neutral" by 2030 and have emission-free electricity by 2045 or risk steep fines.

While Puget Sound Energy has been ramping up renewables, adding resources like the [Beaver Creek wind farm](#) in Montana, only around 50% of the utilities electricity came from renewables in 2024 and is below target to meet the state's clean energy goals.

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