BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c) Emergency Order: Midcontinent Independent System Operator and Northern Indiana Public Service Company LLC	)))))	Order No. 202-26-19
Federal Power Act Section 202(c) Emergency Order: Midcontinent Independent System Operator and CenterPoint Energy Indiana South	))))	Order No. 202-26-20

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

Exhibit 51
2023 Energy Innovation Coal Cost Report

Coal Cost Crossover 3.0: Local Renewables Plus Storage Create New Opportunities for Customer Savings and Community Reinvestment

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EXECUTIVE SUMMARY

The cost of operating existing coal power plants in the United States continues to increase while coal jobs, generation, and mining all decrease.[i] New coal retirement announcements seem to happen faster, even as natural gas prices skyrocket, and renewable energy prices keep dropping.

The Inflation Reduction Act (IRA), which extended and expanded clean energy tax credits, along with new funding to guarantee loans for refinancing fossil assets and reinvesting in clean energy infrastructure, has shifted the economic scale even further toward wind and solar. But it also creates thoughtful new investment opportunities in areas burdened by existing coal plants with a 10 percent tax credit boost for projects located in nearby communities.

These factors underpin the third iteration of our Coal Cost Crossover analysis, which shows wind and solar energy are unequivocally cheaper than coal-fired generation across the country. This study finds 99 percent of all coal-fired power plants in the U.S. are more expensive to operate on a forward-

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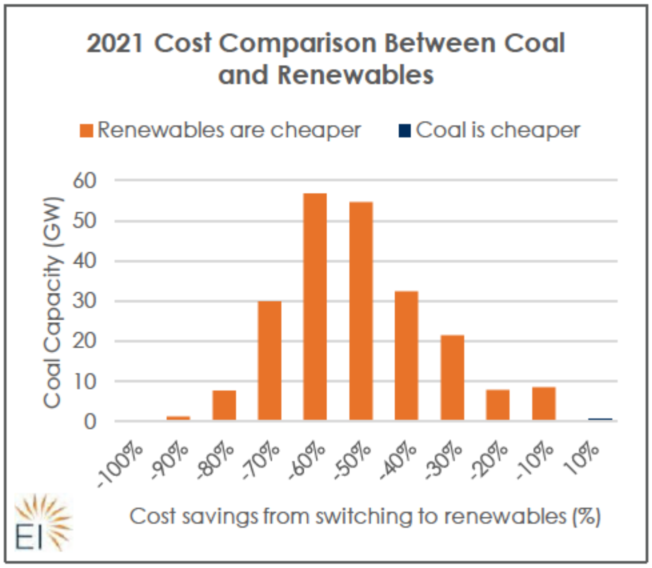
looking basis than the all-in cost of replacement renewable energy projects, and 97 percent are more expensive than renewable energy projects sited within 45 kilometers (approximately 30 miles), a significant acceleration from our two previous analyses. For more than three quarters of U.S. coal capacity, the all-in cost per MWh of the cheapest renewable option is at least a third cheaper than the going-forward costs for the coal it would replace.

In this report we compare the cost of operating each continental U.S. coal plant in 2021, totaling 220 gigawatts (GW) of coal capacity across the country, to the estimated costs of building new wind and solar generation. We consider the wind and solar costs within two geographic scopes: local to the coal plants (within 45 kilometers) and regionally (roughly within the utility balancing area), finding that nearly all existing coal plants have multiple lower-cost clean energy replacement options.



This research shows all but one of the country's 210 coal plants are more expensive to operate than either new wind or new solar. If the IRA's new energy community tax credit is included in the equation, 199 of the 210 plants are more expensive to operate compared to local solar resources sited within 45 kilometers of the plant. Local wind resources are also cost-effective and readily available, with 104 plants having cheaper wind resources within 45 kilometers.

Altogether, 205 plants have local renewable options that would be cheaper than coal-fired electricity. This potential to replace existing coal plants with cheap, local clean energy generation creates significant economic benefits for community transition. Our analysis finds replacing these plants with local solar or wind would drive $589 billion in local capital investment that could support economic diversification, job creation, and tax revenue.

These local wind and solar resources could also help solve the problem of long interconnection queues—a significant barrier to renewables deployment. Renewable projects built near a retiring coal plant could use the existing plant's interconnection, helping to further lower costs. If more policymakers consider this dynamic, they can streamline economic replacement and anticipate coal retirements, which are accelerating due to the cost dynamics analyzed in this report.

While solar and wind replacement resources provide significant low-cost energy and reliability value to the grid, savings generated by switching from more expensive coal to cheaper clean energy can finance other resources to provide additional energy and reliability value.

We find that the savings generated by shifting to local solar could fund the addition of 137 GW of four-hour batteries across all plants, and 80 percent or more of the capacity at a third of existing coal plants – the economics of replacing coal with renewables are so favorable that they could fund a massive battery storage buildout to add reliability value along with emissions reductions. However, it is important to remember reliability is a system attribute—replacement renewable portfolios need not bear sole responsibility for replacing the reliability services of individual coal plants.

While the economic case is clear and virtually universal, barriers remain to replacing coal with clean energy, and policymakers must act to unlock the cost savings and human health benefits for coal communities while reducing climate pollution.

Several policies can enable a faster coal-to-clean transition. Specifically:

- To prepare the way for coal transition, regulators and system operators should:
    - Improve methods to assess reliability and resource adequacy reflecting the reliability value of renewable portfolios and valuing the reliability attributes of a high-renewables grid.
    - Update interconnection study rules to leveraging existing coal plant interconnection rights to speed grid connection processes for local renewable replacement resources.
- To proactively pursue the transition, regulators should:
    - Encourage utilities to utilize IRA financing programs available through the Departments of Energy and Agriculture to remove financial barriers to coal community economic transition and investment.
    - Enable competitive resource procurement.
    - Require re-assessment of any utility investment plan, including integrated resource plans and market-based solicitations for renewable supply, completed prior to IRA as renewables costs are now out of date.
- To create a just transition for affected communities, state legislatures and energy offices should:
    - Plan for and fund a coal community-centered economic transition, where local clean energy resources are the anchor for a more expansive economic transition plan.

ACKNOWLEDGEMENTS

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INTRODUCTION

The U.S. power sector is in transition, with coal-fired power generation falling to 55 percent of its 2007 peak in 2021. This transition is also decreasing the number of coal mines, power plants, and workers. Over the same period, utility-scale solar and wind generation have increased more than

18,000 percent and 1,000 percent, respectively, as costs declined by 90 percent for solar and 72 percent for wind.[1,ii]

In 2019, Energy Innovation Policy & Technology LLC® partnered with Vibrant Clean Energy to compile and analyze a 2018 dataset of capital, operations and maintenance, and fuel costs for coal, wind, and solar. Our first Coal Cost Crossover report found that 62 percent of existing coal capacity was uneconomic compared to producing the same amount of energy with new local wind or solar. To make this comparison, we evaluated the marginal cost of running each coal plant with the levelized cost of new wind and solar, where the levelized cost of energy (LCOE) is the cost of building and operating a new resource divided by its energy production over its lifetime. The analysis projected that by 2025, more than 80 percent of the coal fleet would be unable to compete against new renewables or would be retired, even without federal incentives.[2]

In 2021, we completed a similar analysis of 2019 data that considered the National Renewable Energy Laboratory's (NREL) 2018 Annual Technology Baseline (ATB) forecast showing steep cost declines for solar and wind energy, as well as an extension of the federal investment tax credit for solar coupled with a continued production tax credit for wind. The Coal Cost Crossover 2.0 report found that the coal crossover had significantly expanded, with 72 percent of coal capacity and 80 percent of plants already more expensive to run compared to either new solar or wind, including tax credits in effect.[3]

This Coal Cost Crossover 3.0 report uses new 2021 data to reevaluate the coal crossover economic dynamic. Since our 2.0 report, solar and wind costs continued fall, coal prices kept rising, and coal plant capacity factors continued decreasing, all continuing the trends observed between 2017-2019.[iii]

Now, new federal tax credits in the IRA make the economic case for replacing coal with clean energy unequivocal. IRA incentive bonuses for clean energy projects located near retired coal infrastructure offer new, additional savings and reinvestment opportunities. This report combines elements of the previous two studies, analyzing both regional and local renewable resources, but now accounts for the new incentives.[4] Given the IRA's expanded tax credits, we find all coal plants but one are more costly to run compared to new wind and solar energy, and all but five are more expensive than wind or solar sited within a 45 kilometer (km) radius.

Of course, examining relative economics using levelized cost faces limitations. The overall value of these power plants depends on much more than just cost. While the coal cost crossover describes a scenario in which renewable resources replace coal generation on a one-to-one basis, the reality is that coal retirement is a complex process that depends on the reliability needs of the local and

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[ii] Coal generation decreased from 2,016,455 gigawatt-hours (GWh) in 2007 to 875,885 GWh in 2021. Solar generation increased from only 612 GWh in 2007 to 115,258 GWh in 2021. Wind generation increased from 34,449 GWh in 2007 to 378,196 GWh in 2021. In total, coal generation was still higher in 2021 than wind and solar in the U.S. by 382 GWh.
[iii] Renewable costs continued to fall through 2021, the year we used for this analysis. Costs across the energy industry rose in 2022 due to supply chain constraints but are expected to fall again as supply issues ease.

regional electricity grid, which in turn, depends on the entire resource portfolio's dynamics. For example, in some regions one-to-one replacement with a combination of wind and solar resources may not adversely affect reliability. In others it may, depending on what other resources are serving the power grid.

Many communities also depend on coal plants for jobs and tax revenue. In addition to reliability value, policymakers must consider the potential of replacement energy resources to provide similar economic value. The new IRA incentives to locate replacement resources in the same communities where coal plants sit can contribute to a sustainable, economic transition. As we show in this report, these incentives fundamentally improve the prospect for coal communities to benefit from new clean energy resource development.

This report traces the shifting role of coal in the U.S. power sector and identifies key changes in the economics of coal-fired electricity generation due to the IRA's passage. We explain our coal cost crossover calculations, including how we compiled the coal dataset using publicly available data, and how we calculated the LCOE for both local and regional wind and solar using open-source modeling tools developed by NREL.

Four scenarios compare new renewable generation costs to marginal coal costs: regional wind, regional solar, local wind, and local solar, effectively assessing the replacement of every unit of energy produced by the coal plants. For the local solar scenario, we also analyze the economics of adding four hours of battery storage capacity to the solar resources. This analysis demonstrates a clean alternative to coal generation with added reliability value and an opportunity for local investment and economic diversification.

Finally, we provide policy recommendations to help policymakers successfully transition away from polluting, higher cost coal power to cheaper, clean energy. Because the IRA aligns the aims of least-cost electricity planning and procurement with an economic transition for coal communities, we highlight the opportunity for gradual economic transition centered around replacing coal generation with local renewables and storage. Local replacement also has the advantage of potentially being able to leverage existing grid interconnection rights. We describe how utilities can directly take advantage of key IRA provisions, as well as how policymakers can ensure utilities account for the changing economic landscape in their planning and procurement. We also explain how just transition planning, accurate reliability assessments, and transmission buildout can speed up and smooth out coal's phaseout in the U.S.

COAL'S ROLE IN THE U.S. POWER SECTOR

Coal-fired power was the bedrock of a reliable, affordable U.S. power sector for nearly a century. But since 2010, coal generation has declined 52 percent, and renewable power generation exceeded coal generation for the first time in 2020. In 2011, the U.S. had 317.6 GW of coal-fired electricity generation capacity,[5] but that number fell to 221 GW in 2021. Nearly a quarter of the remaining fleet is slated for retirement by 2029.[6]

Several factors explain this decline, including pollution control standards requiring costly retrofits, cheap natural gas and renewable power, state clean energy policies, and improved building and industrial efficiency.[7] Coal's decline has been accompanied by a precipitous fall in coal industry employment.[8] But even as employment fell, reduced pollution from coal plants dramatically improved public health. Annual deaths attributed to air pollution from coal plants fell from 30,000 deaths in 2000 to less than 3,000 in 2019.[9]

Coal's role in electricity system reliability has shrunk considerably. Coal-fired power plants operate as part of an integrated power system where supply and demand must remain in constant balance. The decline in coal-fired generation and capacity, and replacement by a more diverse portfolio of gas and renewable power plants with vastly different operational characteristics indicates that coal is not necessary for reliable power systems. For example, the United Kingdom reliably operated its grid without any coal generation for two straight months in 2020.[10]

The role of coal plants and their operation in the electricity system has also changed over time. Historically, coal plants operated as "baseload" power plants, relying on a relatively low-cost fuel supply to run at a constant, high output. But now markets are pushing coal plants to operate more variably, ramping up and down as the economics and availability of renewable energy fluctuate throughout the day and over a season.[11] Coal plants in our dataset had an average capacity factor of 46 percent, which means they ran, on average, only 46 percent of the time. This on-again, off-again operation increases wear and tear on coal plants designed for a different operating paradigm.

Displacement by cheaper gas and renewables means baseload operation is increasingly unprofitable for existing coal—operating at high output when plentiful clean energy resources operate at zero marginal cost is a waste of fuel. According to RMI, since 2012 utilities could have saved customers $1–$2 billion per year by turning down coal and relying on lower-cost, less polluting resources. This is partially due to self-scheduling, a practice through which monopoly utilities uneconomically run their coal plants in wholesale markets and charge captive customers the difference.[12]

Replacing coal with clean energy is not a one-to-one exercise. System operators and utilities only gain confidence that coal retirements won't adversely affect system reliability by evaluating the reliability of the entire energy portfolio. A recent North American Electric Reliability Corporation (NERC) assessment highlighted the need to build new generation before retiring old generation when reliability risks are present.[13] But recent studies such as the 2030 Report, which found an 80 percent clean, coal-free electricity system to be both reliable and affordable, confirm we can maintain a dependable electricity system without coal.[14]

The U.S. will continue relying on coal plants for reliability until we add enough new clean resources (including demand-side resources and transmission) to replace their reliability and energy services.

The Coal Cost Crossover 3.0 analysis highlights opportunities to economically displace coal-fired generation and replace those services in part. With the IRA's passage, the economic case for shifting from coal to renewables is stronger than ever.

INFLATION REDUCTION ACT IMPACTS ON U.S. ENERGY ECONOMICS

The IRA will significantly affect the relative economics of coal and clean power in the U.S. In this analysis, the IRA's extended and improved tax credits, along with a pair of refinancing programs, have the greatest effect on the cost of coal compared to renewables.

Tax Credits

Clean energy tax credits have arguably been the most important federal climate policies to date, driving nationwide solar and wind growth. The IRA builds upon this successful policy to make the clean energy transition cost effective for the long term, with earlier Energy Innovation® analysis finding the credits to be the most impactful IRA provision for electricity sector decarbonization.[15]

The production tax credit (PTC) and investment tax credit (ITC) are the IRA's two key tax credits for new clean electricity resources. Historically, the PTC has primarily supported wind energy resources, and at its full value paid approximately $26 per megawatt-hour (MWh) in 2022 dollars over the first 10 years of a wind project's commercial operations.[16] The ITC has largely supported solar resources, and at its full value offered a tax credit for 30 percent of total system cost, paid out when it is first placed in service. Prior to the IRA's passage, the PTC had expired, and the ITC had begun phasing out with a value of 26 percent for projects starting construction in 2022.[17] The IRA created long-term certainty for these tax credits, with the extension lasting through 2032 or until electricity sector greenhouse gas (GHG) emissions fall 75 percent below 2022 levels, whichever is later.

The IRA also immediately revived a long-expired option for solar projects placed in service in 2022 or later to elect the PTC instead of the ITC, which ensures that tax credits will stay impactful as solar capital costs continue to fall. In addition, the IRA provides an ITC for stand-alone energy storage technologies placed in service in 2022 or later, removing prior restrictions that required storage to be co-located with and charged primarily from solar energy resources.

Beyond the extension and increased flexibility, the IRA created several human impact bonuses that increase the value of the tax credit. To qualify for the full credit, a project must meet prevailing wage and apprenticeship requirements. Additionally, a project can earn a 10 percent boost for meeting domestic content requirements and an additional 10 percent for locating the project in an energy community (which includes census tracts in which coal-fired power plants have been retired since 2009 and adjacent census tracts, as defined by the IRA, see Figure 1).[iv]

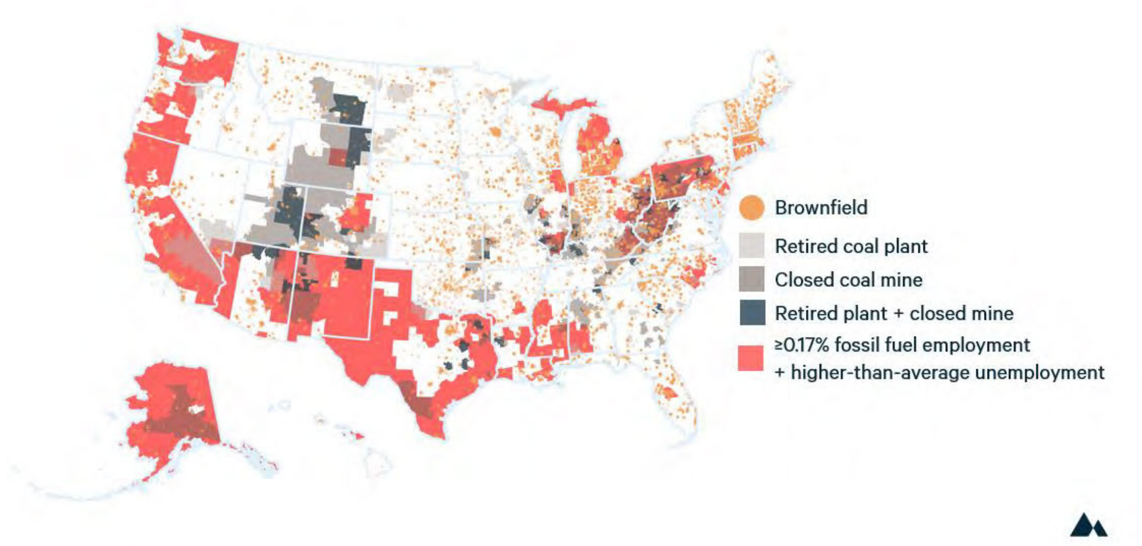

Figure 1. Map of probable energy communities, as defined by the IRA. Source: Resources for the Future.[18]

The combined impacts of energy community, labor, and domestic content bonuses reshape solar economics in coal communities. The median cost of new solar in these communities is about \$24/MWh with low variance, while the median marginal cost of coal is \$36/MWh with higher variance (see Figure 2). As discussed later in this report, this cost differential provides significant headroom for additional battery storage, which can also qualify for energy community bonuses.

[iv] The 10 percent credit boost for siting projects in energy communities works slightly differently for the ITC and PTC, providing a 10-percentage point ITC bonus and a 10 percent bonus on the PTC credit value.

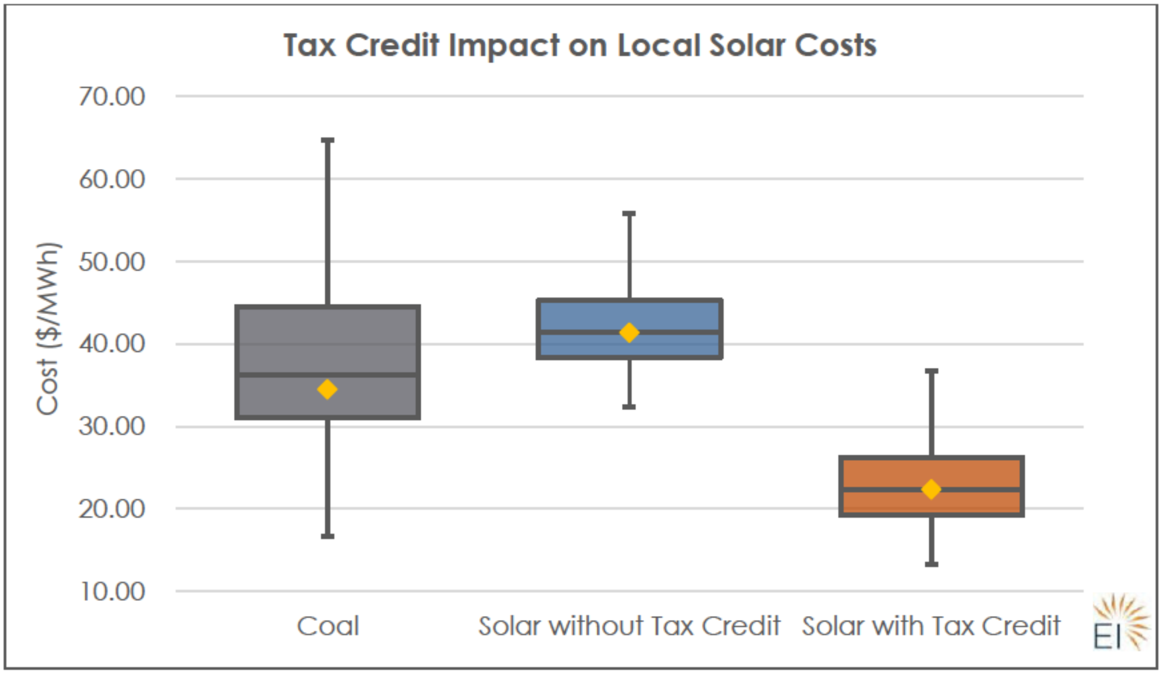

Figure 2. Impact of tax credits on local solar LCOEs in our analysis, including the energy community bonus. The yellow diamond indicates the average cost of each resource (weighted by generation). With the IRA, the economic case for local solar becomes unequivocal.

Revinvestment Financing

The PTC and ITC play the crucial role of decreasing the cost of developing clean electricity resources, but upfront cost is far from the only barrier to moving from coal generation to clean alternatives. One of the biggest hurdles to this transition is the rate impacts of adding large capital investments to utility rates when billions are still owed to debtors and investors on uneconomic coal assets. But a new IRA financing program to invest in clean energy infrastructure in current or former coal communities can overcome this hurdle. As the program only lasts until 2026, time is of the essence.

Most U.S. coal capacity is owned and operated by monopoly utilities, which collectively hold at least $176 billion in unpaid fossil plant balances[v]—accounting ledgers that represent the debt and equity capital structures utilities used to finance these plants over time. Utilities include this capital cost in electricity rates, typically recovered over the plant's entire lifetime in a financial arrangement somewhat similar to a conventional 30-year mortgage (albeit one that is continuously extended as new capital is invested at coal plants). As long as the plant remains in operation or until the investment is fully depreciated, customers are generally obligated to continue to cover these costs, which include substantial returns for utility shareholders. Without a change to this structure, monopoly utilities have little to gain from early coal plant retirement and they may perceive retirement or partial replacement as putting cost recovery at risk.

New IRA programs provide flexible, low-cost financing to clean up utility balance sheets by reducing the cost of investing in new local clean energy infrastructure, including wind, solar, batteries, transmission infrastructure, and reuse of the coal plant itself. Utilities and other power plant operators, such as independent power producers, can access low-cost government-backed loans to reduce the rate impacts associated with large capital expenditures required to transition from coal to clean and stimulate local economic development. The IRA created two novel programs to support utilities in transition:

First, the IRA appropriated $5 billion to the U.S. Department of Energy's (DOE) Loan Programs Office (LPO) via the Energy Infrastructure Reinvestment (EIR) program to support $250 billion in loan-making authority to facilitate refinancing and reinvestment in capital projects at fossil infrastructure sites, using below-market interest rates. Funds can be used flexibly to "re-tool, re-power, re-purpose, or replace" fossil infrastructure across the entire energy industry (including non-utilities), reducing the cost of replacement resources and creating numerous pathways for community diversification and redevelopment. The financing provisions are flexible enough to work for all parties—utilities, consumers, and communities. These stakeholders can use the financing to reduce the near-term rate impacts of capital transition, allowing new investment to arrive sooner in these communities that sorely need it as aging fossil plants ramp down.

Second, the IRA authorized a $9.7 billion program specifically for rural electric cooperatives through the U.S. Department of Agriculture (USDA). Rural electric cooperatives provide electricity to more than 40 million people. Their power supply is particularly coal-heavy, with coal accounting for 28 percent of generation in 2020 compared to 19 percent nationwide.[19] This means surrounding rural communities bear a disproportionate burden of coal-related pollution, while member-owned cooperative customers remain tethered to coal debt. While members may want to transition to clean energy to capture pollution and cost savings, this debt holds them back. Furthermore, simply shutting down cooperative coal plants could impact communities that rely on relatively high-paying jobs where economic opportunities are sparse. To address these challenges, the IRA funds USDA to provide direct grants or loans for rural electric cooperatives to procure clean energy, with an express purpose of reducing GHG emissions.

METHODOLOGY

As in the previous two coal cost crossover studies, this report compares the marginal cost of energy (MCOE) for existing coal plants across the U.S. with the LCOE for solar and wind. We compare the same coal costs to four different cost scenarios for renewables. Scenarios vary by resource type (wind or solar) and by geographic scope (regional or local). For the first two scenarios, regional solar and regional wind, we separately examine the costs of solar and wind located within the same region as a given coal plant, calculating the LCOE to replace each plant's annual generation within a nearby region that corresponds roughly to the utility's service territory.[vi]

For the last two scenarios, local solar and local wind, we look at local costs for solar and wind separately, calculating the cost if all replacement renewables are sited within a 45 km radius of the existing coal plant. Local solar and wind projects get the additional energy community tax credit bonuses in the IRA, which helps to offset losses in power resource quality due to the local siting constraint. A more detailed explanation of our methodology is available in this report's Appendix.

Coal Economics

To calculate the MCOE at each coal plant, we sum three cost components: the cost of fuel, the fixed and variable costs of operations and maintenance, and the going-forward routine capital expenditure costs, each calculated on a per-MWh basis. Using 2021 U.S. Energy Information Administration (EIA) data, we calculate the total going-forward marginal cost for all coal plants operated by utilities or independent power producers in the continental U.S., excluding plants that are used for co-generation of heat. These costs appropriately comprise marginal cost because they would not be paid if the coal plant retired. By contrast, we do not include unpaid capital balances as part of the MCOE because their payment does not depend on whether the plant retires.[vii]

Renewable Economics

We used NREL's Regional Energy Deployment System (ReEDS) model to calculate solar and wind LCOE values, which are all-in estimates of the cost of energy output in MWh, taking into account all capital expenditure, operations, and maintenance costs. We used the 2021 actual cost values from the 2022 NREL ATB.

The ReEDS model uses solar and wind resource potential values at around 50,000 sites across the country, accounting for comprehensive exclusion criteria, including land cover, elevation, slope, environmentally sensitive areas, and local siting regulations. The model also provides annual capacity factors at each of these sites. The site-specific LCOE is then calculated based on capacity factor, as well as a comprehensive list of parameters including capital costs, fixed operation and maintenance costs, equity costs, interest rates, construction costs by location, construction period,

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[vi] We use regions defined by NREL's Regional Energy Deployment System model, explained in detail in the appendix.
[vii] These remaining balances are the primary target of the reinvestment programs created by the IRA. Though we don't include the balances in our cost calculations, the potential to refinance and replace with clean energy is another path toward reducing coal generation beyond operating costs.

IRA tax credits, and depreciation. We calculate the LCOE after accounting for both the ITC and PTC 2022 tax credit values, using the cheaper of the two.

Renewables key assumptions

Across the four renewable scenarios, we make several key assumptions:

- Regional solar and wind costs include new grid interconnection costs, while local resources do not.
- All renewable resources qualify for the prevailing wage and apprenticeship hour tax credit bonus.
- All wind resources qualify for the full domestic content bonus, while 42 percent of solar resources qualify for the domestic content tax credit bonus based on current domestic content levels.[20]
- Storage does not qualify for the domestic content credit bonus.
- All tax credits are reduced by 10 percent to account for transfer losses.

Regional renewables scenarios

For the two regional renewable cost scenarios, regional wind and regional solar, we start by finding the LCOE for regional wind and solar that could replace each plant's 2021 annual generation. The region we study for each plant is based on the ReEDS balancing area (of which there are 134, see Appendix) in which the plant is located, corresponding roughly to the utility territory. For each coal plant, we sort the wind and solar sites available in that region by LCOE and choose the best sites based on capacity factor to replace the coal generation. For selected sites within each region, we capacity-weight the site-level LCOEs to estimate the weighted average regional LCOE. Interconnection costs associated with transmission lines that connect the project to the grid are also added into these LCOEs, while we make no assumption about broader grid impacts.

Local renewables scenarios

For the local wind and local solar scenarios, we first determine the viability of the local wind or solar replacements for each coal plant. Using the plant's latitude and longitude as the center, we create concentric circles around each coal plant, starting with a radius of 5 km and moving up to 45 km in 5 km increments. We identify the solar and wind sites that fall within each of these concentric circles and separately estimate the site-level capacity and annual generation potential for solar and wind resources. We then estimate the minimum radius needed to replace the annual generation from each coal power plant with solar or wind resources.

If there is enough generation found within the 45 km radius, we then determine the local LCOE by capacity-weighting the site-level LCOEs for the maximum radius needed to match the existing plant's generation. For solar, nearly all plants meet the generation requirement within a 20 km radius while for wind, the average radius is much larger and there are many plants without enough wind generation within 45 km because of the more site-specific nature of wind energy potential and the larger land footprint (see Figure 3).

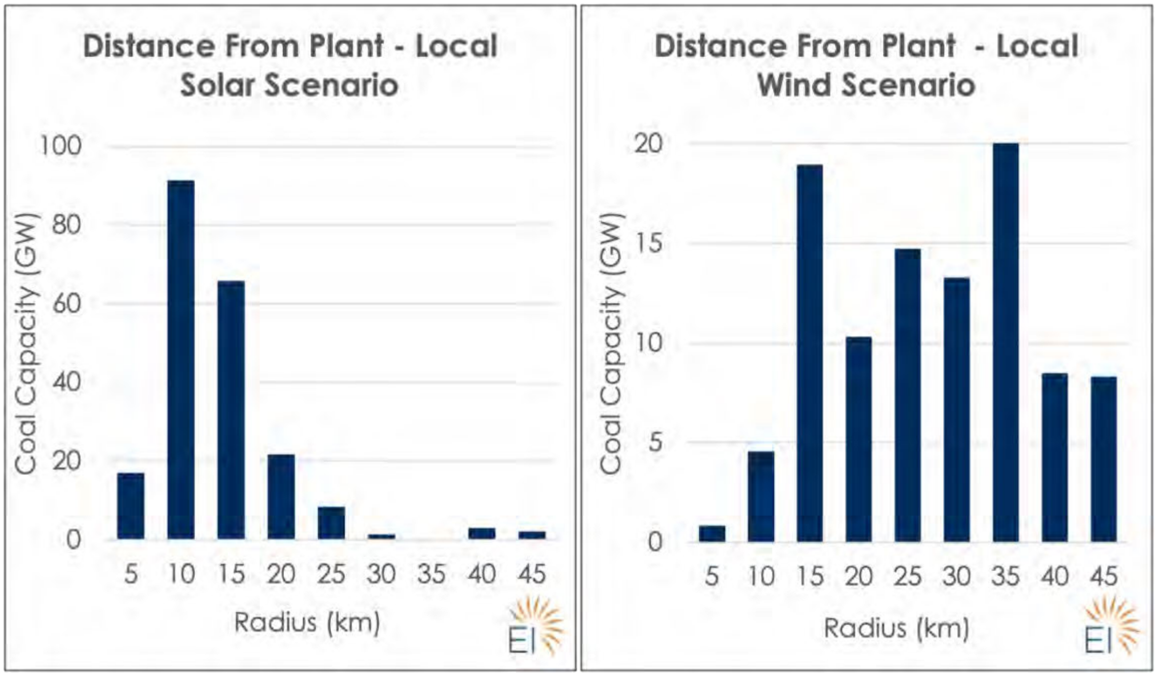

Figure 3. This figure plots the radius needed to match each plant's generation, while still being cheaper than coal, for both local solar and local wind. The majority of coal capacity has enough solar potential within a 20 km radius to meet the plant's entire annual generation in our local analysis and still provide cheaper energy than coal. While many plants have sufficient and cost-effective local wind nearby, less potential is available in close proximity for local wind.

For the local scenarios, we assume that all projects sited within 45 km of the plant will receive the IRA's 10 percent energy community bonus tax credit, given that both the census tract and neighboring census tract to any retiring coal plant fit the IRA's definition of an energy community. For these scenarios, interconnection costs are not included in the LCOEs as we assume that the new resources can utilize the existing plant's interconnection infrastructure.

Storage analysis

For the local solar scenario, we also analyze the economic feasibility of installing four-hour battery storage capacity along with the solar to provide additional reliability services to the grid. For this analysis, we start with a $330 per kilowatt-hour (kWh) price for the storage,[viii] and we include a 36

[viii] This price is based on the 2021 actual storage costs in the NREL 2022 ATB.

percent ITC (the full credit plus the energy community bonus, minus transferability losses). After calculating the savings from replacing the coal generation with local solar generation, we then determine how much battery capacity those cost savings would fund. Due to uncertainty in the battery price going forward, we calculate the battery capacity funded for storage prices ranging from $100 to $400/kWh.

RESULTS & DISCUSSION

Main findings:

1. >99 percent of plants studied are more expensive to run than to replace with new renewable wind or solar energy.
2. >97 percent of plants studied are more expensive to run than to replace with either local solar or local wind energy within 45 km (approximately 30 miles) of the coal plant.
3. Replacing coal generation with local solar resources could drive up to $589 billion in clean energy investment in energy communities across the U.S.
4. Replacing coal generation with local renewable resources could save enough to finance installation of 137 GW of four-hour battery storage—62 percent of the coal fleet's nameplate capacity.

Overall comparison between coal and renewable costs

For this report we combined elements of the two previous Coal Cost Crossover reports: We looked at replacing coal power with regional wind or solar resources *and* at replacing coal power with local wind or solar resources close enough to a plant to take advantage of its transmission connection and the energy community bonus tax credit. Across these four scenarios, we found that:

- 199 plants are more expensive to run than to replace with regional wind.
- 190 plants are more expensive to run than to replace than regional solar.
- 104 plants are more expensive to run than to replace than local wind.
- 199 plants are more expensive to run than to replace than local solar.

Analyzing these scenarios together, we found all but a single coal plant[ix] in the dataset of U.S. coal plants to be more expensive (lower renewable LCOE than coal MCOE) compared to replacement by at least one of these renewable options. Between local solar and local wind, 205 out of 210 plants had at least one cost-effective local renewable option. Of these, 98 had *both* local solar and local wind options that were cheaper than coal (see Figure 4). This represents a sharp acceleration

[ix] The single coal plant is the Dry Forks Station in Wyoming. It is the newest and among the cleanest coal plants in the U.S. coal fleet and is still only $0.32/MWh cheaper to operate than available regional wind. It is also a testbed for carbon capture use and storage (see https://www.powermag.com/dry-fork-a-model-of-modern-u-s-coal-power/). A similar plant built today would include capital costs and would not be competitive with new renewables.

in the previously observed trend in our coal cost crossover reports (see Figure 5). The full results of all four scenarios can be viewed in the accompanying spreadsheet.

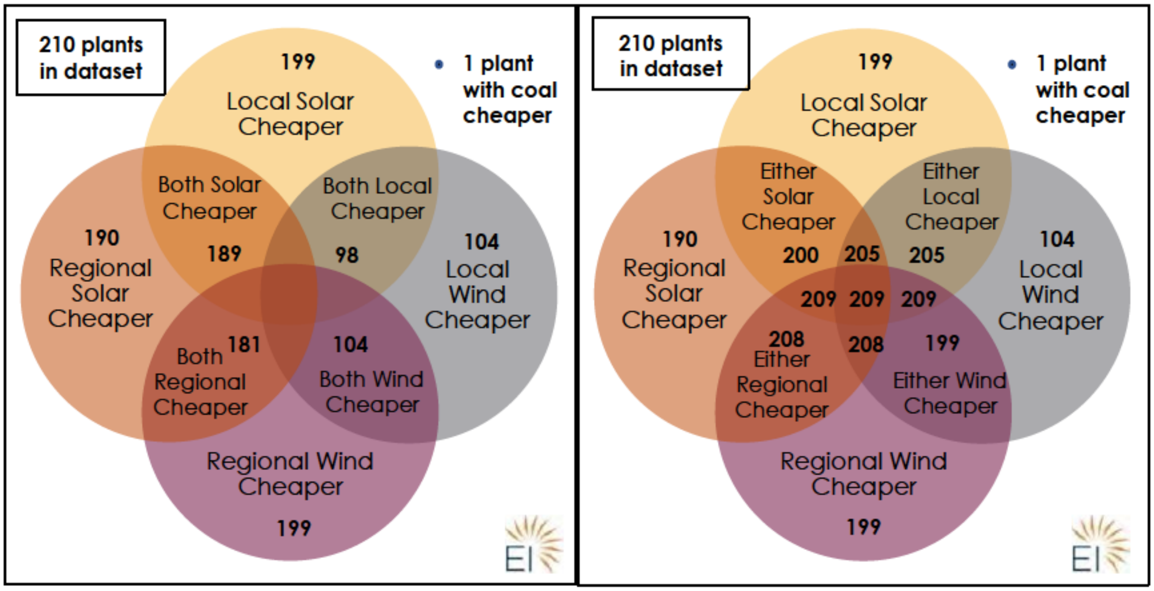

Figure 4. A closer look at the 210 coal plants in our data set based on the specific comparison with renewables that was made. The Venn diagram on the right looks at inclusive intersections (either resource is cheaper than coal) while the one on the left looks at exclusive intersections (both resources are cheaper than coal). We did not analyze any hybrid combinations of wind and solar, although this is clearly a possibility in the local context (98 plants) and the regional context (181 plants).

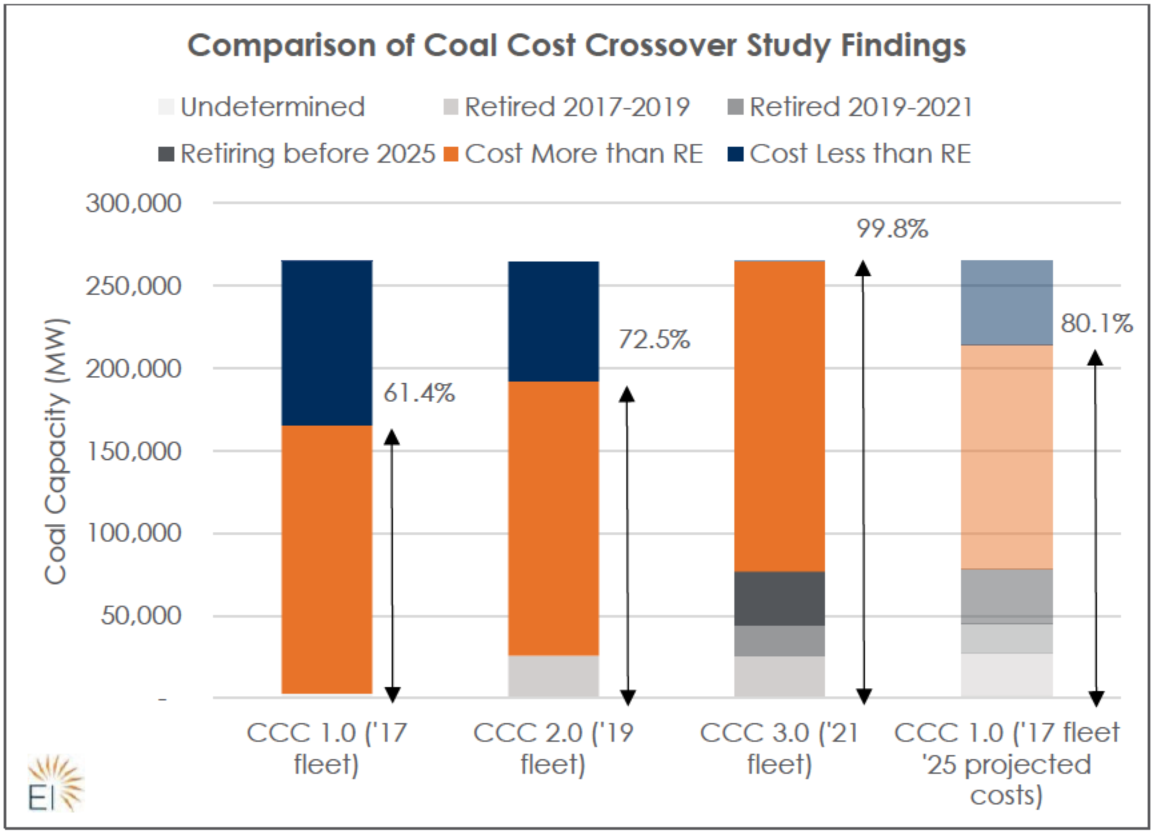

Figure 5. Comparison of our two original analyses of renewables and coal cost-competitiveness. The first included a 2025 projection for renewable costs to compare with 2017 coal going-forward costs. This comparison highlights how much the trend for coal being uneconomic compared to replacement by renewables has accelerated since the first report published in 2019.

Comparison between coal and cheapest available wind or solar resource

For the plants that were uneconomic, multiple renewable options were less expensive than coal generation, but regional wind and local solar were most frequently the cheapest overall resources (see Figure 6 and Figure 7). Regional wind was the cheapest option for 117 plants, while the most economic resource was local solar for 75 plants, local wind for 13, and regional solar for only four.

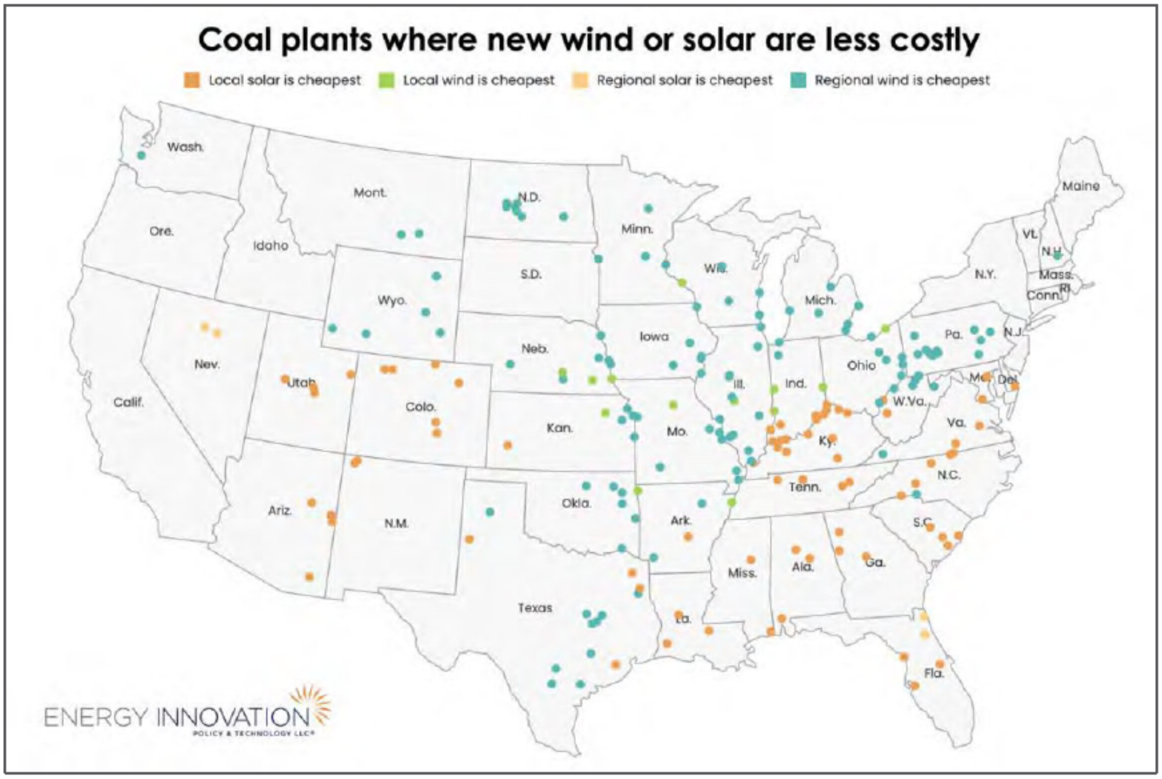

Figure 6. While most plants have multiple cheaper renewable options, the overall cheapest renewable resource varies by geography.

Notably, for solar, local replacement is cheaper than regional replacement in many cases due to low regional cost variability, lower transmission spur line costs,[x] and IRA energy community bonuses. For regional versus local wind, however, regional resources tend to be cheaper even with the added costs due to higher variation in resource quality for wind—going further from the plant often yields significantly better wind energy sites.

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[x] A "spur line" is the transmission line that connects a renewable project to the bulk system at a point of interconnection. In this analysis, we do not make assumptions about interconnection costs beyond the cost of building the spur line. In this limited respect, we anticipate that local wind and solar costs would be lower than regional renewables, because local renewables are adjacent to the coal plant's point of interconnection. We recognize that interconnection costs for renewables have been increasing for a variety of reasons as they sit in ever-growing interconnection queues around the country, but also hypothesize that some renewables could reuse existing coal plant interconnection rights with very low interconnection costs. See https://emp.lbl.gov/news/pjm-data-show-substantial-increases.

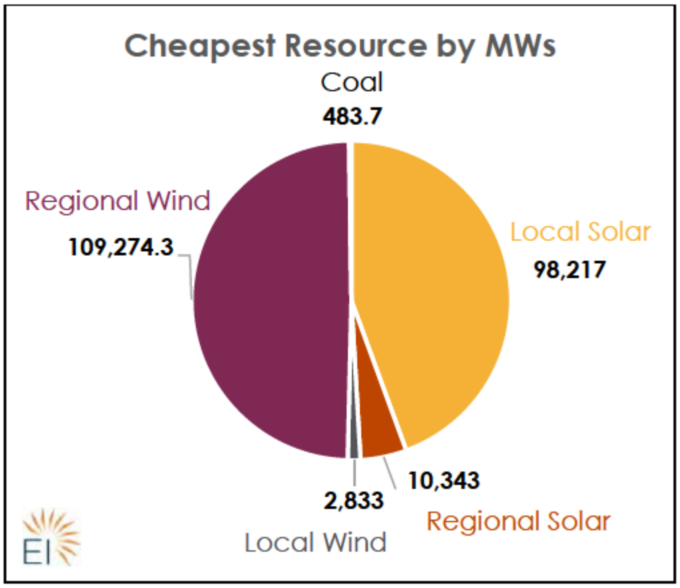

Figure 7. This chart shows the cheapest renewable resource option for each MW of coal capacity studied in this report. Local solar and regional wind are the cheapest renewable resources for nearly all plants.

We still see a wide range in the relative economics between existing coal and new wind or solar, with the all-in costs for the cheapest renewable option anywhere from zero (for one plant) up to 80 percent cheaper than the going-forward costs for coal, absent a few edge cases. Typically, the least economic plants have low capacity factors that result in very high fixed marginal costs per MWh or very high fuel costs.

For more than three-quarters of U.S. coal capacity, the all-in cost per MWh of the cheapest renewable option is at least a third cheaper than the going-forward costs for the coal it would replace (see Figure 8).

The substantial cost savings from replacing coal with renewables indicates the potential to invest in additional resources that provide complementary services like flexibility and transmission, without raising costs. Policymakers should consider a portfolio of clean resources that together provides adequate value and any needed reliability services. These resources could include storage, regional or interregional transmission upgrades, demand-side resources, and complementary portfolios of wind and solar.

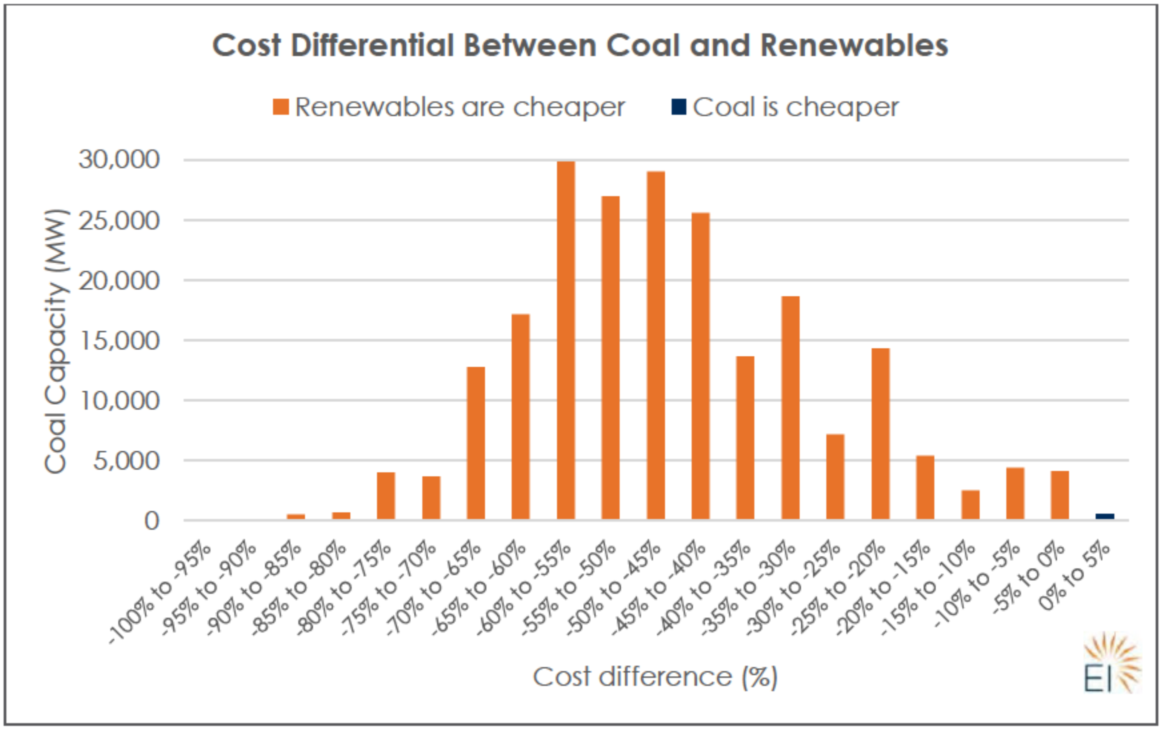

Figure 8. Aggregated plant capacity shown as percent difference between renewables LCOE and coal going-forward cost. The orange bars indicate capacity where renewables are cheaper than coal and coal is deemed "uneconomic." The one blue bar indicates the sole plant that is still cheaper to operate than replace with renewables.

Local replacement of coal

Local solar and wind

For 199 of the 210 plants studied we find that local solar replacement is more economic than coal, based on energy generation alone, and for 75 plants it is the cheapest option entirely. Local wind is also a viable option for many plants, with 104 plants having cost-effective local wind resources and 13 having local wind as the cheapest option. For 98 plants, both local wind and local solar were cheaper than coal. While we did not study any combinations of the two, this result indicates that a portfolio that includes both local wind and local solar would likely be a viable option with additional reliability value near many plants.

In these local replacement scenarios, we looked at replacing all the annual electricity generated by a given coal plant with either local wind or local solar within 45 km of the plant. This allowed us to assume lower interconnection costs[xi] (a significant barrier for new projects)[21] while taking advantage of the IRA's energy community tax credit bonus. In nearly all cases we studied, the reduced interconnection costs and added tax credit compensates for potentially lower resource quality when restricting site selection in areas close to the plant. We find particularly good resource quality in the local solar scenario, where 191 plants have sufficient sites nearby such that their generation can be replaced within 20 km.

Solar plus storage stepping in at North Valmy

In Nevada, NV Energy has already realized the cost and community benefits of using solar plus storage in place of the 567 MW North Valmy Generating Station, near Winnemucca. Two new solar plus storage facilities located within the same county will replace this plant when they are completed by 2025. The two replacement projects will provide 250 MW solar capacity plus 200 MW of storage, and 350 MW of solar plus 280 MW of storage. These projects will also create several hundred construction jobs, and the storage will help shift the solar generation to the times of day it is most needed, serving the reliability needs of the area. This is consistent with our analysis, which finds that it would be cheaper to use solar plus storage up to the full plant's capacity than to continue to run the coal plant. Plants across the country can now follow Valmy's example and effectively decarbonize with solar plus storage.

Local replacement offers three other benefits. First, local replacement can help preserve livelihoods and tax revenue for surrounding communities through the energy transition.[xii] Second, local resource replacement falls into the category of projects that can qualify for loans via the DOE's

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[xi] In our modeling, we use ReEDS spur line costs as a proxy for interconnection costs of regional renewables. For local renewables, we assume no interconnection costs because the point of interconnection already exists at the coal plant. This is a simplification—each site will be different and will require an interconnection study or transmission plan to ascertain the interconnection costs.

[xii] New renewable energy installations are only one piece of the puzzle when it comes to community transition as they typically do not provide as many jobs or as much tax revenue as a coal plant. While local energy replacement can contribute, further community re-development and economic diversification is needed, as discussed further in the policy recommendations section.

EIR program, as the projects would be a direct reinvestment in energy infrastructure. Our analysis shows investment in local solar resources could drive $589 billion in capital investment to energy communities across the country (see Figure 9).

Third, siting renewables in proximity to plants creates the possibility that these new resources could use the existing plant's grid interconnection. Recent analysis of PJM's interconnection process shows that the median interconnection cost from 2020 to 2022 grew ten-fold over the costs from 2017 to 2019, largely due to transmission network upgrade costs.[22] While we considered reduced interconnection costs for local resources, the advantage of local replacement could be even more considerable as the cost of the line is only a part of the problem. For clean energy projects across the country, long interconnection wait times are also a major hurdle to overcome.

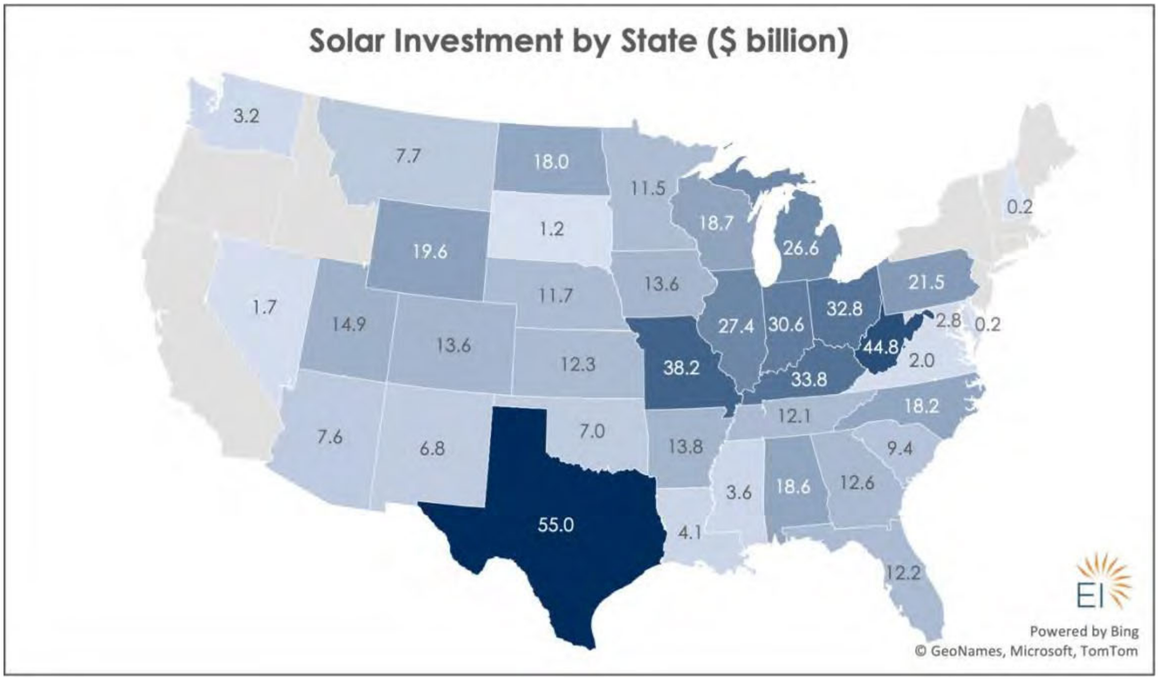

Figure 9. The solar capacity needed to provide enough energy to make up for coal generation across the country would drive hundreds of billions in investment. States with no investment number had no plants in our data set.

Local solar plus storage

We followed up on our local solar scenario by looking at a solar plus storage replacement option for each plant that includes local solar energy plus four-hour batteries to provide additional capacity value and higher market profitability in some cases. We find that the savings available from switching from coal generation to local solar generation can finance 137 GW of four-hour battery capacity at a price of $330/kWh across the coal fleet.

For more than a third of the coal capacity studied, we find that in addition to energy generation replacement with local solar, 80 percent or more of the plant's capacity can be replaced with four-hour batteries at a combined levelized cost that is still less than the going forward cost of the plant. For the remaining plants, the percentage of capacity that can be economically replaced is still quite significant: We find that savings from renewable generation could fund storage at more than 50 percent plant capacity at 136 plants.

Renewable options cheaper than expensive upgrades at Mitchell plant

In 2021, American Electric Power determined it would likely be more cost-effective to retire West Virginia's Mitchell Power Plant than pay for expensive pollution control upgrades required by the U.S. Environmental Protection Agency (EPA). However, the West Virginia Public Service Commission (PSC) ruled that the utility had to keep the plant open, and that WV ratepayers must pay for the upgrades. At the same time, in Kentucky and Virginia, who were also receiving power from the plant declined to make their state's customers pay, leaving West Virginians to shoulder a $448 million price tag. Our analysis shows taking advantage of regional wind resources would be 48 percent cheaper than continuing to run this polluting plant. Replacement with local solar and battery storage would be 50 percent cheaper and would provide the reliability the PSC seeks while saving ratepayers hundreds of dollars every year.

This local solar plus storage arrangement has at least three advantages:

First, solar plus storage provides resources with a significant capacity and ancillary service value at the same place on the power grid, addressing in part possible reliability concerns that may be associated with coal plant retirement.

Second, the new storage ITC means batteries do not need to be co-located with renewables to take advantage of the tax credit. This means that while local renewables may need to be sited a short distance from the plant, storage can be placed directly at the coal plant site and use existing electrical infrastructure to act as a central collection site for renewables. This arrangement also bolsters economic development opportunities in coal communities.

Third, combining solar and storage empowers a gradual coal phase-out, benefiting communities and grid reliability. Electricity generated from coal can be reduced, while keeping the coal boiler and generator available for emergencies. If needed, the generator can eventually be transformed into a piece of grid regulation hardware requiring no boiler, and batteries can store and release renewable energy to make the whole system available at times of highest grid demand. Renewable energy can be a part of an economic diversification package that may include other re-purposing of the site, such as a plant in Michigan that was re-developed into an insurance company's headquarters.[23]

The reliability implications of coal plant retirement should be evaluated for each specific plant. A one-to-one replacement is often not necessary given the capabilities of the remaining power plant fleet. For example, the battery capacity necessary to take over the reliability burden of any given coal plant is varied, depending on the role of the plant and broader resource mix, and it is not needed at all in many cases. Wind and solar (especially in a complementary combination) already tend to provide a measure of capacity value to the regional grid. Other assets like faster, more flexible gas units or behind-the-meter resources may already be carrying more of the regional reliability burden, and transmission expansion can help reduce the need for dispatchable generation for resource adequacy as well. Therefore, coal capacity is not always necessary for reliability depending on the resource adequacy in each region as determined by the balancing authority.[24]

Figure 10 shows the percentage of battery capacity at each plant that can be funded by coal replacement with local solar, providing a range of options for combining renewables with storage.

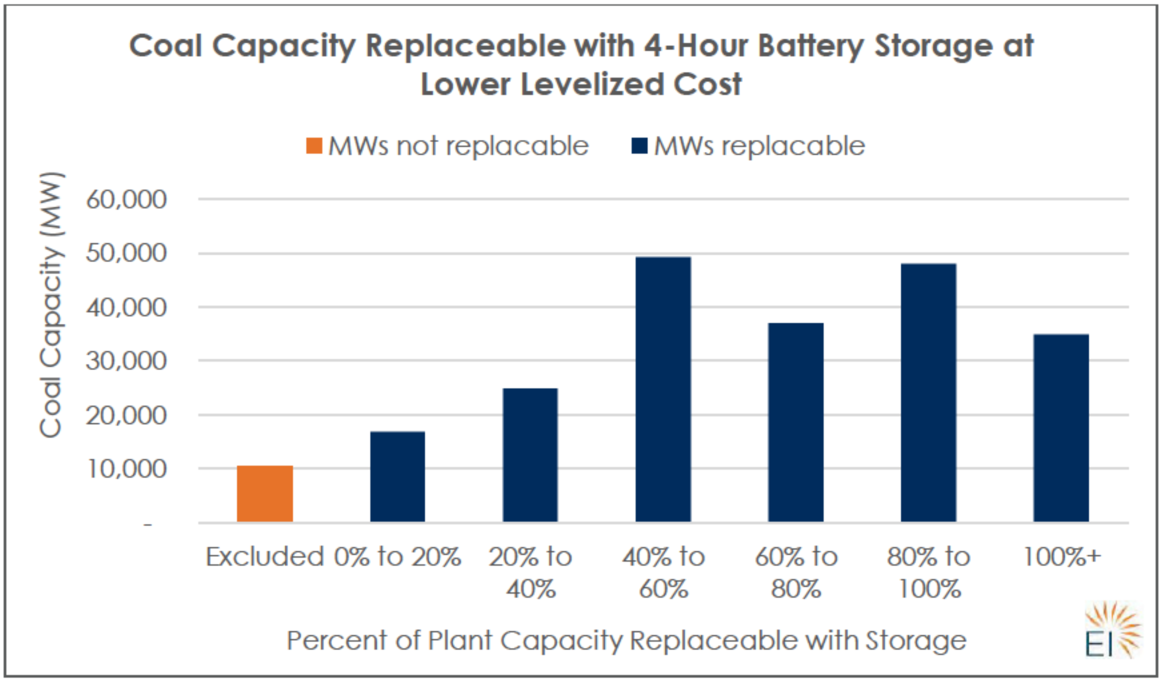

Figure 10. Coal plant capacity (in MW) by the percentage that can be replaced using only coal crossover savings. "Excluded" indicates plants for which local solar generation was available but was not cheaper than coal.

The economics of battery replacement for capacity are highly dependent on battery costs. For the analysis above, we used $330/kWh as the cost of storage, which is the 2021 cost for storage in the NREL 2022 ATB.[25] Our cost accounted for the new standalone storage ITC and energy community tax credit. To study the sensitivity of these findings to battery prices, we evaluated the potential for capacity replacement across prices ranging from $100/kWh to $400/kWh (see Figure 10).

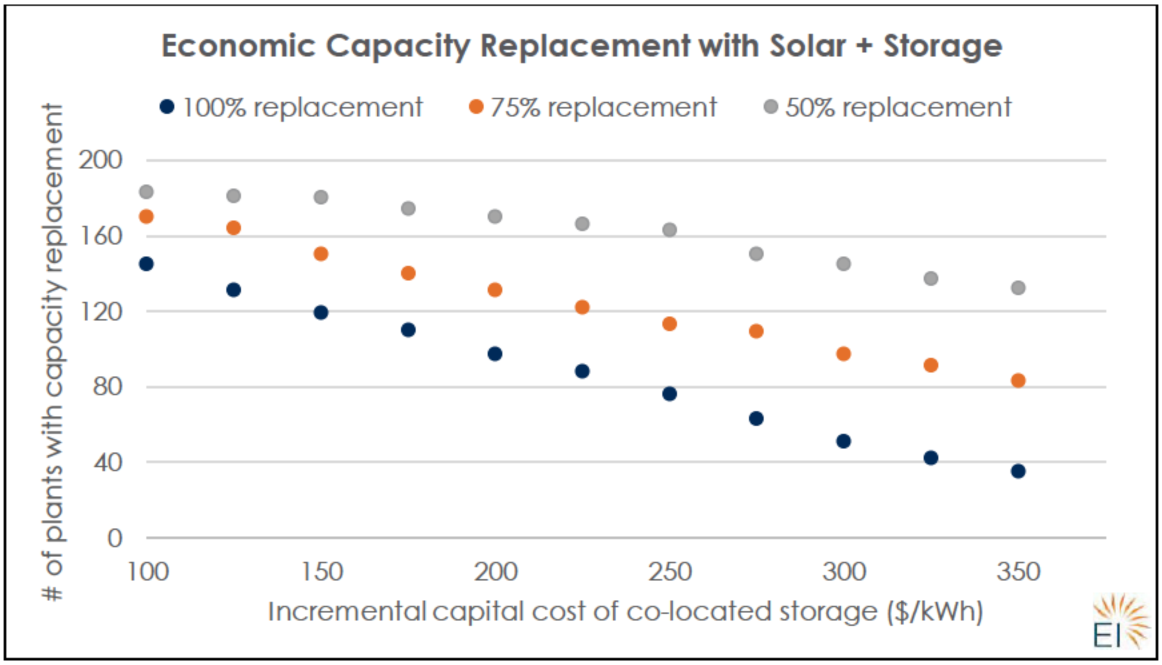

Figure 11. Economic battery capacity relative to battery price by percent capacity that can be replaced at each plant.

Utilizing additional financing to fund local resources: Ameren's Rush Island Plant

It is important to note, however, that fuel savings are not the only source of savings that could help finance replacement batteries in a coal-to-local renewables swap.

For example, Ameren's Rush Island power plant in Missouri is not a strong candidate for financing batteries solely with savings from switching to local renewables. Yet by also accounting for needed upgrades, the plant's remaining balance, and reliability concerns, the case for financing batteries for reliability value becomes stronger.

Ameren was planning to retire the 1,195 MW coal plant in September 2022 partially due to the expense of adding court-ordered selective catalytic reduction (SCR) to address air pollution noncompliance, with a price tag of $310 million[xiii] to $1 billion.[26] Unfortunately, because early retirement could cause severe voltage stability problems leading to cascading power outages, the Midcontinent Independent System Operator (MISO) sought to keep the plant online and received Federal Energy Regulatory Commission (FERC) approval for a 12-month system support resource agreement to be renewed annually.[xiv] According to the grid operator, potential renewable energy additions or possible demand-response programs wouldn't adequately address the location-specific voltage problem. However, due to the geographic nature of the potential voltage instability, local renewables coupled with batteries could go a long way toward mitigating this concern without waiting for the transmission upgrades MISO deemed necessary.

Our initial analysis finds that switching to renewables could generate savings to pay for replacing replacement of only 4 percent of the plant's capacity with batteries. However, the IRA now creates new possibilities. Because Ameren faces capital expenditures in the $300 million to $1 billion range, and already holds an estimated $600 million for the plant in its rate-base (interest on which is paid by its customers at standard utility rate of return), existing state public utility commission securitization authority could be used to refinance this obligation in combination with the EIR program, generating much greater customer savings.[xv] Investing these savings in four-hour battery storage could match 85 to 165 percent of the plant's capacity. Furthermore, batteries would only be necessary if the local renewables on their own were not sufficient to provide voltage support or if the proposed transmission solutions proved too slow or expensive.[xvi]

New IRA financing and tax credits make replacing coal plants with a combination of local wind and solar power supported by batteries an attractive option for most coal plants in the U.S. Such replacement can be done with a minimum of disruption to the grid while keeping jobs in affected communities—not to mention the great improvements to public health from reduced pollution.

POLICY RECOMMENDATIONS

Our analysis makes it clear the comprehensive the IRA tax incentives have created a favorable policy environment for the coal-to-clean transition. However, the transition can be made even more cost-effective if utilities harness the IRA's loan and grant programs and use best practices to assess cost-saving replacement options.

[xiii] Assuming $250/kW all-in costs. See https://www.powermag.com/estimating-scr-installation-costs/.
[xiv] MISO identified four transmission upgrades that are needed to maintain voltage on the grid, with the last one expected online by June 2025, according to the grid operator. See https://www.utilitydive.com/news/ameren-missouri-coal-rush-island-miso-ferc/630226/.
[xv] The interest rate on the securitized loans or government-backed loans through EIR are assumed to be 2.95 percent, or the average of the 20-treasury yield across the last 10 years plus 0.375 percent. Missouri law already allows for coal plant securitization.
[xvi] While MISO investigated replacement of the plant with renewable energy, it does not appear that MISO considered renewables in geographic proximity to the plant.

Planners and policymakers should make sure they are not caught unprepared by a wave of retirements, and that replacement renewables and complementary flexible resources can be deployed in a timely manner. Advocates and policymakers interested in capturing the economic and public policy benefits of shifting away from coal can take several actions to ensure that power plant operators take advantage of the moment by requiring utilities to account for IRA incentives and funding programs in planning and procurement. Finally, our analysis suggests that IRA provisions designed to encourage a just transition for coal communities are well positioned to spur new investment in generation and grid balancing resources in the immediate vicinity of existing plants, but experience has shown that a just transition will only happen with the careful attention of legislators and regulators alongside local communities.

Reliability assessment keeping expensive Indian River plant online

Delaware's only remaining coal plant, Indian River Generating Station, was planned for retirement by June 2022—until the grid operator, PJM, requested it remain open until 2026. PJM had determined that transmission upgrades would be needed to stabilize the grid before the plant could be taken offline. The plant, which only has one remaining unit, is historically the worst polluter in Delaware and also the eighth most expensive plant we analyzed due to low capacity factor and high estimated fuel costs. Local replacement of this plant could assuage reliability concerns by providing generation and capacity needs at the same location on the grid. Our local analysis finds that 246 MW of storage could be funded via savings. At over 50 percent of the plant's capacity, this is a good candidate for re-assessment of reliability needs.

Preparing the way for coal transition

Improving interconnection and transmission processes

The Rush Island Power Station example discussed above is not unique and blocking retirement of uneconomic plants due to broader system stability concerns and transmission requirements harms customers. To move forward while maintaining reliability, independent system operators (ISOs) and regional transmission organizations (RTOs) should proactively study solutions that can enable plant retirements. The alternative—overriding utility retirement plans and requiring FERC approval for expensive stopgap payments to keep high-cost plants running—is not good for utilities or their customers.

Our analysis shows that post-IRA, almost every coal plant has reached its economic tipping point. As pollution standards and clean energy policies continue to worsen coal plant economics, ISO/RTOs will increasingly encounter situations where innovative resource portfolios will be needed to economically and reliably replace coal plants, including transmission. As neutral arbiters of just and reasonable rates, system operators must be ready to enable cheaper electricity and public policy goals by allowing utilities to retire uneconomic plants. Proactive transmission planning and deployment, alongside improvements to interconnection processes are both crucial to prepare for uneconomic plant replacement.

Absent regulators stepping in, retiring a plant is much easier than building a new renewable project. Price signals may induce coal retirements before new renewable projects can be approved and built to take their place. The growing interconnection queue backlog is of particular concern here. As of 2022, the two largest power markets in the U.S., MISO and PJM, had about three times more renewables capacity waiting in the queue than they had existing coal capacity.

For PJM, this backlog was deemed insurmountable. While PJM works through its existing interconnection requests, it will not review new requests until early 2026. It is clear that additional measures to improve the interconnection process, including better regional transmission planning, are needed to avoid similarly extreme measures in the future.[27] FERC is currently considering interconnection policy changes, but state public utility commissions can also help by examining their state's queue and assessing whether proactive transmission buildout could connect cost-effective clean energy. In states outside an ISO/RTO, states hold sole responsibility for proactive transmission and planning process reform to reduce wait times and hasten the pace of in-state clean energy investment.

Building local: accelerating deployment while maintaining reliability

Action from FERC and other policymakers on interconnection reform and transmission buildout cannot come too soon. A recent brief from Lawrence Berkeley National Lab (LBNL) analyzing interconnection costs in the PJM region finds that, alongside the tremendous lengthening of the interconnection queue, interconnection costs have increased substantially in recent years.[28] The main driver behind these increases has been broader network upgrade costs, reflecting system changes due to the influx of renewables and the fact that optimal renewable sites are often far from the coal they might replace.

There is no doubt that variable renewable resources are fundamentally different from dispatchable fossil generators, but variability does not imply unreliability. Studies are clear: A coal-free U.S. electricity system can be dependable.[29] Yet renewables do require a different resource adequacy framework, which makes resource diversity, energy sufficiency, regional and interregional transmission, and demand response more important. As system operators design new resource adequacy metrics, regulators should support them by defining minimum resource adequacy requirements and soliciting cost information.[30]

In a high-renewables environment, interregional electricity transfer can help manage local weather variation, providing higher reliability at lower cost. RTOs and regulators can enable interregional coordination by expanding planning areas or subsidizing transmission lines that provide for specific reliability needs. Finally, regulators and state legislatures can require resources that bolster reliability like energy storage has become a cost-effective way to integrate renewables, as this report shows. However, storage still lags in investment. A legislative storage mandate, like the one passed in California in 2013 can help accelerate storage deployment.[31]

Ultimately, building out the network to include and adapt to some of the best available renewable resources, evolving the bulk power system's resource adequacy framework, and improving inter-regional coordination supports a least-cost, reliable electricity system given the new IRA incentives. But, as is evidenced by the delays described above, all this takes time. Building local resources closer to or at the same site as coal plants could dramatically accelerate clean energy deployment while providing significant incremental reliability value.

Prior to the IRA, local replacement was not always economic on an annual generation cost basis relative to the cost of maintaining a coal plant. However, to support a just transition, the IRA includes additional incentives for building new clean resources near coal plants or "energy communities." Our analysis shows that local wind or local solar plus storage could create a cheaper electricity portfolio than nearly every plant, while delivering the same amount of electricity and providing significant reliability value. Even if a coal plant weren't completely shut down, it could work in tandem with cleaner, cheaper resources fed through the same point of interconnection to deliver cheaper, cleaner electricity without materially affecting the transmission system and system operations (it might even improve these). Utilities, ISO/RTOs, and state and federal regulators should move swiftly to develop standard templates that allow for coal plant hybridization or replacement with clean portfolios. These templates would have to be generically robust enough to satisfy system reliability and stability concerns under a variety of conditions to replace coal without a lengthy interconnection process.[xvii]

Proactively pursuing transition

Re-evaluation of integrated resource plans and improving competitive procurement

While measures to proactively plan for and better accommodate new renewable projects are necessary to capture the huge economic benefits of transitioning expensive coal plants to cheaper renewables, they are not sufficient. Utility integrated resource plans routinely overestimate new renewable costs, and the IRA programs will likely make these overestimations even higher. Any

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[xvii] There may be concerns about undermining competition if some resources are allowed to skip ahead of the line, but presumably standard templates will involve costlier investments than what might be proscribed in a more specific interconnection study. In any case, it makes sense to recognize that providing replacement resources at or near an existing resource is easier and simpler for the network, and the benefits of just transition and accelerated deployment should be balanced against competition concerns.

investment plan or market-based solicitation for renewable contracts completed before August 2022 is now out of date. Regulators can expect independent power producers to offer lower bids for just about any clean energy technology. Under their authority to set just and reasonable rates, PUCs should insist that utilities redo integrated resource plans and resource solicitations, despite the procedural complexity. For example, advocates have already submitted evidence to the North Carolina Utility Commission that such a re-examination would be prudent for Duke Energy's Integrated Resource Plan and Carbon Plan.[32]

In addition to cost updates, integrated resource plans should account for the benefits of location-based procurement to replace coal generation. In New Mexico, the Energy Transition Act required the Public Service Company of New Mexico to site some of the replacement resources for the San Juan Generating Station in the nearby school district to replace lost tax revenue.[33] Because of location-specific tax credit bonuses, traditional regulatory requirements to minimize consumer costs now require an examination of local investment in replacement wind, solar, and battery resources.

FERC and NERC should work with the ISO/RTOs to create standardized approaches to gradual replacement with local resources and eventual development of reliable resource portfolios that include renewables, transmission, and emerging technologies like power electronics and synchronous condensers.

In addition to accurately assessing renewables during planning processes, enabling competitive procurement is crucial to getting steel in the ground. Even before the IRA, unsubsidized renewables were the cheapest new resource in most of the country. However, regulators can have difficulty discerning the true cost of clean energy or comparing variable clean resources with dispatchable fossil power providing different services. Such assessments generally depend on limited utility information.

All-source procurement is a way around this—it is a well-established but underutilized process that requires the utility to provide assessments of resource need, then bid these services to the market. For example, Xcel Energy Colorado achieved record-low wind, solar, and storage prices that shocked the electricity world with an all-source procurement in 2018, avoiding costly investments in gas and accelerating coal retirement.[34] PUCs should establish all-source procurement rules that link these solicitations as inputs to integrated resource planning processes that ultimately result in resource procurement—a key part of the Colorado planning process.[35] These solicitations also provide the opportunity to assess and define needed system reliability attributes after coal plants retire and allow supply-side, demand-side, transmission expansion, and regional market resources all compete to fill that need.[36]

Utilizing IRA funding and financing programs

Our comparison of the going-forward costs of existing coal plants with regional or local renewables doesn't capture all the economic advantages of such a transition. The IRA also includes measures that facilitate savings from lower cost financing.

First, the IRA created a $9.7 billion fund for rural electric cooperatives to reduce GHG emissions via a myriad of methods. With cooperative assets highly tied up in coal and without the same access to capital as investor-owned utilities, the transition to cheaper clean resources can be particularly challenging. To take advantage of these funds as soon as possible, co-ops should develop clear plans that use new clean energy and coal generation replacement to achieve deep GHG emissions reductions, in accordance with the IRA's statutory language.[37] For their part, states should provide resources to support the planning and application processes. With nearly 18 GW of plants in this analysis majority-owned by cooperatives, this program, if used to its greatest potential, could spur billions in rural economic development.

In addition to rural cooperative funding, the IRA provides substantial debt refinancing potential, when paired with reinvestment in new clean energy infrastructure. While we find all but one plant are uneconomic when compared to replacement with new wind and solar, many plants have large debt burdens that hamper the customer savings available from clean energy replacement. Some states have explicitly allowed utilities to refinance these remaining balances via securitization, but now all power plant owners have access to flexible low-cost capital to finance new clean energy projects reusing coal-

Cleaning up coal ash at the G G Allen Steam Plant

In 2014, the now-retired Dan River Power Station leaked 39,000 tons of coal ash into the Dan River—leaving residents without drinking water for years and requiring a $3 million clean-up. It also kicked off an investigation of Duke Energy in North Carolina that found all 14 coal plants in the state were leaking coal ash. G G Allen has the largest amount of coal ash on site out of all the plants with 19 million tons of that need to be removed. In addition to this high pollution impact, it is also the second most expensive coal plant to run in the U.S. according to our analysis. But it needn't be this way. North Carolinians can have clean air and water with cheaper clean energy. All four renewable scenarios in our analysis were cheaper than running the G G Allen plant. In addition to clean energy replacement, the use of a DOE loan guarantee could save ratepayers even more by using low-cost financing for replacement infrastructure including the coal ash remediation.

plant infrastructure via the DOE's new loan program.[38] PUCs should require utilities to update prior investment and coal retirement plans to reflect the low-cost capital now available for reinvestment in communities.

Particularly for independent power producers, which own 23 percent of the coal capacity we studied, these DOE loans will be significantly cheaper than those without government backing. The loan guarantee must be used to reduce GHG emissions and reinvest in that same community.[39] Funds can be used for a wide range of applications including partial or full coal replacement with renewable resources, transmission and storage, and even remediation of former fossil fuel sites, improving environmental conditions and serving as another source of job creation for the local community. Given the flexibility of the program, this is far from an exhaustive list.To smooth community transition, loans need not require immediate plant retirement, but instead could support projects that gradually reduce coal while increasing renewable generation and diversifying the community's economy.[40] The local renewable replacement plus storage scenario we study fits this approach.

Just transition in Colorado

In 2019, the Colorado legislature passed a bill creating the first Office of Just Transition (OJT), and just in time. With six coal mines and seven coal-fired power plants still operating, small communities, particularly in Western Colorado, risked near-total economic collapse. Since the legislation passed, the OJT created a Just Transition Action Plan to support economic diversification and job retraining. The town of Nucla illustrates how this plan can work. When their coal plant shut down three years ahead of schedule, it was the largest employer. The plant also provided nearly half the tax revenue that supported the whole region—including the fire department and school district. Residents were rightfully concerned, but Nucla has worked with OJT to transition their economy to focus on tourism and small businesses. Nucla still has a way to go and more funding is needed, but Nucla shows how pre-emptive planning can help ease the sting of coal closures. Now, newly appropriated OJT funds will continue to help Nucla restructure while preparing other Colorado coal communities.

Just transition for affected communities

State PUCs, legislatures, and state energy offices all have a role to play ensuring a just transition for coal communities. New IRA funding mechanisms mean traditional, least-cost utility planning practices now require reinvestment in communities whose economic prosperity depends on coal plants and coal mining. Assessing and including reinvestment in these places is now essential to “least cost, best fit” resource planning.

Of course, the nuances of community needs are more complex than simple economics, and fully considering viable transition strategies in integrated resource plans is not possible unless state regulators and utilities seek input from affected communities at the beginning of the planning process. Seeking community input is not typically part of existing integrated resource planning processes, and it can be challenging for resource-constrained PUCs or utilities to incorporate new, innovative approaches to stakeholder engagement and ultimately community transition.[41]

State legislation should require PUCs and utilities to plan for community transition and assess the value of federal loan guarantees and tax credits for community transition, starting with outreach in an investigatory proceeding that provides access by holding commission forums in those communities. With this input, utility investment plans can better meet community economic needs, which can include tax revenue, workforce development, infrastructure investment, pollution clean-up, and community ownership models like community solar.

While the IRA has several reinvestment programs, energy communities cannot rely on clean energy alone to fully replace coal jobs and tax revenue. However, local clean energy can provide the opportunity for additional industrial development if new data centers or industrial facilities like synthetic fuel producers seek direct on-site access to low-cost clean energy. Proactive diversification of local economies is another path for success, which would benefit from state resources. The transition can even begin before the plant retires—gradual replacement and interconnection could ramp up in anticipation of the plant’s eventual retirement, growing jobs and reducing pollution along the way.

Legislators should consider creating and funding a just transition office, following Colorado’s example, to help coal communities develop transition plans. In addition to these legislative actions, PUCs can consider putting community transition funding into rates or creating ratepayer and shareholder cost sharing arrangements, similar to the arrangement made following closure of the coal plant in Colstrip, Montana.[42]

CONCLUSION

The economic case for replacing highly polluting and expensive coal-fired generation with clean energy is stronger than ever. Our new analysis, based on 2021 data, already surpasses our previous projection for 2025, finding that 99 percent of all U.S. coal plants are more expensive to run compared to new clean energy generation. Local replacement is more attractive than ever due to the IRA’s new incentive and funding programs. Including battery storage along with local renewable generation can be an economic way to bolster the reliability value that these renewable projects provide to the grid. Building new wind or solar before completely retiring existing coal can be a recipe for success, a paradigm supported by the DOE’s new loan authority. The near-complete crossover of coal economics versus renewables makes the imperative to transition clearer than ever before, but policymakers, utilities, consumers, and coal-dependent communities must recognize the benefits and seize this moment.

APPENDIX: DETAILED METHODOLOGY

Coal Costs

Our goal was to develop an accurate estimate of the going-forward cost of running U.S. coal plants using publicly available data from EIA, FERC, and EPA. In assembling a master list of U.S. coal plants, we restricted ourselves to plants running mostly coal (excluding wood waste and petroleum coke burning units) operated by utilities and independent power-producers (sectors 1 and 2, in EIA parlance), excluding plants used for combined heat and power, for which the economics are more complicated because these plants receive other revenues from providing heat.

As a matter of convenience, we limited ourselves to coal plants in the lower 48 states and excluded a few plants for various practical reasons like corrupted or unavailable data. The companion spreadsheet to this report lists these in detail. In any case, these cuts did not materially reduce the number of GWs of capacity we covered. Finally, we grouped boilers and generating units together at one location as single plants, while excluding boilers and generating units fueled mostly with natural gas. The final master list of 210 coal plants is available in the companion spreadsheet to this report.

The going-forward cost for each coal plant in our master list comprises three principal components

- The cost of fuel on a per MWh of coal generation basis.
- The operation and maintenance cost of each plant levelized over the total generation from each included boiler and generating unit.
- The average annual going-forward costs for capital investments needed to replace and upgrade part of the power plant levelized over the total generation from each included boiler and generating unit.

This Appendix reviews our methodology for each of these three elements in more detail.

Cost of Fuel

Our principal method for calculating fuel cost for any given coal plant comes from first computing its cost of energy inputs in dollars per million British Thermal Units ($/mmBTU). We need a heat rate in mmBTU/MWh to convert this input into a cost of delivered energy in $/MWh. The heat rate is a number particular to any given plant that varies according to any number of contextual factors (e.g., fuel-type, technology, age, outside temperature, capacity factor). As a matter of simple expediency, we use a heat rate for each power plant defined by the sum of BTUs from all nonnatural gas fuels burned at that plant in 2021 divided by all the net-generation from these fuels as defined in the first page of EIA Form 923. We used this to convert input fuel costs into output electricity fuel costs.

We then used EIA data on fuel contracts paid by the plant; listed on page 5, “Fuel Receipts and Costs,” of EIA Form 923. The EIA 923 spreadsheet lists fuel contracts with heat contents (mmBTU per fuel unit) and price paid in cents per mmBTU. From these contracts we can establish an mmBTU-weighted cost per mmBTU for coal, which we use as an input cost for that plant. Note that this does not include fuel processing costs that might be covered in values reported to FERC. Probably the most important example of fuel processing comes from plants that report burning so-called “refined coal” on one part of Form 923 while at the same time reporting direct purchases of other coal, e.g., bituminous coal, on another part of the form. This discrepancy is due to the fact that “refined coal” involves processing purchased coal (usually by spraying it with certain chemical agents) to reduce emissions from the smokestack. It is hard to know how much this extra processing costs on a per mmBTU basis, but we understand that the economic rationale for doing so is driven mostly by a tax credit. Historical trend analysis of some plants that burn “refined coal” shows that they sometimes choose to apply this processing and sometimes not reflecting, in our opinion, the likelihood that there is only a small impact on fuel costs to “refining” after netting out processing costs and tax credit income.

For plants that do not report input fuel costs to a regulator, however, other less plant-specific sources of information were required. In these cases, instead of specifically reported plant data, we used state-based data on the average cost of coal from EIA. To accurately reflect the diversity of coal types and relative mix of types that various plants consume, we used a combination of total plant coal consumption and state average coal costs from EIA as well as historical fuel consumption trends at the plant to estimate source coal type and marginal fuel costs. We used the following procedure:

Step 1: Extract the various mmBTU quantities of coal by type used by the boilers in each coal plant of interest from the 2021 EIA Form 923.

Step 2: Link each coal type with a state benchmark input fuel price in $/mmBTU. We establish that benchmark price by combining information on electric power sector coal prices by coal type and plant state from EIA’s Coal Data Browser with coal heat content (mmBTU/ton) by state and coal type, also from EIA’s Coal Data Browser (if heat content for a given coal type was unavailable for the 2021 reporting year, we used the most recent year).

Step 3: Tag “refined coal.” One type of coal that appears in boiler consumption figures but not price tables is “refined coal.” To price this type of consumption, we assigned each instance of “refined coal” to a coal sub-type. Depending on the plant, the source coal for “refined coal” might be bituminous, sub-bituminous, or lignite. With some painstaking work, we were able to infer from other nearby plants and historical fuel consumption trends at the plant which coal type was being refined with high confidence.

Step 4: Combine coal types to get a plant fuel cost. We combined price and consumption levels at each plant to get a weighted fuel input cost in \$/mmBTU. We then converted this to \$/MWh using the heat rate—just like the plants that report their input fuel costs.

Operation and Maintenance Costs

We used plant-by-plant operation and maintenance estimates obtained from the Electricity Market Module (EMM) in EIA's North American Energy Modeling Systems (NEMS). For some plants, no NEMS value for operation and maintenance was available and we used a national average value.

Going forward capital costs — National Energy Modeling System (NEMS)

The third element in our overall coal going-forward cost estimate is the going-forward capital cost. For this element we used a fairly simple method. We started by taking the average age (weighted by generator capacity) of a given coal power plant and compared it to the EIA NEMS table found in Figure 12. From this NEMS table and the average age of the plant, we obtained a per kW-year going-forward cost, which we multiplied by the overall capacity of the plant. We then divided by the total net MWh output from the plant (defined by the included set of generators) as reported on EIA Form 923. This includes any natural gas-fueled generation and results in a \$/MWh, which then factors into the complete coal going-forward cost.

Age	Annual Capital Investment Requirement (\$/kW-yr)
0 - 10 years	\$ 17.16
10 - 20 years	\$ 18.42
20 - 30 years	\$ 19.68
30 - 40 years	\$ 20.94
40 - 50 years	\$ 22.20
50 - 60 years	\$ 23.46
60 - 70 years	\$ 24.72
70 - 80 years	\$ 25.98

Figure 12. NEMS estimates of going forward capital costs by age of plant.

Renewables Costs

Identifying Renewable Energy Sites

We use NREL's ReEDS model that provides high spatial resolution solar and wind potential datasets in the U.S. The solar and wind potential numbers in ReEDS are, in turn, taken from the Renewable Energy Potential (ReV) model, which assesses the wind and solar energy potential at 11.2 km x 11.2 km spatial resolution after applying comprehensive exclusion criteria, including land cover, elevation, slope, environmentally sensitive areas, local siting regulations, etc. Across the continental U.S., ReV and ReEDS identify nearly 50,000 individual solar sites totaling a potential of 96,000 GW, and around 50,000 individual wind sites totaling a potential of 6,600 GW. The ReEDS model also provides annual capacity factors at each of these sites, which are estimated using the wind speed, solar irradiance, temperature, and other weather parameters from the Wind

Integration National Dataset (WIND) and National Solar Radiation Database (NSRDB). More information on this can be found in ReEDS documentation.

Technology Costs

We run the ReEDS model using technology costs from ATB 2022 and IRA incentives and estimate the wind and solar LCOE at each of the 50,000 sites. ReEDS uses a comprehensive list of parameters to estimate a site-specific LCOE including capital costs, fixed operation and maintenance costs, equity costs, interest rates, construction costs differentiated by location across the U.S., construction period, ITC and PTC incentives per IRA, tax equity haircuts, depreciation, and taxes (see Figure 13). Additional details on LCOE estimation could be found in ReEDS documentation.

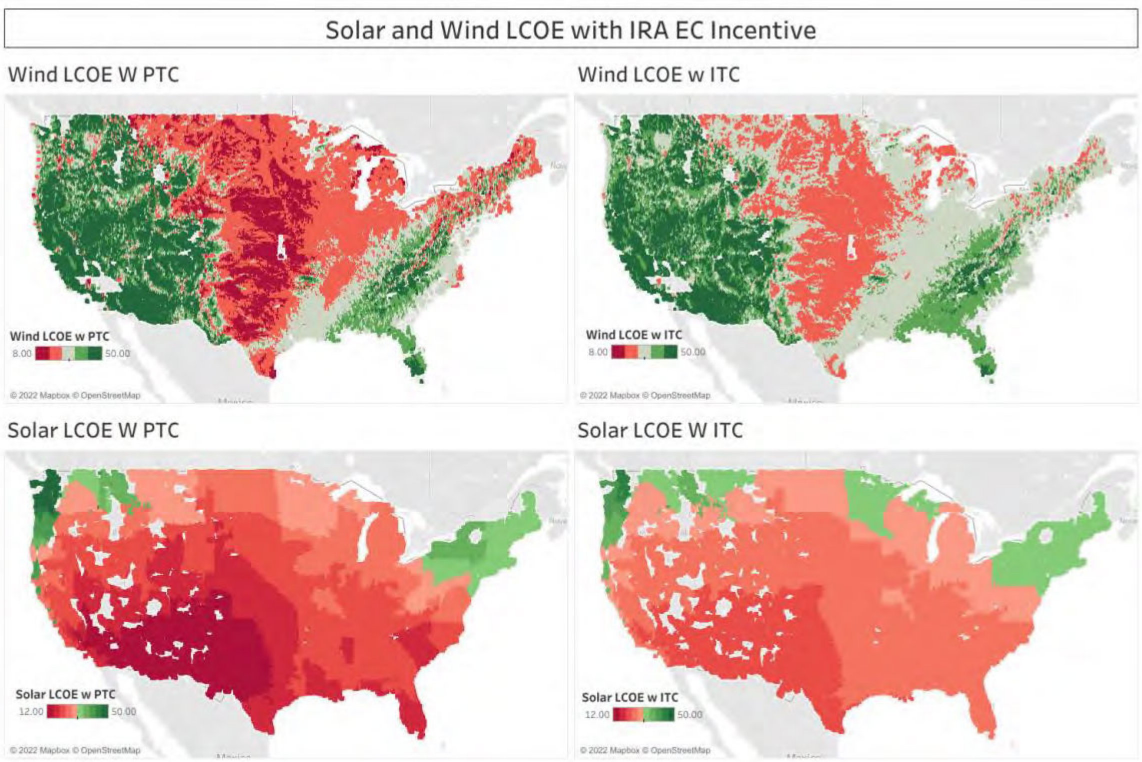

Figure 13. Wind and Solar LCOE including IRA incentives (including energy community) at each of the individual 50,000 sites across the U.S.

Assessing Hyperlocal Potential and LCOEs

The objective of this exercise is to assess the physically closest (hyperlocal) solar or wind resources that could replace the generation from each coal power plant in the country. We start with the location (latitude and longitude) of each of the 210 coal plants in the US. We then create concentric circles around each coal plant with radiuses starting from 5 km up to 45 km in increments of 5 km. Within each of these concentric circles, we identify the solar and wind sites that fall within that circle and estimate the site-level capacity and annual generation potential for solar and wind resources separately, using the high-resolution solar and wind datasets available from ReEDS, as described earlier. We then estimate the minimum circle radius ("hyperlocal circle") needed to replace the annual generation from each coal power plant with solar or wind resources. Within each hyperlocal circle, we assume that the solar and wind projects get the Energy Community Tax Credit per IRA and will not incur any interconnection costs since they could continue using the coal plant interconnection. We weight the site-level LCOEs within each hyperlocal circle by the site-level capacity potential to arrive at a weighted average hyperlocal LCOE to replace the generation from each coal power plant.

We find that annual generation at almost all coal power plants can be cost-effectively replaced by solar resources within a 20 km radius. The minimum radius for wind is much higher.

Regional LCOEs

In addition to the hyperlocal LCOEs, we also estimate the regional LCOEs in the regions where coal plants are located. The ReEDS model divides the contiguous U.S. into 134 regions which are generally aligned with the utility territories (see Figure 14). These regions never cross state boundaries

The rationale for estimating the regional LCOEs in addition to the hyperlocal LCOEs is that the higher-quality resources might not be available in the near vicinity of the coal plants but slightly farther away, and so from the perspective of the developer, it might make sense to move further from the coal plants to access the higher quality resource. This is more important for wind as wind speeds can vary significantly over short distances. As compared to wind, solar is more energy dense, as we can get almost 10 times the capacity of solar in the same amount of land as wind.

The methodology used for estimating regional LCOEs is very similar to that of hyperlocal LCOEs. For each coal plant, we sort the wind and solar sites available in that region (i.e., ReEDS balancing area) by LCOE and choose the best sites to replace the coal generation. For selected sites within each region, we capacity-weight the site-level LCOEs to estimate the weighted average regional LCOE. For the regional LCOE, we do not account for the Energy Community tax credit available in IRA. We also add the interconnection costs to the LCOEs as we assume that these sites may not be able to access the existing coal power plant interconnection.

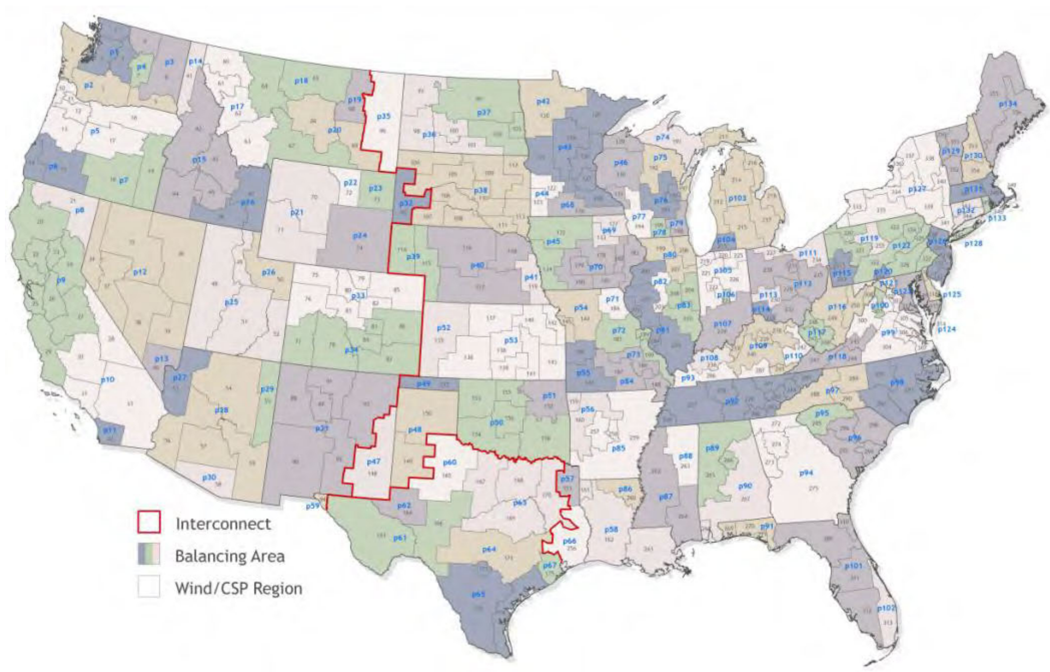

Figure 14. ReEDS balancing areas, used for our regional analysis and roughly corresponding to utility service territories, are highlighted by the different colors in this map. Source: National Renewable Energy Laboratory.

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BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c) Emergency Order: Midcontinent Independent System Operator and Northern Indiana Public Service Company LLC	)))))	Order No. 202-26-19
Federal Power Act Section 202(c) Emergency Order: Midcontinent Independent System Operator and CenterPoint Energy Indiana South	))))	Order No. 202-26-20

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

Exhibit 52
Department Export Authorization EA-365-C (Oct. 21, 2025)

United States
Department of Energy

Grid Deployment Office

Research Power Corporation
(formerly known as Centre Lane Trading Ltd.)
GDO Docket No. EA-365-C

Order Authorizing Electricity Exports to Canada

Order No. EA-365-C

October 21, 2025

Research Power Corporation
(formerly known as Centre Lane Trading Ltd.)
Order No. EA-365-C
Authorizing Electricity Exports to Canada

I. BACKGROUND

The Department of Energy (DOE or Department) regulates electricity exports from the United States to a foreign country in accordance with Federal Power Act (FPA) § 202(e) (16 U.S.C. § 824a(e)) and regulations thereunder (10 C.F.R. §§ 205.300 *et seq.*). This authority was transferred to DOE under §§ 301(b) and 402(f) of the DOE Organization Act (42 U.S.C. §§ 7151(b) and 7172(f)). On April 10, 2023, this authority was delegated to the DOE's Grid Deployment Office (GDO) by Redelegation Order No. S3-DEL-GD1-2023.

An entity that seeks to export electricity must obtain an order from DOE authorizing it to do so. Under FPA § 202(e), DOE "shall issue such order upon application unless, after opportunity for hearing, it finds that the proposed transmission would impair the sufficiency of electric supply within the United States or would impede or tend to impede the coordination in the public interest of facilities subject to the jurisdiction of [DOE]." 16 U.S.C. § 824a(e). DOE has discretion to condition the order as necessary or appropriate; the Department "may by its order grant such application in whole or in part, with such modifications and upon such terms and conditions as [DOE] may find necessary or appropriate, and may from time to time, after opportunity for hearing and for good cause shown, make such supplemental orders in the premises as it may find necessary or appropriate." *Id*.

A. Application for Export Authorization

Research Power Corporation (the Applicant) is a power marketer seeking renewal of its authorization to export electric energy to Canada, which was originally granted in Order No. EA-365-A on June 29, 2015, and subsequently renewed (EA-365-B) on April 29, 2020. On December 26, 2024, Centre Lane filed an application with DOE (Application or App.) requesting renewal of its export authority for a five-year term. App. at 1. On July 7, 2025, the Applicant notified DOE of its corporate name change from Centre Lane Trading Ltd. to Research Power Corporation.

According to the Application, Research Power Corporation (formerly known as Centre Lane Trading Ltd.) "is a Canadian Corporation with its principal place of business in Toronto, Ontario" that is "organized under the *Business Corporations Act* of the Province of Ontario, Canada." *Id*. The Applicant states that it "does not own, operate or control any generation or transmission facilities in any region, nor is it affiliated with any entity that owns, operates or controls generation or transmission facilities, and is not affiliated with any franchised public utility." *Id* at 1-2. The applicant further represents that it is a "[Federal Energy Regulatory Commission]-authorized power marketer engaging in the purchase and sale of physical and/or virtual energy in the Day-ahead and Real-time Markets of various Independent System Operators and Regional Transmission Organizations." App at 2.

Research Power Corporation represents that it "has no electric power supply system on which the proposed exports could have a reliability, fuel use system or stability impact." App. at 3. The Applicant states that it "has no obligation to serve native load usually associated with a franchised service area, and, thus, the exports proposed by [Research Power Corporation] will not impair its ability to meet current and prospective power supply obligations." *Id.* The Applicant further affirms that it "will purchase power to be exported from a variety of sources such as power marketers, independent power producers, or U.S. electric utilities and federal power marketing entities as those terms are defined in Sections 3(22) and 3(19) of the FPA" and that "such power is surplus to the system of the generator and, therefore, the electric power that [Research Power Corporation] will export on either a firm or interruptible basis will not impair the sufficiency of the electric power supply within the U.S." *Id*.

The applicant states that it "will make all necessary commercial arrangements and will obtain any and all other regulatory approvals required in order to schedule and deliver power exports." *Id*. The Applicant further states that it will "schedule its transactions with the appropriate balancing authority areas in compliance with the reliability criteria standards and guidelines established by the North American Electric Reliability Corporation[.]" *Id*. Research Power Corporation also attests to not exceed the export limits for the facilities, or otherwise cause a violation of the terms and conditions set forth in the export authorizations for each. App at 4.

B. Procedural History

On December 26, 2024, Centre Lane filed a renewal application with DOE for export authority for a five-year term. *Id* at 1. On June 16, 2025, DOE published notice of Centre Lane's Application in the Federal Register (90 Fed. Reg. 25252) and asked for any interested parties to submit comments on the Application by July 16, 2025. On July 7, 2025, DOE received notice of Centre Lane's corporate name change to Research Power Corporation.

C. Public Comments

No public comments were received.

II. DISCUSSION AND ANALYSIS

DOE is statutorily obligated under FPA § 202(e) to grant requests for export authorization unless the Department finds that the proposed export would negatively impact either: (i) the sufficiency of electric supply, or (ii) the coordination of the electric grid. Regarding the first exception criterion, DOE shall approve an electricity export application "unless, after opportunity for hearing, it finds that the proposed transmission would impair the sufficiency of electric supply within the United States …." 16 U.S.C. § 824a(e). DOE has interpreted this criterion to mean that sufficient generating capacity and electric energy must exist such that the export could be made without compromising the energy needs of the exporting region, including serving all load obligations in the region while maintaining appropriate reserve levels. *See, e.g.*, *BP Energy Co.*, Order No. EA-314, at 1-2 (Feb. 22, 2007), *renewed*, Order No. EA-314-A, at 2 (May 3, 2012), Order No. EA-314-B, at 2 (Feb. 28, 2017), *renewed,* Order No. EA-314-C, at 4 (Dec. 20, 2021).

Under the second exception criterion, DOE shall approve an electricity export application "unless, after opportunity for hearing, it finds that the proposed transmission would … impede or tend to impede the coordination in the public interest of facilities subject to the jurisdiction of [DOE]." 16 U.S.C. § 824a(e). DOE has interpreted this criterion primarily as an issue of the operational reliability of the domestic electric transmission system. Accordingly, the export must not compromise transmission system security and reliability. *See, e.g.*, Order No. EA-314-C, at 4.

A. Research Power Corporation Will Not Impair the Sufficiency of the Electric Supply in the United States

Sufficiency of supply, the first exception criterion, addresses whether regional electricity needs are met in the current market. DOE has analyzed this issue from both an economic and a reliability perspective. The economic perspective concerns the supply available to wholesale market participants. The reliability perspective focuses on preventing problems that could result from inadequate supplies. Taken together, DOE examines whether existing electric supply is available via market mechanisms, and whether potential reliability issues linked to supply problems are mitigated by reliability enforcement mechanisms.

From an economic perspective, DOE finds that the wholesale energy markets are sufficiently robust to make supplies available to exporters and other market participants serving United States regions along the Canadian and Mexican borders. Following enactment of the Energy Policy Act of 1992, Pub. L. No. 102-486, which encouraged the Federal Energy Regulatory Commission (FERC) to foster competition in the wholesale energy markets through open access to transmission facilities, energy markets developed across the United States to provide opportunities for a more efficient availability of supply. Subsequently, the Energy Policy Act of 2005, Pub. L. No. 109-58, reaffirmed the Government's commitment to competition in wholesale energy markets as national policy. FERC has continued to encourage the expansion of wholesale energy markets through its orders to remove barriers[1] and to ensure that these markets are functioning properly.[2] As a result, market participants have access to traditional bilateral contracts, as well as organized electricity markets run by regional transmission organizations (RTOs) or independent system operators (ISOs). FERC oversees these interstate wholesale electricity markets across most of the lower 48 states. Absent an indication in the record that the geographic markets relevant to this export authorization analysis are flawed and result in

[1] *See, e.g.*, *Preventing Undue Discrimination and Preference in Transmission Service*, Order No. 890, 72 Fed. Reg. 12,266 (Mar. 15, 2007), FERC Stats. & Regs. ¶ 31,241, *order on reh'g*, Order No. 890-A, FERC Stats. & Regs. ¶ 31,261 (2007), *order on reh'g*, Order No. 890-B, 123 FERC ¶ 61,299 (2008), *order on reh'g*, Order No. 890-C, 126 FERC ¶ 61,228 (2009).

[2] *See, e.g.*, *Wholesale Competition in Regions with Organized Electric Markets*, Order No. 719, FERC Stats. & Regs. ¶ 31,281 (2008), *as amended*, 126 FERC ¶ 61,261, *order on reh'g*, Order No. 719-A, FERC Stats. & Regs. ¶ 31,292, *reh'g denied*, Order No. 719-B, 129 FERC ¶ 61,252 (2009).

uneconomic exports that jeopardize regional supply, DOE finds that the proposed transmission for export does not impair the sufficiency of electric supply within the United States.

From a reliability perspective,[3] DOE focuses on the prevention of cascading outages and other problems that could result from inadequate resources.[4] Reliability oversight is addressed by the authority granted to FERC through the Energy Policy Act of 2005. That Act added section 215 to the FPA, which directed FERC to certify an electric reliability organization and develop procedures for establishing, approving, and enforcing mandatory electric reliability standards. 16 U.S.C. § 824o. FERC certified the North American Electric Reliability Corporation (NERC) in 2006 to develop and enforce reliability standards for the bulk-power system in the United States. *Order Certifying NERC as the Electric Reliability Organization and Ordering Compliance Filing*, FERC Docket No. RR06-1-000, 116 FERC ¶ 61,062 (July 20, 2006). FERC approves these standards, at which point they become mandatory and enforceable. NERC Reliability Standards address areas such as resource and demand balancing, critical infrastructure protection, communications, emergency preparedness and operations, facilities design, transmission operations, transmission planning, modelling, nuclear, personnel performance and training, protection and controls, voltage and reactive, interchange scheduling and coordination, and interconnection reliability operations and coordination.

NERC Reliability Standards are enforceable throughout the continental United States, most of Canada south of the 60th parallel, and the Mexican state of Baja California Norte. Through enforcement by FERC, NERC, and six Regional Entities overseen by NERC,[5] all bulk-power system owners, operators, and users are held responsible for complying with reliability standards. The reliability standards are structured so that many entities have overlapping responsibility for the electric grid, thereby resulting in several layers of reliability monitoring. Entities such as reliability coordinators and balancing authorities coordinate power generation and transmission among multiple utilities to serve demand within an integrated regional wholesale market. One of the principal functions of these entities is to schedule adequate generating and reserve capacity. This allows them to serve demand at the regional level and to ensure that there is sufficient power supply to maintain system reliability. Reliability Standard IRO-001-4 "establish[es] the responsibility of Reliability Coordinators to act or direct other entities to act."[6] Requirement R1 states that "[e]ach Reliability Coordinator shall act to address the reliability of its Reliability Coordinator Area via direct actions or by issuing Operating Instructions."[7] Reliability oversight is designed through coordinated efforts amongst Reliability Coordinators to preserve the benefits of interconnected operations and ensure that operations in one area will not adversely impact other areas.[8] Reliability Standard IRO-014-3 R1 provides that "[e]ach Reliability Coordinator shall have and implement Operating Procedures, Operating

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[3] A related reliability analysis follows in the next section of this Order.

[4] This focus should not be confused with resource adequacy planning and capacity requirements that have traditionally been the domain of state regulatory commissions, NERC-certified Regional Entities, and RTOs/ISOs.

[5] The six entities are the Midwest Reliability Organization, Northeast Power Coordinating Council, ReliabilityFirst Corporation, SERC Reliability Corporation, Texas Reliability Entity, and Western Electricity Coordinating Council.

[6] Standard IRO-001-4 (Reliability Coordination – Responsibilities), at ¶ A.3.

[7] *Id.* ¶ B.R1.

[8] *See* Standard IRO-014-3 (Coordination Among Reliability Coordinators), at ¶ A.3.

Processes, or Operating Plans, for activities that require notification or coordination of actions that may impact adjacent Reliability Coordinator Areas, to support Interconnection reliability."[9]

DOE finds that NERC's FERC-approved comprehensive enforcement mechanism ensures that bulk-power system owners, operators, and users have a strong incentive both to maintain system resources and to prevent reliability problems that could result from movement of electric supplies through export. As a result of this reliability oversight, DOE finds that the sufficiency of supply is not impaired by Research Power Corporation's proposed export authorization.

DOE's sufficiency of supply findings are further supported by the fact that power marketers, such as Research Power Corporation, do not have an obligation to serve a franchised territory. Before the current role of power marketers emerged in the industry, the FPA § 202(e) inquiry into sufficiency of supply had a narrower focus and was designed for an applicant that was a vertically integrated utility[10] with an obligation to serve native load. Under that traditional scenario, the inquiry regarding sufficiency of supply logically sought to confirm that exports would be surplus to the needs of a vertically-integrated utility's native load obligations and reserve margins. As explained in DOE's notice of the first application by a power marketer for export authorization, the sufficiency of supply inquiry became unnecessary when applied to power marketers:

> The Applicant also is required to demonstrate that it would have sufficient generating capacity to sustain the proposed export under the terms and conditions of its export agreement, while still complying with any established reserve criteria.
>
> Since marketers generally could not be seen as having any "native load" requirements, the latter criterion of maintaining sufficient reserve margins appears inappropriate and unnecessary in this instance.

59 Fed. Reg. 54900 (Nov. 2, 1994). Power marketers do not have franchised service areas and, consequently, do not have native load obligations like a traditional local distribution utility that could be impaired by exports.

In sum, market mechanisms and reliability oversight protect against the possibility that Research Power Corporation's exports would jeopardize domestic sufficiency of supply. Therefore, an export by Research Power Corporation would not trigger the first exception criterion of FPA § 202(e) regarding the sufficiency of electric supply within the United States.

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[9] *Id.* ¶ B.R1.

[10] The Supreme Court of the United States has explained: "In 1935, when the FPA became law, most electricity was sold by vertically integrated utilities that had constructed their own power plants, transmission lines, and local delivery systems…[M]ost operated as separate, local monopolies subject to state or local regulation. Their sales were 'bundled,' meaning that consumers paid a single charge that included both the cost of the electric energy and the cost of its delivery. Competition among utilities was not prevalent." *New York v. FERC*, 535 US 1, 5 (2002).

B. Research Power Corporation's Requested Authorization Will Not Adversely Affect Either the Reliability or the Security of the United States Electric Transmission System

Reliability, the second exception criterion under FPA § 202(e), addresses operational reliability and security of the domestic electric transmission system. In evaluating the operational reliability impacts of export proposals, DOE has used a variety of methodologies and information, including established industry guidelines, operating procedures, and technical studies where available and appropriate. When determining these impacts, it is convenient to separate the export transaction into two parts: (i) moving the export from the source to a border system that owns the international transmission connection, and (ii) moving the export through that border system and across the border.

Moving Electricity to a Border System. Moving electricity for export to a border system necessarily involves the use of the bulk-power system. As noted in the preceding section, bulk-power system reliability concerns are addressed under the FPA by FERC and NERC and involve the enforcement of mandatory reliability standards. These standards ensure that all owners, operators, and users of the bulk-power system have an obligation to maintain system security and reliability. The standards are structured so that there are always entities with broader responsibilities than the applicant, such as reliability coordinators and balancing authorities, to keep a constant watch over the domestic transmission system.

To deliver the export from the source to a border system, the applicant must make the necessary commercial arrangements and obtain sufficient transmission capacity to wheel the exported energy to the border system. The applicant would be expected to follow FERC orders regarding open transmission access and to schedule delivery of the export with the appropriate RTO, ISO, and/or balancing authority (formerly the control area operator).

It is the responsibility of the RTO, ISO, and/or balancing authority to schedule the delivery of the export consistent with established and mandatory operational reliability criteria. During each step of the process of obtaining transmission service, the owners and/or operators of the transmission facilities will evaluate the impact on the system and schedule the movement of the export *only* if it would not violate established operating reliability standards. As a failsafe, the reliability coordinator in each region has the authority and responsibility to curtail, cancel, or deny scheduled flows to avoid shortages or to restore necessary energy and capacity reserves. Reliability Standard EOP-011-1 R2 provides that "[e]ach 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."[11]

Specifically, the reliability coordinator has the authority to suspend exports if the electric energy would be needed to support the regional power grid. *See* Reliability Standard IRO-001-4 R1 ("Each Reliability Coordinator shall act to address the reliability of its Reliability Coordinator Area via direct actions or by issuing Operating Instructions"), R2 ("Each Transmission Operator, Balancing Authority, Generator Operator, and Distribution Provider shall comply with its Reliability Coordinator's Operating Instructions unless compliance with the

[11] EOP-011-1 (Emergency Operations), at ¶ B.R2.

Operating Instructions cannot be physically implemented or unless such actions would violate safety, equipment, regulatory, or statutory requirements”), and R3 (“Each Transmission Operator, Balancing Authority, Generator Operator, and Distribution Provider shall inform its Reliability Coordinator of its inability to perform the Operating Instruction issued by its Reliability Coordinator in Requirement R1”).

DOE has determined that the existing industry procedures for obtaining transmission capacity on the domestic transmission system (described above) provide adequate assurance that any export will not cause an operational reliability problem. Therefore, Research Power Corporation’s export authorization has been conditioned to ensure that the export will not cause operational issues on regional transmission systems to fall outside of established industry reliability criteria, or cause or exacerbate a transmission operating problem on the United States’ electric power supply system (*see* Order below, Section VII, paragraphs C, D, and I).

Moving Electricity Through a Border System. The second part of DOE’s reliability inquiry, addressing the transmission of the export through a border system and across the border, is a question of whether the border system is reliable and secure. To a large extent, this question is addressed by the jurisdiction of NERC. NERC and Regional Entities—including the Midwest Reliability Organization, the Northeast Power Coordinating Council, and the Western Electricity Coordinating Council—oversee the United States-Canadian border system and a significant part of the United States-Mexican border system. Those border systems are generally subject to the same reliability standards as domestic systems. *See, e.g.*, http://www.ieso.ca/sector-participants/system-reliability/reliability-standards-framework.

DOE also relies on the System Impact Studies submitted in conjunction with an application for a DOE-issued Presidential permit[12] to construct a new international transmission line. As DOE has previously reviewed System Impact Studies submitted with Presidential permit applications,[13] DOE does not need to perform additional impact assessments here, provided the maximum rate of transmission for all exports through a border system does not exceed the authorized limit of the system (*see* Order below, Section VII, paragraph (A)). In its application, Research Power Corporation committed to complying with all reliability limits on border facilities. *See* App. at 3. The second part of the reliability inquiry is therefore satisfied by DOE regulatory oversight, in addition to NERC’s reliability enforcement.

III. FINDINGS AND DECISION

A. Research Power Corporation Meets the Statutory Requirements to Export Electric Energy to Canada

[12] DOE issues Presidential permits pursuant to Executive Order 10,485, as amended by Executive Order 12,038. *See* 10 C.F.R. §§ 205.320-205.329.

[13] *See, e.g.*, *AEP Tex. Cent. Co.*, Order No. PP-317, at 2-3 (Jan. 22, 2007); *Mont. Alta. Tie Ltd.*, Order No. PP-305, at 2-4 (Nov. 17, 2008).

As explained above, DOE has assessed the impact that the proposed export would have on the reliability of the United States electric power supply system. DOE has determined that the export of electric energy to Canada by Research Power Corporation, as ordered below, would not impair the sufficiency of electric power supply within the United States and would not impede or tend to impede the coordination in the public interest of facilities within the meaning of FPA § 202(e).

B. Research Power Corporation Qualifies for a NEPA Categorical Exclusion for Exports of Electric Energy

Research Power Corporation's Application qualifies for DOE's categorical exclusion for exports of electric energy under the National Environmental Policy Act of 1969, as amended (NEPA), 42 U.S.C. § 4321 *et seq*. DOE's NEPA Implementing Procedures (June 2025) set forth this categorical exclusion, codified as "B4.2," as follows:

> Export of electric energy as provided by Section 202(e) of the Federal Power Act over existing transmission lines or using transmission system changes that are themselves categorically excluded.

10 C.F.R. Part 1021, App. B, § B4.2.

DOE has determined that actions in this category do not normally have a significant effect on the human environment and that, therefore, neither an environmental assessment nor an environmental impact statement normally is required. 10 C.F.R. § 1021.102(a).

To invoke this categorical exclusion, DOE must determine that, in relevant part, "[t]here are no extraordinary circumstances related to the proposal that may affect the significance of the environmental effects of the proposal." 10 C.F.R. § 1021.102(b)(2). "Extraordinary circumstances" include "unique situations" such as "scientific controversy about the environmental effects of the proposal; uncertain effects or effects involving unique or unknown risks; and unresolved conflicts concerning alternative uses of available resources." *Id*. DOE finds that granting Research Power Corporation's request for export authorization does not present such extraordinary circumstances. Research Power Corporation seeks to deliver electricity over existing international electric transmission facilities, which fits squarely within the B4.2 categorical exclusion. For these reasons, DOE will not require more detailed NEPA review in connection with this Application.

C. Conclusion

DOE grants Research Power Corporation's request for export authorization. Research Power Corporation is authorized to export electricity to Canada over any authorized international transmission facility that is appropriate for open access transmission by third parties, subject to the limitations and conditions described in this Order. The authorization shall be effective for a five (5) year term consistent with DOE's standard term for new electricity export authorizations.

IV. DATA COLLECTION AND REPORTING REQUIREMENTS

The responsibility for the data collection and reporting under orders authorizing electricity exports to a foreign country currently rests with the U.S. Energy Information Administration (EIA) within DOE. The Applicant is instructed to follow EIA instructions in completing this data exchange. Questions regarding the data collection and reporting requirements can be directed to EIA by email at EIA4USA@eia.gov or by phone at 1-855-342-4872.

Additionally, any change to the tariff of an entity with an export authorization must be provided to DOE's Grid Deployment Office via email at *electricity.exports@hq.doe.gov*. 10 C.F.R. § 205.308(b).

V. COMPLIANCE

Obtaining a valid order from DOE authorizing the export of electricity under FPA § 202(e) is a necessary condition before engaging in the export. Failure to obtain such an order or continuing to export after the expiration of such an order may result in a denial of authorization to export in the future and subject the exporter to sanctions and penalties under the FPA. DOE expects transmitting utilities owning border facilities and entities charged with the operational control of those border facilities, such as ISOs, RTOs, or balancing authorities, to verify that companies seeking to schedule an electricity export have the requisite authority from DOE to export such energy.

DOE expects Research Power Corporation to abide by the terms and conditions established for its authority to export electric energy to Canada, as set forth below. DOE intends to monitor Research Power Corporation compliance with these terms and conditions, including the requirement in paragraph G of this Order that Research Power Corporation create and preserve full and complete records and file reports with EIA as discussed above.

A violation of any of these terms and conditions, including the failure to submit timely and accurate reports, may result in the loss of authority to export electricity and subject Research Power Corporation to any applicable sanctions and penalties under the FPA.

VI. OPEN ACCESS POLICY

An export authorization issued under FPA § 202(e) does not impose a requirement on transmitting utilities to provide service. However, DOE expects transmitting utilities that own border facilities to provide open access transmission service across the border in accordance with the principles of comparable open access and non-discrimination contained in the FPA and articulated in FERC Order No. 888 (Promoting Wholesale Competition Through Open Access Non-Discriminatory Transmission Services by Public Utilities, FERC Statutes and Regulations ¶ 31,036 (1996)), as amended. The actual rates, terms, and conditions of transmission service should be consistent with the non-discrimination principles of the FPA and the transmitting utility's Open-Access Transmission Tariff on file with FERC.

All recipients of export authorizations, including owners of border facilities for which Presidential permits have been issued, are required by their export authorization to conduct operations in accordance with the applicable principles of the FPA and any pertinent rules, regulations, directives, policy statements, and orders adopted or issued thereunder, including the comparable open access provisions of FERC Order No. 888, as amended. Cross-border electric trade ought to be subject to the same principles of comparable open access and non-discrimination that apply to transmission in interstate commerce. *See Enron Power Mktg., Inc. v. El Paso Elec. Co.*, 77 FERC ¶ 61,013 (1996), *reh'g denied*, 83 FERC ¶ 61,213 (1998). Thus, DOE expects owners of border facilities to comply with the same principles of comparable open access and non-discrimination that apply to the domestic, interstate transmission of electricity.

VII. ORDER

Accordingly, pursuant to FPA § 202(e) and the Rules and Regulations issued thereunder (10 C.F.R. §§ 205.300-309), it is hereby ordered that Research Power Corporation is authorized to export electric energy to Canada under the following terms and conditions:

(A) The electric energy exported by Research Power Corporation pursuant to this Order may be delivered to Canada over any authorized international transmission facility that is appropriate for open access transmission by third parties in accordance with the export limits authorized by DOE.

(1) The following international transmission facilities located at the United States border with Canada are currently authorized by Presidential permit and available for open access transmission:[14, 15]

Owner	**Location**	**Voltage**	**Permit No.**[16]
Bangor Hydro-Electric Company	Baileyville, ME	345 kV	PP-89
Basin Electric Power Cooperative	Tioga, ND	230 kV	PP-64
Bonneville Power Administration (BPA)	Blaine, WA	2x 500 kV	PP-10
	Nelway, WA	230 kV	PP-36
	Nelway, WA	230 kV	PP-46
CHPE, LLC	Champlain, NY	±230 kV DC	PP-481[17]

[14] This Order authorizes the export of electricity over any "authorized international transmission facility," which is intended to include both large transmission lines and smaller distribution lines that have received a Presidential permit. However, the list in subparagraph (A)(1) of current facilities only includes transmission lines.

[15] The Applicant submitted a list identifying currently authorized transmission facilities (Attachment 1 of the Application). However, as information about some of those facilities may have changed since the Application was submitted, the table of transmission facilities in this Order may differ from the Applicant's submission to reflect those changes.

[16] These Presidential permit numbers refer to the generic DOE permit number and are intended to include any subsequent amendments to the permit authorizing the facility.

[17] Currently under construction and not yet operational as of September 2025.

Eastern Maine Electric Cooperative	Calais, ME	69 kV	PP-32
International Transmission Company	Detroit, MI	230 kV	PP-230
	Marysville, MI	230 kV	PP-230
	St. Claire, MI	230 kV	PP-230
	St. Claire, MI	345 kV	PP-230
Lake Erie Connector Transmission, LLC	Erie County, PA	320 kV	PP-412[18]
Long Sault, Inc.	Massena, NY	2x 115 kV	PP-24
Maine Electric Power Company	Houlton, ME	345 kV	PP-43
Minnesota Power, Inc.	International Falls, MN	115 kV	PP-78
Minnesota Power, Inc.	Roseau County, MN	500 kV	PP-398
Minnkota Power Cooperative	Roseau County, MN	230 kV	PP-61
Montana Alberta Tie Ltd.	Cut Bank, MT	230 kV	PP-399
NECEC Transmission LLC	Beattie Twp, ME	±320 kV	PP-438[19]
New York Power Authority	Massena, NY	765 kV	PP-56
	Massena, NY	2x 230 kV	PP-25
	Niagara Falls, NY	2x 345 kV	PP-74
	Devils Hole, NY	230 kV	PP-30
Niagara Mohawk Power Corp.	Devils Hole, NY	230 kV	PP-190
Northern States Power Company	Red River, ND	230 kV	PP-45
	Roseau County, MN	500 kV	PP-63
	Rugby, ND	230 kV	PP-231
Sea Breeze Olympic Converter LP	Port Angeles, WA	±450 kV DC	PP-299[20]
TDI New England	Alburgh, VT	±320 kV DC	PP-400[21]

[18] These transmission facilities have been authorized but not yet constructed or placed into operation.
[19] These transmission facilities have been authorized but not yet constructed or placed into operation.
[20] These transmission facilities have been authorized but not yet constructed or placed into operation.
[21] These transmission facilities have been authorized but not yet constructed or placed into operation.

Vermont Electric Power Co.	Derby Line, VT	120 kV	PP-66
Vermont Electric Transmission Co.	Norton, VT	±450 kV DC	PP-76
Vermont Transco LLC	Highgate, VT	120 kV	PP-82
Versant Power	Fort Fairfield, ME	69 kV	PP-497
	Madawaska, ME	138 kV	PP-498
	Easton, ME	7.2 kV	PP-499
	Baileyville, ME	345kV	PP-500

(2) The following are the authorized export limits for the international transmission lines listed above in subparagraph (A)(1):

(a) Exports by Research Power Corporation made pursuant to this Order shall not cause the total exports on facilities authorized by Presidential Permit PP-64 (issued to Basin Electric Power Coop.) to exceed an instantaneous transmission rate of 150 megawatts (MW). The gross amount of energy that Research Power Corporation may export over the PP-64 facilities shall not exceed 900,000 megawatt-hours (MWH) during any consecutive 12-month period.

(b) Exports by Research Power Corporation made pursuant to this Order shall not cause the total exports on the facilities authorized by Presidential Permit PP-32 (issued to Eastern Maine Electric Coop.) to exceed an instantaneous transmission rate of 15 MW. The gross amount of energy that Research Power Corporation may export over the PP-32 facilities shall not exceed 7,500 MWH annually.

(c) Exports by Research Power Corporation made pursuant to this Order shall not cause the total exports on a combination of the facilities authorized by Presidential Permit PP-481-2 (issued to CHPE, LLC) to exceed an instantaneous transmission rate of 1,250 MW.

(d) Exports by Research Power Corporation made pursuant to this Order shall not cause the total exports on a combination of the facilities authorized by Presidential Permit PP-230 (issued to International Transmission Company) to exceed a coincident, instantaneous transmission rate of 2.2 billion volt-amperes (2,200 MVA).

(e) Exports by Research Power Corporation made pursuant to this Order shall not cause the total exports on a combination of the facilities authorized by Presidential Permit PP-412-1 (issued to Lake Erie Connector Transmission, LLC) to exceed an instantaneous transmission rate of 1,000 MW.

(f) Exports by Research Power Corporation made pursuant to this Order shall not cause the scheduled rate of transmission over a combination of facilities authorized by Presidential Permits PP-43 (issued to Maine Electric Power Company) and PP-500 (issued to Bangor Hydro-Electric) to exceed 550 MW.

(g) Exports by Research Power Corporation made pursuant to this Order shall not cause the total exports on the combination of facilities authorized by Presidential Permits PP-497 and PP-498 (issued to Versant Power) to exceed a coincident, instantaneous transmission rate of 134 MW.

(h) Exports by Research Power Corporation made pursuant to this Order shall not cause total exports on the facilities authorized by Presidential Permit PP-78-1 (issued to Minnesota Power, Inc.) to exceed an instantaneous transmission rate of 100 MW. Exports by Research Power Corporation may cause total exports on the PP-78-1 facilities to exceed 100 MW only when total exports between the Mid-Continent Area Power Pool (MAPP) and Manitoba Hydro are below maximum transfer limits and/or whenever operating conditions within the MAPP system permit exports on the PP-78-1 facilities above the 100-MW level without violating established MAPP reliability criteria. However, under no circumstances shall exports by Research Power Corporation cause the total exports on the PP-78-1 facilities to exceed 150 MW.

(i) Exports made by Research Power Corporation pursuant to this Order shall not cause total exports on the facilities authorized by Presidential Permit PP-398 (issued to Minnesota Power, Inc.) to exceed an instantaneous transmission rate of 750 MW.

(j) Exports by Research Power Corporation made pursuant to this Order shall not cause total exports on a combination of the international transmission lines authorized by Presidential Permits PP-45 and PP-63 (issued to Northern States Power Company), PP-61 (issued to Minnkota Power), and PP-231 (issued to Northern States Power Company, d/b/a Excel Energy Inc. (Xcel)), to exceed an instantaneous transmission rate of 700 MW on a firm basis and 1,050 MW on a non-firm basis.

(k) Exports by Research Power Corporation made pursuant to this Order shall not cause the total exports on the facilities authorized by Presidential Permit PP-66 (issued to Vermont Electric Power Co.) to exceed an instantaneous transmission rate of 50 MW. The gross amount of energy that Research Power Corporation may export over the PP-66 facilities shall not exceed 50,000 MWH annually.

(l) Exports by Research Power Corporation made pursuant to this Order shall not cause the total exports on the facilities authorized by Presidential Permit PP-56 (issued to NYPA) to exceed an instantaneous transmission rate of 1,000 MW.

(m) Exports by Research Power Corporation made pursuant to this Order shall not cause: (a) the total exports on the facilities authorized by Presidential Permits PP-25, PP-30, PP-74 (issued to NYPA), and PP-190 (issued to Niagara Mohawk Power Corp.) to exceed a combined instantaneous transmission rate of 1,650

MW; and (b) the total exports on the 115-kV facilities authorized by Presidential Permit PP-24 (issued to Long Sault, Inc.) to exceed an instantaneous transmission rate of 100 MW. In addition, the gross amount of energy that Research Power Corporation may export over the PP-24 facilities shall not exceed 300,000 MWH annually.

(n) Exports by Research Power Corporation made pursuant to this Order shall not cause total exports on the two 500-kV lines authorized by Presidential Permit PP-10, the 230-kV line authorized by Presidential Permit PP-36, and the 230-kV line authorized by Presidential Permit PP-46 (issued to BPA) to exceed the following limits:

Condition	PP-36 & PP-46 Limit	PP-10 Limit	Total Export Limit
All lines in service	400 MW	1500 MW	1900 MW
1-500 kV line out	400 MW	300 MW	700 MW
2-500 kV lines out	400 MW	0 MW	400 MW
1-230 kV line out	400 MW	1500 MW	1900 MW
2-230 kV line out	0 MW	1500 MW	1500 MW

(o) Exports by Research Power Corporation made pursuant to this Order shall not cause a violation of the following conditions as they apply to exports over the facilities authorized by Presidential Permit PP-76-1, as amended (issued to the Vermont Electric Transmission Company):

Exports Through	NEPOOL Load Condition	Export Limit
Comerford converter	Summer, Heavy	650 MW
Comerford converter	Winter, Heavy	660 MW
Comerford converter	Summer, Light	690 MW
Comerford converter	Winter, Light	690 MW
Comerford & Sandy Pond converters	All	2,000 MW

(p) Exports by Research Power Corporation made pursuant to this Order over the international transmission facilities authorized by Presidential Permit PP-399 (issued to Montana Alberta Tie Ltd.) shall not exceed an instantaneous transmission rate of 300 MW.

(q) Exports by Research Power Corporation made pursuant to this Order over the international transmission facilities authorized by Presidential Permit PP-438 (issued to NECEC Transmission LLC) shall not exceed an instantaneous transmission rate of 1,200 MW.

(r) Exports by Research Power Corporation made pursuant to this Order over the international transmission facilities authorized by Presidential Permit PP-299 (issued to Sea Breeze Olympic Converter LP) shall not exceed an instantaneous transmission rate of 550 MW.

(s) Exports by Research Power Corporation made pursuant to this Order shall not cause the total exports on a combination of the facilities authorized by Presidential Permit PP-400 (issued to TDI-New England) to exceed an instantaneous transmission rate of 1,000 MW.

(t) Exports by Research Power Corporation made pursuant to this Order shall neither cause the total exports on the facilities authorized by Presidential Permit PP-82-6 (issued to Vermont Transco LLC) to exceed an instantaneous transmission rate of 250 MW.

(B) Changes by DOE to the export limits in other orders shall result in a concomitant change to the export limits contained in subparagraph (A)(2) of this Order. Changes to the export limits contained in subparagraphs (A)(2)(l), (m), and (n) will be made by DOE after submission of appropriate information demonstrating a change in the transmission transfer capability between the electric systems in New York State and Ontario and New York State and Quebec, and between BPA and BC Hydro or BPA and West Kootenay Power. Notice of these changes will be provided to Research Power Corporation.

(C) Research Power Corporation shall obtain any and all other Federal and state regulatory approvals required to execute any power exports to Canada. The scheduling and delivery of electricity exports to Canada shall comply with all reliability criteria, standards, and guidelines of NERC, reliability coordinators, Regional Entities, RTOs, ISOs or balancing authorities, or their successors, as appropriate, on such terms as expressed therein, and as such criteria, standards, and guidelines may be amended from time to time.

(D) Exports made pursuant to this authorization shall be conducted in accordance with the applicable provisions of the FPA and any pertinent rules, regulations, directives, policy statements, and orders adopted or issued thereunder, including the comparable open access provisions of FERC Order No. 888, as amended.

(E) The authorization herein granted may be modified from time to time or terminated by further order of DOE. In no event shall such authorization to export over a particular transmission facility identified in subparagraphs (A)(1) and (2) extend beyond the date of termination of the Presidential permit or treaty authorizing such facility.

(F) This authorization shall be without prejudice to the authority of any state or state regulatory commission for the exercise of any lawful authority vested in such state or state regulatory commission.

(G) Research Power Corporation shall make and preserve full and complete records with respect to the electric energy transactions between the United States and Canada. Research Power Corporation shall collect and submit the data to EIA as required by and in accordance with the procedures of Form EIA-111, "Quarterly Electricity Imports and Exports Report," and all successor forms.

(H) In accordance with 10 C.F.R. § 205.305, this export authorization is not transferable or assignable, except in the event of involuntary transfer by operation of law. Provided written notice of the involuntary transfer is given to DOE within 30 days, this authorization shall remain in effect temporarily. The authorization shall terminate unless an application for a new export authorization has been received by DOE within 60 days of the involuntary transfer. Upon receipt by DOE of such an application, this existing authorization shall continue in effect pending a decision on the new application. In the event of a proposed voluntary transfer of this authority to export electricity, the transferee and the transferor shall file a joint application for a new export authorization, together with a statement of the reasons for the transfer.

(I) Nothing in this Order is intended to prevent the transmission system operator from being able to reduce or suspend the exports authorized herein, as necessary and appropriate, whenever a continuation of those exports would cause or exacerbate a transmission operating problem or would negatively impact the security or reliability of the transmission system.

(J) Research Power Corporation has a continuing obligation to give DOE written notification as soon as practicable of any prospective or actual changes of a substantive nature in the circumstances upon which this Order was based, including but not limited to changes in authorized entity contact information or NERC compliance registry status.

(K) This authorization shall be effective as of October 21, 2025 and shall remain in effect for a period of five (5) years from that date. Application for renewal of this authorization may be filed within six (6) months prior to its expiration. Failure to provide DOE with at least one hundred and twenty (120) days to process a renewal application and provide adequate opportunity for public comment may result in a gap in Research Power Corporation's authority to export electricity.

Issued in Washington, D.C., on October 21, 2025.

Chris Wright

Chris Wright
Secretary of Energy
U.S. Department of Energy

BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c) Emergency Order: Midcontinent Independent System Operator and Northern Indiana Public Service Company LLC	)	Order No. 202-26-19
Federal Power Act Section 202(c) Emergency Order: Midcontinent Independent System Operator and CenterPoint Energy Indiana South	)	Order No. 202-26-20

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

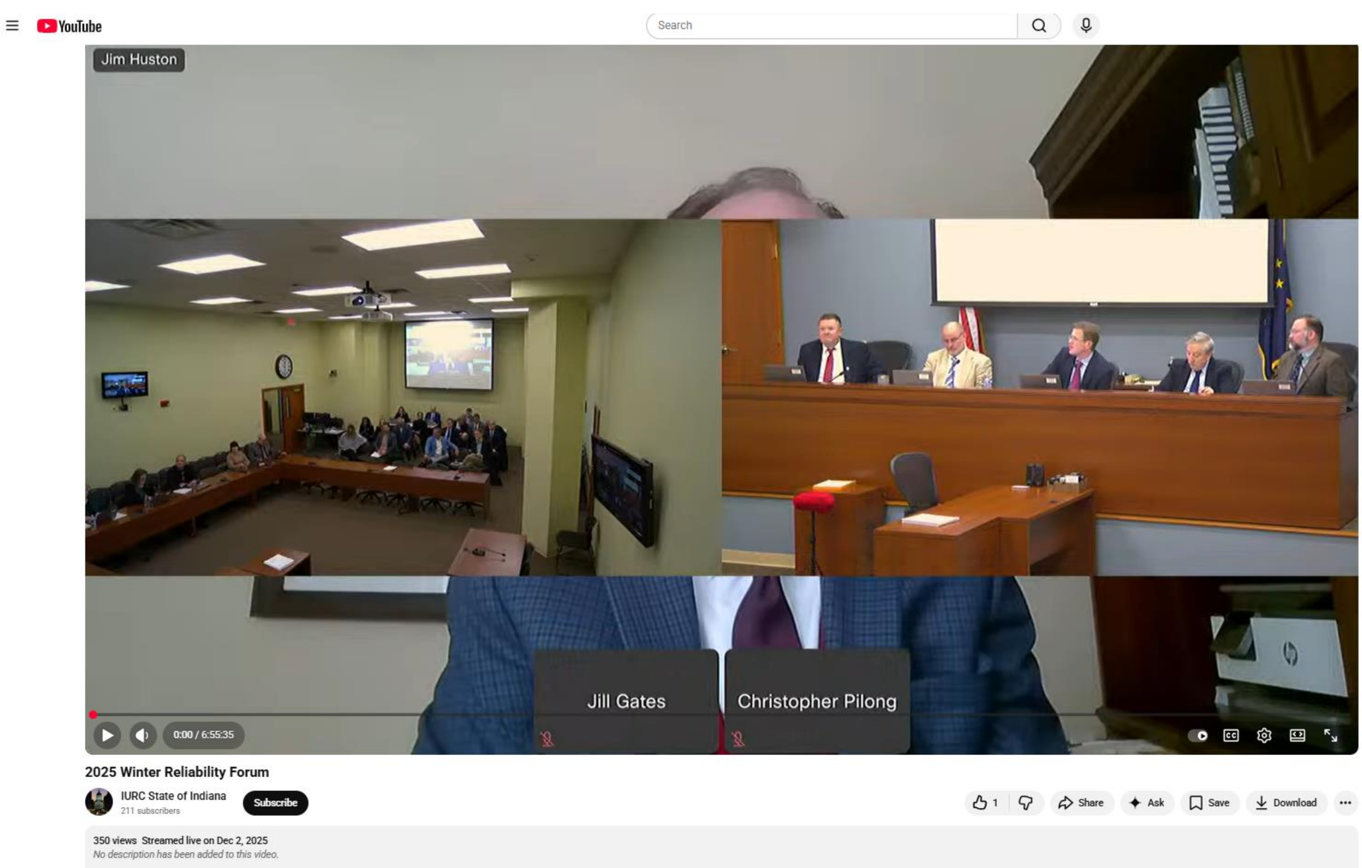
Exhibit 53
IURC 2025 Winter Reliability Forum (December 2, 2025)

Indiana Utility Regulatory Commission

2025 Winter Reliability Forum (December 2, 2025)

Actual exhibit is a digital excerpt in .MP4 format of the video recording, from the 51:00 to 54:09 timestamps of the full recording.

Video recording of the full event is also available on YouTube at:
https://www.youtube.com/watch?v=bCzALF4V45M



BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c) Emergency Order: Midcontinent Independent System Operator and Northern Indiana Public Service Company LLC	)))))	Order No. 202-26-19
Federal Power Act Section 202(c) Emergency Order: Midcontinent Independent System Operator and CenterPoint Energy Indiana South	))))	Order No. 202-26-20

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

Exhibit 54
NARUC Coal Report

Recent Changes to U.S. Coal Plant Operations and Current Compensation Practices

National Association of Regulatory Utility Commissioners | January 2020

Phillip Graeter, Energy Ventures Analysis, Inc.

Seth Schwartz, Energy Ventures Analysis, Inc.

EXHIBIT 15: TYPICAL STARTUP AND CYCLING COSTS FOR A MEDIUM-SIZED COAL-FIRED POWER PLANT ($2019)[19]

Type of Start	Cost category	Cost estimates ($/MW) Expected	Low	High
Hot Start (1–23 h offline)	Maintenance and capital	$ 128	$ 102	$ 162
	Forced outage	$ 60	$ 48	$ 76
	Start-up fuel	$ 20	$ 14	$ 30
	Auxiliary power	$ 11	$ 8	$ 13
	Efficiency loss from low and variable load operation	$ 5	$ 4	$ 8
	Water chemistry cost and support	$ 1	$ 1	$ 2
	Total cycling cost	**$ 225**	**$ 178**	**$ 291**
Warm Start (24 - 120 h offline)	Maintenance and capital	$ 137	$ 109	$ 170
	Forced outage	$ 65	$ 51	$ 80
	Start-up fuel	$ 43	$ 30	$ 57
	Auxiliary power	$ 23	$ 18	$ 28
	Efficiency loss from low and variable load operation	$ 6	$ 5	$ 9
	Water chemistry cost and support	$ 6	$ 4	$ 9
	Total cycling cost	**$ 277**	**$ 217**	**$ 351**
Cold Start (> 120 h offline)	Maintenance and capital	$ 205	$ 162	$ 255
	Forced outage	$ 96	$ 76	$ 120
	Start-up fuel	$ 64	$ 45	$ 24
	Auxiliary power	$ 29	$ 23	$ 36
	Efficiency loss from low and variable load operation	$ 6	$ 5	$ 10
	Water chemistry cost and support	$ 17	$ 13	$ 21
	Total cycling cost	**$ 417**	**$ 325**	**$ 465**
Load follow down to 36% of Capacity	Maintenance and capital	$ 20	$ 12	$ 31
	Forced outage	$ 9	$ 6	$ 15
	Efficiency loss from low and variable load operation	$ 1	$ 1	$ 2
	Mill cycle gas	$ 2	$ 19	$ 50
	Total cycling cost	**$ 32**	**$ 19**	**$ 50**

As shown in **Exhibit 15,** expected costs for cold starts can be almost double the startup cost for a hot start when the remaining temperature in the boiler and turbine system are still significantly higher. However, even hot starts can range from $89,000 to $145,500 per start for a 500 MW coal-fired EGU. These costs can also vary significantly between coal units based on differences in boiler size and design (subcritical vs. supercritical). The highest cost

19 Source: Lefton S A, Hilleman D (2011). *Make your plant ready for cycling operations.* http://www.powermag.com/make-your-plant-ready-for-cycling-operations/

BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c) Emergency Order: Midcontinent Independent System Operator and Northern Indiana Public Service Company LLC	)))))	Order No. 202-26-19
Federal Power Act Section 202(c) Emergency Order: Midcontinent Independent System Operator and CenterPoint Energy Indiana South	))))	Order No. 202-26-20

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

Exhibit 55
IEA Flexibility Report

Increasing the flexibility of coal-fired power plants

Colin Henderson

September 2014

4 Increasing flexibility – turbine and water-steam systems

There is much that can be done to make these areas of a plant more durable, able to respond faster and suffer less efficiency losses. Examples are given in this chapter.

4.1 Reducing stresses during start-up

Start-up, especially from cold, places particularly large stresses on many parts of a coal-fired plant. The turbine is no exception in this regard. Very rapid temperature changes need to be kept to the minimum, while component designs can be adapted to suit. Lindsay and Dragoon (2010) have collected together data from published sources on start-up times for different plant conditions. They found that, generally, coal plants required approximately 12 hours to cold start, 4 hours to warm start, and 1 hour to hot start. There was considerable variation, and this was believed to stem from how hot, warm, and cold starts were defined, and whether those times were actually equipment-limited or not.

One of the requirements for flexibility in the turbine is that the very small clearances between stationary and moving components remain almost constant during output changes. This requires careful design, advanced sealing (*see also* Henderson, 2013) and measures for ensuring uniform thermal loading and applies especially during cold start-up operations (Quinkertz and others, 2008).

Turbine bypass systems are a necessity in plants designed for two-shift (on/off) and other flexible forms of operation. They allow all or part of the steam to bypass the HP turbine or LP turbine so that the rate of steam temperature change in the turbine can be managed as the boiler is starting up and shutting down. This allows thermal stresses in the turbine to be reduced (Lindsay and Dragoon, 2010). This is not to be confused with another type of bypass (HP stage bypass), that can be installed for frequency control in new plants and is described later.

The very high temperature and pressure conditions of USC systems necessitate use of thick-walled components so that they possess adequate strength. Unfortunately, this can limit the rate of temperature change consistent with reducing thermal fatigue to acceptable levels. In the turbine, one means used to counter this is steam cooling of the outer casing to keep its temperature 30–40°C lower than that of the inner casing at the corresponding position along the turbine during load changes. The steam for this is bled radially from points along the inner casing. The steam reduces temperature extremes in the outer casing and allows its thickness to be reduced. The result is that cold start-up time is reduced by almost 50% (Almstedt and others, 2007).

4.2 Load following using sliding pressure operation

While, traditionally, throttling has been used to vary output from a turbine while keeping the pressure constant (Lindsay and Dragoon, 2010), sliding pressure operation has become a commonly applied system in modern supercritical once-through systems (Henderson, 2004). A critical constraint on ramping operation is matching steam and turbine metal temperatures, and more rapid output changes can be achieved using sliding pressure. Sliding pressure also offers advantages over throttle control

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

Exhibit 56
Bradford Coal Inventory Testimony

SOUTHERN INDIANA GAS AND ELECTRIC COMPANY
d/b/a CENTERPOINT ENERGY INDIANA SOUTH
(CEI SOUTH)

IURC CAUSE NO. 38708 FAC 149

DIRECT TESTIMONY

OF

F. SHANE BRADFORD

VICE PRESIDENT OF INDIANA ELECTRIC

ON

PURCHASED POWER AND COAL INVENTORY

SPONSORING ATTACHMENT FSB-1

DIRECT TESTIMONY OF F. SHANE BRADFORD

INTRODUCTION

Q. Please state your name and business address.

A. My name is F. Shane Bradford. My business address is 211 NW Riverside Drive, Evansville, Indiana 47708.

Q. By whom are you employed?

A. I am employed by Southern Indiana Gas and Electric Company d/b/a CenterPoint Energy Indiana South ("CEI South," "Petitioner," or "Company"), which is an indirect subsidiary of CenterPoint Energy, Inc.

Q. On whose behalf are you submitting this direct testimony?

A. I am submitting testimony on behalf of CEI South.

Q. What is your role with respect to Petitioner CEI South?

A. I am the Vice President of Indiana Electric.

Q. Please describe your educational background.

A. I received a Bachelor of Science in Civil Engineering (1992) from the University of Dayton and a Master in Business Administration (2002) from Indiana State University.

Q. Please describe your professional experience.

A. My career in the utility industry began at Dayton Power and Light Co., where I worked in maintenance and production roles within electric generation from 1992 to 1999. I then joined Cinergy's electric generation division until 2003, when I became a plant manager for one of Cinergy's subsidiaries, Trigen Cinergy Solutions LLC. In 2004, I joined CEI South[1] as Power Plant Director, overseeing safe, reliable, and

[1] For the sake of clarity, my testimony refers to CEI South, even though in certain situations, I may be referring to Southern Indiana Gas and Electric Company operating under a prior assumed business name.

environmentally responsible electric generation. By 2021, I transitioned to Director of Power Supply Service, focusing on Wholesale Power Marketing, Market Settlements, and Market Development. In January 2023, I was promoted to Vice President of Power Generation Operations, managing budgeting, operations, maintenance, and personnel decisions for CEI South's generation fleet. In that role, I had responsibility for ensuring customer demand is met sustainably and affordably while complying with environmental regulations. I also oversaw cost inputs for the Integrated Resource Plan ("IRP") process and managed commercial negotiations with generation resources. I assumed my current position in July 2024.

Q. Please describe your present duties and responsibilities as CEI South's Vice-President, Indiana Electric.

A. I am responsible for all operations within CEI South's electric utility sector in Indiana, alongside managing the Company's Generation Transition Plan, as outlined in the 2019/2020 IRP and the 2022/2023 IRP, the latter of which was submitted to the Indiana Utility Regulatory Commission (the "IURC" or "Commission") in May 2023. My responsibilities include the oversight of operations and maintenance ("O&M"), capital budgets, transmission and distribution operations, engineering, generation, development of new renewable projects, and construction of natural gas generation projects to complement renewables.

Q. Have you previously testified before the Indiana Utility Regulatory Commission ("Commission")?

A. Yes. I have testified before the Commission on behalf of CEI South for a certificate of public convenience and necessity ("CPCN") in Cause Nos. 45501, 45564, 45754, 45836, 45847, and 45903. Similarly, I've testified for approval of Power Purchase Agreements ("PPAs") in Cause Nos. 46058 and 46218. Additionally, I have testified on behalf of CEI South in its Fuel Adjustment Clause ("FAC") proceedings and the FAC 137 sub docket under Cause No. 38708; its Clean Energy Cost Adjustment ("CECA") under Cause No. 44909; its Environmental Cost Adjustment ("ECA") under Cause No. 45052; the Midcontinent Independent System Operator ("MISO") Cost and Revenue Adjustment ("MCRA") under Cause No. 43354; and Reliability Cost and

Revenue Adjustment ("RCRA") under Cause No. 43406. I also provided testimony before the Commission in Cause No. 45990 in support of CEI South's electric rate case and in Cause No. 46140 in support of CEI South's request for approval of a disposal agreement to effectuate the sale of CEI South's interest in the Warrick Unit 4 Generating Unit.

Q. What is the purpose of your testimony in this proceeding?

A. The purpose of my testimony is to provide information regarding CEI South's power purchases and related costs as a participant in the MISO Energy Market, CEI South's fuel supply, and to sponsor Attachment FSB-1, which consists of schedules that present the calculations of the MISO components included in fuel costs, the calculations of the daily benchmark prices applicable to purchased power for June 2025 through August 2025 (the "Reconciliation Period"), and information about over-benchmark purchased power costs that are reasonable and recoverable under the applicable settlement. Lastly, I will also present an update to the 2025 coal plan.

MISO

Q. Are you generally familiar with the operations of MISO, including MISO Day 2 Market Initiative and Day 3 Ancillary Services Market ("ASM")?

A. Yes, I am.

Q. Have you reviewed the Commission's June 1, 2005, Order in Cause No. 42685 ("42685 Order") and June 30, 2009, Phase II Order in Cause No. 43426 ("ASM Phase II Order")?

A. Yes.

Q. Is CEI South's proposed recovery of costs for the Reconciliation Period consistent with your understanding of the Commission's 42685 Order and ASM Phase II Order?

A. Yes, CEI South's FAC 149 filing is consistent with my understanding of those Commission Orders.

Q. Please summarize your understanding of the impact of MISO Day 2 on CEI South's operations.

A. MISO's implementation of the Day 2 Market Initiative resulted in operational changes for CEI South. MISO Day 2 features a wide-area security constrained centralized dispatch across a significant geographic footprint spanning 36 Local Balancing Authorities across fifteen states and Manitoba. Through centralized dispatch, this market brings about an integration of system operations and market operations unlike what existed in this region prior to the start of Day 2. This caused both changes to existing operating procedures and the creation of new operational infrastructure. These operational changes result in costs and cost structures that differ in form from those that previously existed.

As a result of the existence of the Day 2 market, the cost for CEI South to serve its native load customers now includes both its own generation and MISO dispatched economic energy purchases.

Q. Briefly describe the MISO costs and revenues that CEI South is seeking to include in this FAC proceeding.

A. Consistent with the 42685 Order, CEI South is requesting that fuel-related MISO costs and revenues track through its current FAC. Attachment FSB-1, Schedule 1, contains a summary of the determination of MISO Components of Fuel Costs, exclusive of purchased power costs, for the Reconciliation Period. In addition, CEI South is requesting recovery of projected MISO costs for the period of February through April 2026 ("FAC Period"). These projected costs include the estimated level of the net effect of delta Locational Marginal Pricing ("LMPs"), Day Ahead and Reliability Assessment Commitment ("RAC") recovery of unit commitment costs, Financial Transmission Right ("FTR") revenue and expenses, and Real Time Marginal Loss Surplus credits.

Q. Are costs associated with MISO's ASM included in the amounts for which you are seeking recovery in this FAC?

A. Yes. Consistent with the Commission's Phase I Order in Cause No. 43426, dated August 13, 2008, CEI South has included for recovery in the FAC those costs for charge types identified as "modified" under the ASM and which were previously recovered in the FAC. Additionally, the Commission issued its ASM Phase II Order on June 30, 2009, that authorized CEI South to include certain new MISO charges and credits as a cost of fuel for recovery in its FAC proceedings.

Q. Did the ASM Phase II Order contain any reporting requirements?

A. Yes. In compliance with the Phase II Order, CEI South must report the monthly average ASM Cost Distribution average dollar per megawatt hours ("MWh") paid for Regulation, Spinning, Supplemental, and Short-Term Reserves. The amounts for the Reconciliation Period are as follows:

	Regulation	Spinning	Supplemental	Short-Term
June 2025	$0.0778	$0.0475	$0.0029	$0.1073
July 2025	$0.0568	$0.0449	$0.0354	$0.2900
August 2025	$0.0516	$0.0342	$0.0206	$0.2759

Q. Given the centralized MISO economic dispatch structure of the Day 2 market, how does CEI South explicitly identify the quantity of purchased power and wholesale sales in each hour?

A. If in a given hour CEI South withdraws more MWh from the grid at its load zone than CEI South generating units inject to the grid, those excess MWh withdrawn are purchased power amounts. Conversely, if in a given hour CEI South generating units inject more MWh to the grid than CEI South withdraws from the grid at its load zone, those excess MWh injected are allocated to wholesale sale amounts.

Q. Is the proposed pass through of Revenue Sufficiency Guarantee ("RSG") amounts in this Cause consistent with your understanding of the Commission's July 16, 2008, Order in Cause No. 43475?

A. Yes.

Q. Are MISO fuel components also included in this FAC?

A. Yes. All the requested MISO components qualify for recovery in this FAC pursuant to the Commission's Orders in Cause Nos. 42685, 43475, 43426, and 38708 FAC 73. In addition, as a result of the Federal Energy Regulatory Commission ("FERC") Order 719 (issued on October 17, 2008) and FERC Order 745 (issued on March 15, 2011) additional charge types have been included for recovery. These charge types were effective June 12, 2012, and discussed in FAC 96 and FAC 97.

PURCHASED POWER RECOVERY

Q. Please describe the mechanism in place for recovery of the cost of energy purchased in MISO Energy Markets.

A. Pursuant to an approved settlement, the cost associated with each purchase is calculated for a given hour as the product of the number of MW purchased for that hour and the purchase price for that hour. To assist in the FAC review of the reasonableness of power purchases, the settlement provides that a benchmark price is applied to purchases and any purchases made in the course of MISO's economic dispatch regime to meet jurisdictional retail load are a cost of fuel and are fully recoverable in the FAC up to the benchmark.

Above-benchmark purchases are also recoverable, so long as the purchases can be shown to be reasonable based on an evaluation conducted with factors set forth in the settlement. As explained by the Commission in Cause No. 41363:

> Our March 10, 1999, Docket Entry was clear that we contemplated that a benchmark would merely be a triggering mechanism-that is, if a benchmark is exceeded the utility would have the opportunity to submit additional evidence demonstrating the reasonableness of its power purchases for cost recovery purposes. Every electric generating utility should have the opportunity to request recovery of and justify the reasonableness of purchased power costs above the benchmark. In the event a utility exceeds the benchmark, the standard to be used to review such purchases will be of the reasonableness of the decisions under the circumstances which were known (or which reasonably should have been known) at the time the purchases were made, not an after the fact focus using hindsight judgment.

(IURC Order, Aug. 18, 1999, p. 11).

Q. What is CEI South's benchmark for purchased power costs?

A. In Cause No. 43414, the Commission approved the establishment of daily benchmarks. The daily benchmarks are established based upon a generic Gas Turbine ("GT"), using a generic GT heat rate of 12,500 Btu/kWh, and using the NYMEX Henry Hub Gas Day Ahead price plus $0.60/MMBtu gas transport charge for a generic gas-fired GT. Changes were approved in Cause No. 43414 to the parameters used to determine amounts over the daily benchmarks.

Q. Is a Schedule showing the Daily Benchmarks for purchased power for the Reconciliation Period included in this Cause?

A. Yes. Attachment FSB-1, Schedule 2, presents the Daily Benchmark amounts for each day in the Reconciliation Period.

Q. What are the amounts of purchased power in excess of the Daily Benchmarks incurred by CEI South during the Reconciliation Period?

A. As shown on Attachment FSB-1, Schedule 3, CEI South determined that purchased power costs exceeded the Daily Benchmarks during the Reconciliation Period as follows: June 2025, $2,596,988.28; July 2025, $3,604,233.44; and August 2025, $1,556,991.21. These costs were incurred pursuant to MISO's security constrained economic dispatch across its footprint because MISO elected to utilize other generation when CEI South needed additional power.

Q. Are all over-benchmark purchases during the Reconciliation Period determined to be recoverable?

A. No. Applying the criteria established by the Benchmark Settlement, CEI South has determined that $159,908.71 of the $7,758,212.93 over benchmark purchases are non-recoverable. The remaining $7,598,304.22 over benchmark purchases are recoverable. Attachment FSB-1, Schedule 3 provides the reason each purchase was made. As contemplated by the Commission in its Order in Cause No. 42770, all these purchases were within "the utility's reasonably expected cost of purchased power under an economic dispatch regime." CEI South acted appropriately in the operation of its generation and its participation in MISO to maintain safe, adequate, and reliable service to its retail customers. The beneficiaries of these purchases were CEI South's retail customers. Without these purchases, CEI South could not have met the demands of its retail customers while complying with MISO dispatch instructions. Recovery of these purchased power costs only makes CEI South whole for costs incurred to meet the demand of retail customers.

Q. Why does MISO at times choose to instruct CEI South to purchase from the market rather than operate generation internal to its control area?

A. Since the 42685 Order, MISO has dispatched generation. MISO first considers its security constrained economic dispatch model to determine what generation is necessary to meet the next day's system demand with the lowest total cost. If this evaluation shows that the total daily cost is predicted to be less using market purchases rather than calling for CEI South's internal generation, then that is the MISO directive CEI South will be given for the Day Ahead market. Additional consideration will be given to the potential impact to system congestion, which is impacted by market purchases versus CEI South peaking generation operation. The summation of these variables is that every day's evaluation has a different set of conditions and inputs which can only be evaluated by MISO on a regional basis. Thus, like any generator, CEI South is sometimes required by MISO to make economic purchases at the lowest cost reasonably possible. With the influx of new generation sources such as wind, and the dramatic reduction in gas prices, other generation sources now are available in the market at competitive prices. Some of these sources, like wind, are so inexpensive in off peak hours that they are selected in the Day Ahead market. The reasonable purchase costs reflected in the FAC are the product of MISO's economic dispatch.

Q. Does CEI South ever deviate from MISO dispatch in order to operate its gas peaking generation?

A. Generally, CEI South follows instructions from MISO on when to operate gas peaking generation. CEI South's on-duty system generation operators are provided plans from MISO, and they follow those dispatch plans. Most often, MISO will call on peaking units in the Real Time (intra-day) market but will on occasion also call for a Peaker through the Day Ahead market. The system generation operators will generally vary from these MISO plans only when notified by local transmission system operators that there is a local distribution or transmission constraint that would be eliminated by the use of peaking generation.

In terms of determining whether to operate the peaking units for purely economic reasons, CEI South's system generation operator evaluates the Real Time Market price of power and compares it to the alternative of starting a natural gas peaking unit for a brief period. The operator monitors the five-minute price signals to determine if they believe the hourly market price will integrate high enough to justify starting a gas turbine. This determination is made knowing that the next five-minute price signal will likely change. A higher price often exists due to an event on the system that sends a price signal for generators to increase production. Once generation is increased, the price will drop; therefore, given these conditions the operator will almost always choose to follow the MISO dispatch signal rather than betting on a sustained higher price.

In addition, when evaluating the operation of a specific gas turbine, the operator must consider, among other things, (1) the time it takes to bring the unit on line, (2) the actual cost of fuel consumed during the period of time from initial firing until the unit is synchronized to the system, as well as the cost of gas used during controlled unit shut down, and (3) the likelihood that the unit will run at a reduced capacity factor, which increases the heat rate, adding to run costs. These must be spread over the total cost of the MWh produced by the machine. These are reasons why the cost of production during short periods often exceeds the price of power purchased from the economic marketplace.

Moreover, failure to comply with MISO's dispatch directive would result in assessment of uninstructed deviation charges of unknown amounts to CEI South. Given these cost and price risks, absent unusual market conditions, it is unlikely CEI South will ignore MISO dispatch and operate its peaking units for economic reasons.

Q. Are any purchases from the Benton County Wind Farm ("BCWF") and Fowler Ridge II ("FRII") included in this FAC?

A. Yes. Pursuant to the approval received in Cause No. 43259, CEI South began receiving power from BCWF on May 7, 2008, when the facility began commercial operation. CEI South's Renewable Energy Purchase Agreement ("REPA") with FRII was approved in Cause No. 43635 on June 17, 2009, and FRII began commercial operation on December 16, 2009. Consistent with the order in Cause No. 43635, CEI South has included in this FAC those charges or credits related to the REPA that are treated by the Commission as components of fuel.

Q. Are there any amounts shown as purchased power from BCWF and FRII included in the monthly work papers?

A. Yes. The details of power purchased from BCWF and FRII are included in the confidential work papers provided to the OUCC.

Q. How has CEI South estimated the generation received from BCWF in this FAC?

A. In response to the fluctuations in CEI South's share of generation of BCWF, CEI South's projections reflect recent historical output from BCWF. CEI South has created an output profile for BCWF that is based on CEI South's monthly average actual share of generation received from BCWF since March 2013 when BCWF was designated a Dispatchable Intermittent Resource ("DIR"). CEI South will update this output profile and its estimates for BCWF in each future FAC based on recent historical data.

Q. Have negative LMPs from BCWF or FRII been experienced?

A. Yes. LMPs can be negative whenever there is congestion on a node. MISO uses negative pricing to rein in a bottleneck, which can occur with wind energy. For the FAC period there were 103 hours when the LMP was negative at BCWF, and 10 hours when the LMP was negative at FRII. This resulted in total charges of $10,626.28.

Q. Please describe how CEI South uses the DIR designation.

A. MISO has attempted to address the operational challenges associated with the variable nature of wind power by allowing these resources to participate fully in MISO's economic dispatch under a DIR resource designation. After consulting with MISO regarding requirements and stipulations around registering wind farms, CEI South was notified that it was required to register BCWF as a DIR. The registration was completed in December 2012, and BCWF became a DIR on March 1, 2013. CEI South is not required to register FRII as a DIR because it meets an exception through its firm transmission into MISO.

Q. How has DIR impacted CEI South and its customers?

A. Generally, since BCWF was registered as a DIR in March of 2013, generation output for CEI South customers has been reduced.

Q. Does CEI South have new power purchase agreement ("PPA") resources anticipated to become available in the next 12 months? If so, please provide the resource type, installed capacity, and the anticipated commercial operation date ("COD").

A. Yes, CEI South has three (3) renewable PPA resources with an anticipated COD in the next 12 months:

1. Salt Creek Wind PPA (170 MW) – anticipated COD of Q1 2026.
2. Wheatland Solar PPA (150 MW) – anticipated COD of Q1 2026.
3. Galesburg Wind PPA (147 MW) – anticipated COD of Q3 2026.

SALES OF RENEWABLE ENERGY CERTIFICATES

Q. Did CEI South include sales of Renewable Energy Certificates ("RECs") in this FAC?

A. Yes. Sales of RECs were recorded in the Reconciliation Period. The net amounts of those sales are included, as reductions to the cost of purchased power, in the calculation of purchased power costs for the respective months. For the Reconciliation Period, purchased power costs have been reduced by the net REC sales proceeds of $(792,086.90).

FUEL FOR GENERATION

Q. What sources of fuel does CEI South use for generating purposes, and what costs are incurred?

A. CEI South utilizes coal and natural gas for electric generation and incurs the costs of purchasing those fuels, including fuel-related transportation and storage costs. In addition, CEI South has solar, wind, battery storage, and landfill gas as part of the electric generation portfolio.

Q. Please describe CEI South's coal purchasing practices.

A. CEI South utilizes Indiana coal as its primary fuel source for electric generation. Coal is purchased primarily under a multi-year contract to maintain a reliable source of coal.

Q. Has CEI South made every reasonable effort to provide power as economically as possible?

A. Yes. CEI South's generating units are offered into the MISO Day Ahead and Real Time markets and are dispatched by the MISO on an economic basis. CEI South has contracted through competitive processes to purchase its coal requirements from a nearby mine at a reasonable market price. Purchasing from a mine in close proximity to CEI South's generating stations helps minimize transportation costs while providing a reliable, reasonably priced fuel supply.

COAL INVENTORY AND CULLEY UNIT 3 UPDATE

Q. What is the status of CEI South's coal inventory?

A. As of October 31, 2025, coal inventory at CEI South's coal-fired generating plant(s) stood at approximately 354,195 tons. This is an increase of 66,158 tons from the inventory level reported in FAC 148.

Q. Please provide the month-ending coal inventory level for Culley Generating Station.

A. The following table shows the month-ending coal inventory for 2025.

Month	Culley
January	226,197
February	241,106
March	307,436
April	327,859
May	284,583
June	307,345
July	288,037
August	289,218
September	317,183
October	354,195
November	
December	

Q. What is the contributing factor for the increased coal inventory in recent months?

A. Culley Unit 3 started its scheduled major turbine overhaul outage in early September. The outage is scheduled to last into late November; however, an unexpected delay with the turbine overhaul may push the unit return into early December. In addition, Culley Unit 2 operation is limited during the Culley Unit 3 scheduled outage due to National Pollutant Discharge Elimination System ("NPDES") wastewater permitting requirements.

Q. Does CEI South have an inventory target to assure reliability?

A. Yes. CEI South's target inventory is driven in part by the risk CEI South is willing to take regarding deliveries being suspended due to a mine issue (safety, Mine Safety and Health Administration, productivity issues, employee retention or strike, etc.), or truck transportation issues (equipment issues or employee retention or strikes), and how long these supply interruptions might reasonably be expected to last. The target inventory also attempts to account for the carrying costs for holding the inventory. Considering these various factors of mine risks, transportation risks, and carrying costs, CEI South generally targets a reserve inventory of about 60 days ± 30 days dependent on contractual commitment. The level of burn can vary, and therefore, target inventory should fall within a range. For CEI South's operating purposes, inventory of approximately [redacted] tons is considered a reasonable target.

Q. What is a contributing factor for the increased coal inventory over CEI South's target range?

A. Culley Unit 3 experienced a main transformer failure forced outage on February 15, 2025, due to an external electrical system disturbance believed to be a lightning strike. Culley Unit 3 remained offline for approximately 9 weeks to replace the main transformer. Culley Unit 3 returned to service on April 18, 2025. Also, as mentioned above, Culley Unit 2 operation was limited during the Culley Unit 3 forced outage due to NPDES wastewater permitting requirements. The combination of Culley Unit 3 forced outage and Culley Unit 2 operational limitations caused the coal inventory to increase.

COAL SUPPLY PLAN

Q. Please summarize CEI South's 2025 coal supply to include delivery options with [redacted].

A. CEI South entered 2025 with 263,321 tons of coal in inventory. For 2025, CEI South has in place coal deliveries priced under one contract previously reviewed by the Commission. Because CEI South negotiated the ability to adjust the contract amount in any given year, CEI South can reduce the total 2025 specified contract volume of [redacted] tons to a firm commitment of [redacted] tons or increase the firm commitment to [redacted] tons. The table below shows the contract, and the [redacted] associated with each.

2025 Contract	Contracted Volume	[redacted]	[redacted]
[redacted] Contract	[redacted]	[redacted]	([redacted])

The following table shows the contract [redacted] that can be exercised.

2025 Contract	Contracted Volume	[redacted]	[redacted]
[redacted] Contract	[redacted]	[redacted]	[redacted]

The [redacted] must be decided by [redacted] of the year prior to the actual year the coal is taken or, in this case, by [redacted] for coal to be taken in 2025. [redacted] CEI South decided to exercise the [redacted] to decrease the contract volume by [redacted].

[redacted] must be decided [redacted] before the beginning of each calendar quarter. CEI South did not choose to exercise the first [redacted] 2025 [redacted] to adjust the contract [redacted]. For the second 2024 [redacted], CEI South chose to decrease the contract by [redacted]. [redacted].

Q. Please provide an update to the 2025 coal plan.

A. The following table shows the 2025 starting inventory, forecasted contractual deliveries, projected coal burn, total available inventory, and ending inventory in 2025 – making the 2025 year-end inventory [redacted] than the target range stated above.

2024 Ending Inventory	[redacted]
2025 Projected Contractual Deliveries	[redacted]
2025 Projected Coal Burn	[redacted]
2025 Projected Year-end Inventory	[redacted]

Q. Can CEI South manage contractual obligations without creating a Culley coal pile inventory concern?

A. Yes. CEI South and the coal supplier have agreed [redacted] which should avoid exceeding Culley's coal pile maximum limitation.

SOLAR GENERATION

Q. What was the total Troy Solar field generation for the Reconciliation Period?

A. Production for the Reconciliation Period from the Troy Solar field was 34,888 MWh. "Solar Generation" production estimates for the FAC Period are included on Petitioner's Exhibit 2, Attachment BKA-2, Schedule 1, Line 6.

Q. What was the total Posey Solar field generation for the Reconciliation Period?

A. Production for the Reconciliation Period from the Posey Solar field was 140,483 MWh. "Solar Generation" production estimates for the FAC Period are included on Petitioner's Exhibit 2, Attachment BKA-2, Schedule 1, Line 6.

CONFIDENTIALITY

Q. What portions of this testimony is CEI South requesting to be treated as confidential information?

A. CEI South's confidentiality request relates to the pricing for winter gas procurement, [redacted] with some coal supply contracts as well as other contractual terms, re-pricing of coal contracts and other concessions, tonnage figures calculated using such optionality, and other details related to costs ("Confidential Provisions"). Confidentiality also relates to rail transportation rates, fuel surcharges, competitive bids, and minimum requirements.

Q. Why has CEI South requested that such information be treated as confidential?

A. These Confidential Provisions of the testimony contain pricing for gas procurement and [redacted] and other confidential terms that were negotiated between CEI South and its natural gas and coal suppliers. If the pricing and optionality became generally known or readily ascertainable to the other parties with whom CEI South is negotiating or to other utilities with whom CEI South would compete, this knowledge would provide considerable economic value to such parties. In effect, knowledge of pricing and optionality provisions by other suppliers would establish a floor in future negotiations, thereby limiting the potential terms and benefits that could accrue to ratepayers, shareholders, and CEI South. Knowledge of the pricing and optionality provisions by potential coal suppliers could enable them to gain an unfair advantage in future competitive situations and negotiate a lower price and optionality provision than would otherwise be possible. The lower optionality provisions would diminish the flexibility available to CEI South's operations to the disadvantage of CEI South and its customers. Further, disclosure of the coal suppliers' optionality provisions would be of significant value to the coal suppliers' competitors, which could prove harmful to the coal suppliers. In addition, CEI South requests that coal transportation rates, competitive bids, and contract terms remain confidential to protect supplier’s confidential information as well as the economic value competitive parties could gain from this information in an open energy market. CEI South is requesting that, pursuant to Indiana Code § 5-14-3-4(a)(4), the Commission find that the Confidential Provisions of the Contract contain “trade secrets” as that term is defined in Indiana Code § 24-2-3-2 and are thereby exempt from public access.

Q. Has CEI South taken any steps to maintain the confidentiality of this information?

A. Yes. In accordance with Indiana Code § 24-2-3-2, the information contained in the Confidential Provisions of the testimony has been the subject of efforts that are reasonable under the circumstances to maintain its secrecy. Within CEI South, this information will be disclosed only to those people directly involved with negotiating coal supply contracts. Outside of CEI South, this information will be disclosed only to individuals who have signed a confidentiality agreement.

CONCLUSION

Q. Does this conclude your direct testimony?

A. Yes, at the present time.

VERIFICATION

I affirm under penalties for perjury that the foregoing representations are true to the best of my knowledge, information, and belief.

SOUTHERN INDIANA GAS AND ELECTRIC
COMPANY D/B/A CENTERPOINT ENERGY
INDIANA SOUTH

F. Shane Bradford

F. Shane Bradford
Vice President, Power Generation Operations

November 17, 2025
Date

CENTERPOINT ENERGY INDIANA SOUTH
Determination of MISO Components of Fuel Cost
June, July and August 2025

Line No.	Energy Market & ASM FAC Adjustment Components	Actual June 2025	Actual July 2025	Actual August 2025
1	Delta LMP	$ (148,004.48)	$ (810,518.54)	$ (1,460,922.32)
2	DA Virtuals Bids and Offers for Load	-	-	-
3	DA RSG 1st Pass Distribution Amount	14,735.60	15,696.67	10,650.97
4	DA RSG Make Whole Payment	(17,738.24)	(3,472.15)	(5,518.77)
5	DA Regulation Amount	(46,774.60)	(46,558.86)	(52,063.49)
6	DA Spinning Reserve Amount	(12,880.90)	(16,700.30)	(7,672.89)
7	DA Supplemental Reserve Amount	(10.47)	(1,002.58)	(165.95)
8	DA Ramp Capability Amount	(29,591.63)	(5,130.38)	(4,280.58)
9	DA Short-Term Reserve Amount	(43,785.31)	(122,243.92)	(86,526.39)
10	RT Marg. Loss Surplus Credit	(96,308.32)	(402,602.04)	(272,635.05)
11	RT Virtuals Bids and Offers for Load	-	-	-
12	RT RSG 1st Pass Distribution Amount	18,413.41	8,903.88	13,494.89
13	RT RSG Make Whole Payment Amount	(53,153.73)	(12,687.61)	(6,272.18)
14	RT Price Volatility Make Whole Payment Amount	(8,754.24)	(16,332.68)	(13,287.85)
15	RT Net Inadvertent Energy	8,426.37	(14,481.99)	2,601.68
16	RT Revenue from Uninstructed Deviation	-	-	-
17	RT Uninstructed Deviation	-	-	-
18	RT Demand Response Allocation Uplift Charge	0.16	7.65	4,148.79
19	RT Regulation Amount	13,020.53	17,984.74	14,483.09
20	RT Spinning Reserve Amount	180.68	8,783.55	(2,736.80)
21	RT Supplemental Reserve Amount	(408.30)	(299.94)	(358.87)
22	RT Regulation Cost Distribution Amount	39,843.63	31,988.92	25,767.78
23	RT Spinning Reserve Cost Distribution Amount	24,314.05	25,309.90	17,066.59
24	RT Supplemental Reserve Cost Distribution Amount	1,498.98	19,949.36	10,292.90
25	RT Excessive Deficient Energy Deployment Charge Amount	28,392.67	20,018.03	24,891.66
26	RT Contingency Reserve Deployment Failure Charge Amount	1,328.18	-	-
27	RT Net Regulation Adjustment Amount	4,073.61	(95.76)	42.52
28	RT Ramp Capability Amount	(3,067.22)	(4,095.23)	(2,312.12)
29	RT Short-Tem Reserve Amount	(10,969.70)	(5,995.22)	(10,890.58)
30	Short-Term Reserve Cost Distribution Amount	54,911.01	163,387.11	137,736.53
31	Short-Term Reserve Deployment Failure Charge Amount			
32	FTR (Revenue) / Expenses	(405.96)	-	-
33	ARR (Revenue) / Expenses	178,618.30	178,618.30	178,618.30
34	Subtotal	(84,095.92)	(971,569.09)	(1,485,848.14)
35	Plus: Residual Load Adjustment Volume Changes			
36	Plus: MISO Charges (above) on sales billed to IMPA	-	-	-
37	Total (To BKA-2, Sch 5, line 23)	$ (84,095.92)	$ (971,569.09)	$ (1,485,848.14)

Negative amount is a credit to expense (payment from MISO)
Positive amount is a debit to expense (payment to MISO)

Cause No. 38708 FAC 149

Petitioner's Exhibit No. 1
Attachment FSB-1
CEI South
Schedule 2

CENTERPOINT ENERGY INDIANA SOUTH
Calculation of Daily Benchmark
Based on NYMEX Henry Hub Day Ahead Natural Gas Price

June 2025

Date	Day Ahead Cost $/MMBtu	Transportation $/MMBtu	Allowed Gas Price $/MMBtu	Heat Rate Btu/kWh	Daily Benchmark $/MWh
06/01/25	2.800	0.60	3.40	12,500	42.50
06/02/25	2.800	0.60	3.40	12,500	42.50
06/03/25	2.980	0.60	3.58	12,500	44.75
06/04/25	2.820	0.60	3.42	12,500	42.75
06/05/25	2.815	0.60	3.42	12,500	42.69
06/06/25	2.850	0.60	3.45	12,500	43.13
06/07/25	2.675	0.60	3.28	12,500	40.94
06/08/25	2.675	0.60	3.28	12,500	40.94
06/09/25	2.675	0.60	3.28	12,500	40.94
06/10/25	3.090	0.60	3.69	12,500	46.13
06/11/25	2.750	0.60	3.35	12,500	41.88
06/12/25	2.735	0.60	3.34	12,500	41.69
06/13/25	2.895	0.60	3.50	12,500	43.69
06/14/25	2.640	0.60	3.24	12,500	40.50
06/15/25	2.640	0.60	3.24	12,500	40.50
06/16/25	2.640	0.60	3.24	12,500	40.50
06/17/25	2.890	0.60	3.49	12,500	43.63
06/18/25	2.895	0.60	3.50	12,500	43.69
06/19/25	3.475	0.60	4.08	12,500	50.94
06/20/25	3.475	0.60	4.08	12,500	50.94
06/21/25	3.100	0.60	3.70	12,500	46.25
06/22/25	3.100	0.60	3.70	12,500	46.25
06/23/25	3.100	0.60	3.70	12,500	46.25
06/24/25	3.515	0.60	4.12	12,500	51.44
06/25/25	3.305	0.60	3.91	12,500	48.81
06/26/25	3.255	0.60	3.86	12,500	48.19
06/27/25	3.230	0.60	3.83	12,500	47.88
06/28/25	3.225	0.60	3.83	12,500	47.81
06/29/25	3.225	0.60	3.83	12,500	47.81
06/30/25	3.225	0.60	3.83	12,500	47.81

July 2025

Date	Day Ahead Cost $/MMBtu	Transportation $/MMBtu	Allowed Gas Price $/MMBtu	Heat Rate Btu/kWh	Daily Benchmark $/MWh
07/01/25	3.280	0.60	3.88 [4]	12,500	48.50
07/02/25	3.140	0.60	3.74	12,500	46.75
07/03/25	3.130	0.60	3.73	12,500	46.63
07/04/25	3.220	0.60	3.82	12,500	47.75
07/05/25	3.220	0.60	3.82	12,500	47.75
07/06/25	3.220	0.60	3.82	12,500	47.75
07/07/25	3.220	0.60	3.82	12,500	47.75
07/08/25	3.240	0.60	3.84	12,500	48.00
07/09/25	3.200	0.60	3.80	12,500	47.50
07/10/25	3.080	0.60	3.68	12,500	46.00
07/11/25	3.110	0.60	3.71	12,500	46.38
07/12/25	3.210	0.60	3.81	12,500	47.63
07/13/25	3.210	0.60	3.81	12,500	47.63
07/14/25	3.210	0.60	3.81	12,500	47.63
07/15/25	3.225	0.60	3.83	12,500	47.81
07/16/25	3.295	0.60	3.90	12,500	48.69
07/17/25	3.425	0.60	4.03	12,500	50.31
07/18/25	3.500	0.60	4.10	12,500	51.25
07/19/25	3.505	0.60	4.11	12,500	51.31
07/20/25	3.505	0.60	4.11	12,500	51.31
07/21/25	3.505	0.60	4.11	12,500	51.31
07/22/25	3.470	0.60	4.07	12,500	50.88
07/23/25	3.205	0.60	3.81	12,500	47.56
07/24/25	3.070	0.60	3.67	12,500	45.88
07/25/25	3.115	0.60	3.72	12,500	46.44
07/26/25	3.090	0.60	3.69	12,500	46.13
07/27/25	3.090	0.60	3.69	12,500	46.13
07/28/25	3.090	0.60	3.69	12,500	46.13
07/29/25	3.125	0.60	3.73	12,500	46.56
07/30/25	3.075	0.60	3.68	12,500	45.94
07/31/25	2.975	0.60	3.58	12,500	44.69

August 2025

Date	Day Ahead Cost $/MMBtu	Transportation $/MMBtu	Allowed Gas Price $/MMBtu	Heat Rate Btu/kWh	Daily Benchmark $/MWh
08/01/25	2.950	0.60	3.55 [4]	12,500	44.38
08/02/25	2.990	0.60	3.59	12,500	44.88
08/03/25	2.990	0.60	3.59	12,500	44.88
08/04/25	2.990	0.60	3.59	12,500	44.88
08/05/25	2.865	0.60	3.47	12,500	43.31
08/06/25	2.975	0.60	3.58	12,500	44.69
08/07/25	3.020	0.60	3.62	12,500	45.25
08/08/25	3.045	0.60	3.65	12,500	45.56
08/09/25	3.040	0.60	3.64	12,500	45.50
08/10/25	3.040	0.60	3.64	12,500	45.50
08/11/25	3.040	0.60	3.64	12,500	45.50
08/12/25	3.010	0.60	3.61	12,500	45.13
08/13/25	2.930	0.60	3.53	12,500	44.13
08/14/25	2.915	0.60	3.52	12,500	43.94
08/15/25	2.770	0.60	3.37	12,500	42.13
08/16/25	2.970	0.60	3.57	12,500	44.63
08/17/25	2.970	0.60	3.57	12,500	44.63
08/18/25	2.970	0.60	3.57	12,500	44.63
08/19/25	2.960	0.60	3.56	12,500	44.50
08/20/25	2.860	0.60	3.46	12,500	43.25
08/21/25	2.805	0.60	3.41	12,500	42.56
08/22/25	2.880	0.60	3.48	12,500	43.50
08/23/25	2.790	0.60	3.39	12,500	42.38
08/24/25	2.790	0.60	3.39	12,500	42.38
08/25/25	2.790	0.60	3.39	12,500	42.38
08/26/25	2.755	0.60	3.36	12,500	41.94
08/27/25	2.820	0.60	3.42	12,500	42.75
08/28/25	2.875	0.60	3.48	12,500	43.44
08/29/25	2.895	0.60	3.50	12,500	43.69
08/30/25	2.895	0.60	3.50	12,500	43.69
08/31/25	2.895	0.60	3.50	12,500	43.69

Total (To BKA-2, Sch 5, line 21)

CenterPoint Energy Indiana South
Market Settlements Group
Purchased Power Over Benchmark Explanations Cause No. 38708 FAC 149

S55's through 06/30

Jun Benchmark Costs	Trade Date	HE	Cost of Purchased Power	Purchases Volume	Price	Purchases Volume @ Benchmark $	Amount Over Benchmark $	Reason for Purchasing Power	Available Capacity of Units Not Selected	MISO Economic Dispatch / Purchased MWs above Capacity	Purchase Power Costs at Risk	Test for Outages and Derates: MWs Out of Service	11% of Summer Rated Capacity 791	Are Unit MWs Out of Service > 11% Summer Capacity?	Recoverable @ 0%, 85%, or 100%	MWs Subject to 85% 15%	Over Benchmark Price	Total Unrecoverable Dollars
42.50	06/01/2025	19	$ 12,046.33	239.520	$ 50.29	$ 10,179.60	$ 1,866.73	*Brown 3 Brown 4 and Culley 2 were on Reserve Shutdown*	330.145	-	$ -	12.000	87.01	NO	85	-	$ 7.79	$ -
42.50	06/01/2025	20	$ 8,661.13	168.800	$ 51.31	$ 7,174.00	$ 1,487.13		286.127	-	$ -	12.000	87.01	NO	85	-	$ 8.81	$ -
42.50	06/01/2025	21	$ 6,764.67	149.100	$ 45.37	$ 6,336.75	$ 427.92		302.000	-	$ -	12.000	87.01	NO	85	-	$ 2.87	$ -
42.50	06/02/2025	17	$ 4,258.60	99.500	$ 42.80	$ 4,228.75	$ 29.85	*Brown 3 Brown 4 and Culley 2 were on Reserve Shutdown*	376.737	-	$ -	12.000	87.01	NO	85	-	$ 0.30	$ -
42.50	06/02/2025	18	$ 6,468.80	136.300	$ 47.46	$ 5,792.75	$ 676.05		366.000	-	$ -	12.000	87.01	NO	85	-	$ 4.96	$ -
42.50	06/02/2025	19	$ 8,929.06	161.000	$ 55.46	$ 6,842.50	$ 2,086.56		344.000	-	$ -	12.000	87.01	NO	85	-	$ 12.96	$ -
42.50	06/02/2025	20	$ 12,630.60	233.900	$ 54.00	$ 9,940.75	$ 2,689.85		272.975	-	$ -	12.000	87.01	NO	85	-	$ 11.50	$ -
42.50	06/02/2025	21	$ 11,350.16	250.500	$ 45.31	$ 10,646.25	$ 703.91		260.938	-	$ -	12.000	87.01	NO	85	-	$ 2.81	$ -
44.75	06/03/2025	16	$ 6,313.44	136.330	$ 46.31	$ 6,100.77	$ 212.67	*Brown 3 Brown 4 and Brown 6 were on Outage*	75.441	60.89	$ 94.99	413.000	87.01	YES	100	-	$ 1.56	$ -
44.75	06/03/2025	17	$ 7,547.45	135.990	$ 55.50	$ 6,085.55	$ 1,461.90		31.850	104.14	$ 1,119.51	413.000	87.01	YES	100	-	$ 10.75	$ -
44.75	06/03/2025	18	$ 9,813.47	155.720	$ 63.02	$ 6,968.47	$ 2,845.00		24.425	131.30	$ 2,398.76	426.000	87.01	YES	100	-	$ 18.27	$ -
44.75	06/03/2025	19	$ 15,865.30	235.740	$ 67.30	$ 10,549.37	$ 5,315.94		0.625	235.12	$ 5,301.84	446.000	87.01	YES	100	-	$ 22.55	$ -
44.75	06/03/2025	20	$ 18,364.76	286.100	$ 64.19	$ 12,802.98	$ 5,561.79		5.454	280.65	$ 5,455.76	446.000	87.01	YES	100	-	$ 19.44	$ -
44.75	06/03/2025	21	$ 16,125.00	293.930	$ 54.86	$ 13,153.37	$ 2,971.63		6.398	287.53	$ 2,906.95	446.000	87.01	YES	100	-	$ 10.11	$ -
44.75	06/03/2025	22	$ 12,277.23	273.070	$ 44.96	$ 12,219.88	$ 57.35		17.583	255.49	$ 53.65	446.000	87.01	YES	100	-	$ 0.21	$ -
42.75	06/04/2025	19	$ 1,547.11	22.910	$ 67.53	$ 979.40	$ 567.71	*Brown 3 was on Reserve Shutdown all other units online*	77.000	-	$ -	19.000	87.01	NO	85	-	$ 24.78	$ -
42.75	06/04/2025	20	$ 3,196.25	48.590	$ 65.78	$ 2,077.22	$ 1,119.03		83.417	-	$ -	19.000	87.01	NO	85	-	$ 23.03	$ -
42.75	06/04/2025	21	$ 5,708.93	94.550	$ 60.38	$ 4,042.01	$ 1,666.92		92.833	1.72	$ 30.27	19.000	87.01	NO	85	1.72	$ 17.63	$ 4.54
42.75	06/04/2025	22	$ 8,392.62	164.400	$ 51.05	$ 7,028.10	$ 1,364.52		159.971	4.43	$ 36.76	19.000	87.01	NO	85	4.43	$ 8.30	$ 5.51
42.69	06/05/2025	6	$ 2,737.81	49.580	$ 55.22	$ 2,116.47	$ 621.34	*All units online load greater than generation*	146.625	-	$ -	59.000	87.01	NO	85	-	$ 12.53	$ -
42.69	06/05/2025	17	$ 3,492.02	79.800	$ 43.76	$ 3,406.50	$ 85.52		150.117	-	$ -	19.000	87.01	NO	85	-	$ 1.07	$ -
42.69	06/05/2025	18	$ 90.10	1.600	$ 56.31	$ 68.30	$ 21.80		76.183	-	$ -	19.000	87.01	NO	85	-	$ 13.62	$ -
42.69	06/05/2025	19	$ 2,072.86	34.200	$ 60.61	$ 1,459.93	$ 612.93		65.825	-	$ -	19.000	87.01	NO	85	-	$ 17.92	$ -
42.69	06/05/2025	20	$ 4,138.02	71.100	$ 58.20	$ 3,035.12	$ 1,102.90		94.892	-	$ -	19.000	87.01	NO	85	-	$ 15.51	$ -
42.69	06/05/2025	21	$ 5,957.52	114.700	$ 51.94	$ 4,896.31	$ 1,061.21		158.262	-	$ -	19.000	87.01	NO	85	-	$ 9.25	$ -
42.69	06/05/2025	22	$ 10,817.69	221.700	$ 48.79	$ 9,463.93	$ 1,353.76		191.137	30.56	$ 186.63	19.000	87.01	NO	85	30.56	$ 6.11	$ 27.99
42.69	06/05/2025	24	$ 4,685.97	77.840	$ 60.20	$ 3,322.83	$ 1,363.14		184.033	-	$ -	19.000	87.01	NO	85	-	$ 17.51	$ -
43.13	06/06/2025	8	$ 4,519.46	84.400	$ 53.55	$ 3,639.75	$ 879.71	*All units online load greater than generation*	173.875	-	$ -	25.000	87.01	NO	85	-	$ 10.42	$ -
43.13	06/06/2025	10	$ 6,142.80	119.500	$ 51.40	$ 5,153.44	$ 989.36		170.497	-	$ -	25.000	87.01	NO	85	-	$ 8.28	$ -
43.13	06/06/2025	12	$ 90.76	2.100	$ 43.22	$ 90.56	$ 0.20		169.475	-	$ -	25.000	87.01	NO	85	-	$ 0.09	$ -
43.13	06/06/2025	15	$ 2,448.01	51.200	$ 47.81	$ 2,208.00	$ 240.01		65.667	-	$ -	25.000	87.01	NO	85	-	$ 4.69	$ -
43.13	06/06/2025	16	$ 5,976.17	119.690	$ 49.93	$ 5,161.63	$ 814.54		65.825	53.87	$ 366.57	25.000	87.01	NO	85	53.87	$ 6.81	$ 54.99
43.13	06/06/2025	17	$ 3,128.90	64.500	$ 48.51	$ 2,781.56	$ 347.34		72.658	-	$ -	25.000	87.01	NO	85	-	$ 5.39	$ -
43.13	06/06/2025	18	$ 3,417.94	68.100	$ 50.19	$ 2,936.81	$ 481.13		79.563	-	$ -	25.000	87.01	NO	85	-	$ 7.07	$ -
43.13	06/06/2025	19	$ 4,101.92	83.700	$ 49.01	$ 3,609.56	$ 492.36		97.417	-	$ -	25.000	87.01	NO	85	-	$ 5.88	$ -
43.13	06/06/2025	20	$ 4,669.81	99.400	$ 46.98	$ 4,286.63	$ 383.19		129.517	-	$ -	25.000	87.01	NO	85	-	$ 3.85	$ -
43.13	06/06/2025	21	$ 4,638.10	103.900	$ 44.64	$ 4,480.69	$ 157.41		172.950	-	$ -	25.000	87.01	NO	85	-	$ 1.52	$ -
43.13	06/06/2025	22	$ 110.57	2.240	$ 49.36	$ 96.60	$ 13.97		179.917	-	$ -	25.000	87.01	NO	85	-	$ 6.24	$ -
40.94	06/07/2025	17	$ 4,727.13	109.780	$ 43.06	$ 4,494.17	$ 232.96	*Brown 3 and Culley 2 were on Reserve Shutdown*	212.250	-	$ -	27.000	87.01	NO	85	-	$ 2.12	$ -
40.94	06/07/2025	18	$ 5,509.15	119.660	$ 46.04	$ 4,898.64	$ 610.51		189.775	-	$ -	27.000	87.01	NO	85	-	$ 5.10	$ -
40.94	06/07/2025	19	$ 5,186.10	116.150	$ 44.65	$ 4,754.95	$ 431.15		188.208	-	$ -	27.000	87.01	NO	85	-	$ 3.71	$ -
40.94	06/07/2025	20	$ 7,386.08	172.250	$ 42.88	$ 7,051.57	$ 334.51		229.833	-	$ -	27.000	87.01	NO	85	-	$ 1.94	$ -
40.94	06/08/2025	19	$ 5,584.31	121.240	$ 46.06	$ 4,963.32	$ 620.99	*Brown 3 Brown 4 and Culley 2 were on Reserve Shutdown*	250.088	-	$ -	29.000	87.01	NO	85	-	$ 5.12	$ -
40.94	06/08/2025	20	$ 8,437.10	184.700	$ 45.68	$ 7,561.25	$ 875.85		245.583	-	$ -	29.000	87.01	NO	85	-	$ 4.74	$ -
40.94	06/08/2025	21	$ 8,830.50	210.300	$ 41.99	$ 8,609.26	$ 221.24		289.079	-	$ -	29.000	87.01	NO	85	-	$ 1.05	$ -
40.94	06/09/2025	19	$ 6,105.52	144.100	$ 42.37	$ 5,899.17	$ 206.35	*Brown 3 Brown 4 and Culley 2 were on Reserve Shutdown*	366.392	-	$ -	43.000	87.01	NO	85	-	$ 1.43	$ -
40.94	06/09/2025	20	$ 11,832.44	231.440	$ 51.13	$ 9,474.69	$ 2,357.75		322.117	-	$ -	43.000	87.01	NO	85	-	$ 10.19	$ -
40.94	06/09/2025	21	$ 9,275.31	173.500	$ 53.46	$ 7,102.74	$ 2,172.57		336.717	-	$ -	43.000	87.01	NO	85	-	$ 12.52	$ -
46.13	06/10/2025	19	$ 5,002.43	101.100	$ 49.48	$ 4,663.24	$ 339.19	*Brown 3 and Brown 4 were on Reserve Shutdown*	253.967	-	$ -	33.000	87.01	NO	85	-	$ 3.36	$ -
46.13	06/10/2025	20	$ 6,173.97	116.600	$ 52.95	$ 5,378.18	$ 795.80		222.862	-	$ -	33.000	87.01	NO	85	-	$ 6.83	$ -
41.88	06/11/2025	19	$ 1,696.38	35.480	$ 47.81	$ 1,485.73	$ 210.66	*Brown 3 was on Reserve Shutdown all other units online*	116.000	-	$ -	37.000	87.01	NO	85	-	$ 5.94	$ -
41.88	06/11/2025	20	$ 7,266.06	111.000	$ 65.46	$ 4,648.13	$ 2,617.94		133.208	-	$ -	37.000	87.01	NO	85	-	$ 23.59	$ -
41.88	06/11/2025	21	$ 8,597.47	162.800	$ 52.81	$ 6,817.25	$ 1,780.22		260.084	-	$ -	37.000	87.01	NO	85	-	$ 10.94	$ -
41.69	06/12/2025	13	$ 1,294.92	29.310	$ 44.18	$ 1,221.88	$ 73.04	*Brown 3 and Culley 2 were on Reserve Shutdown*	442.000	-	$ -	45.000	87.01	NO	85	-	$ 2.49	$ -
41.69	06/12/2025	14	$ 4,818.64	107.200	$ 44.95	$ 4,468.95	$ 349.69		344.884	-	$ -	45.000	87.01	NO	85	-	$ 3.26	$ -
41.69	06/12/2025	15	$ 7,263.02	135.580	$ 53.57	$ 5,652.06	$ 1,610.96		258.000	-	$ -	45.000	87.01	NO	85	-	$ 11.88	$ -
41.69	06/12/2025	16	$ 9,218.63	185.270	$ 49.76	$ 7,723.54	$ 1,495.09		232.331	-	$ -	45.000	87.01	NO	85	-	$ 8.07	$ -
41.69	06/12/2025	17	$ 14,039.54	232.120	$ 60.48	$ 9,676.62	$ 4,362.92		241.642	-	$ -	45.000	87.01	NO	85	-	$ 18.80	$ -
41.69	06/12/2025	18	$ 14,403.46	168.720	$ 85.37	$ 7,033.60	$ 7,369.86		162.208	6.51	$ 284.45	45.000	87.01	NO	85	6.51	$ 43.68	$ 42.67
41.69	06/12/2025	19	$ 8,400.67	129.700	$ 64.77	$ 5,406.93	$ 2,993.74		219.758	-	$ -	45.000	87.01	NO	85	-	$ 23.08	$ -
41.69	06/12/2025	20	$ 13,067.52	220.400	$ 59.29	$ 9,188.04	$ 3,879.48		303.200	-	$ -	45.000	87.01	NO	85	-	$ 17.60	$ -
41.69	06/12/2025	21	$ 14,059.15	274.700	$ 51.18	$ 11,451.69	$ 2,607.46		310.487	-	$ -	45.000	87.01	NO	85	-	$ 9.49	$ -

CenterPoint Energy Indiana South
Market Settlements Group
Purchased Power Over Benchmark Explanations Cause No. 38708 FAC 149

S55's through 06/30

Jun Benchmark Costs	Trade Date	HE	Cost of Purchased Power	Purchases Volume	Price	Purchases Volume @ Benchmark $	Amount Over Benchmark $	Reason for Purchasing Power	Available Capacity of Units Not Selected	MISO Economic Dispatch / Purchased MWs above Capacity	Purchase Power Costs at Risk	Test for Outages and Derates: MWs Out of Service	11% of Summer Rated Capacity	Are Unit MWs Out of Service > 11% Summer Capacity?	Recoverable @ 0%, 85%, or 100%	MWs Subject to 85% 15%	Over Benchmark Price	Total Unrecoverable Dollars
41.69	06/12/2025	23	$ 553.70	7.610	$ 72.76	$ 317.25	$ 236.45		472.000	-	$ -	45.000	87.01	NO	85	-	$ 31.07	$ -
43.69	06/13/2025	17	$ 16,439.73	355.300	$ 46.27	$ 15,522.35	$ 917.38	*Brown 3 Brown 4 Brown 6 and Culley 2 were on Reserve Shutdown*	458.000	-	$ -	43.000	87.01	NO	85	-	$ 2.58	$ -
40.50	06/14/2025	19	$ 14,666.12	333.700	$ 43.95	$ 13,514.85	$ 1,151.27	*Brown 3 Brown 4 Brown 6 and Culley 2 were on Reserve Shutdown*	452.483	-	$ -	49.000	87.01	NO	85	-	$ 3.45	$ -
40.50	06/14/2025	20	$ 15,848.52	381.800	$ 41.51	$ 15,462.90	$ 385.62		454.546	-	$ -	49.000	87.01	NO	85	-	$ 1.01	$ -
40.50	06/15/2025	17	$ 5,322.41	118.460	$ 44.93	$ 4,797.63	$ 524.78	*Brown 3 Brown 4 and Culley 2 were on Reserve Shutdown*	345.154	-	$ -	45.000	87.01	NO	85	-	$ 4.43	$ -
40.50	06/15/2025	18	$ 7,074.72	136.000	$ 52.02	$ 5,508.00	$ 1,566.72		382.154	-	$ -	45.000	87.01	NO	85	-	$ 11.52	$ -
40.50	06/15/2025	19	$ 9,268.97	166.200	$ 55.77	$ 6,731.10	$ 2,537.87		369.258	-	$ -	45.000	87.01	NO	85	-	$ 15.27	$ -
40.50	06/15/2025	20	$ 12,383.35	215.400	$ 57.49	$ 8,723.70	$ 3,659.65		356.833	-	$ -	45.000	87.01	NO	85	-	$ 16.99	$ -
40.50	06/15/2025	21	$ 10,486.15	200.500	$ 52.30	$ 8,120.25	$ 2,365.90		337.350	-	$ -	45.000	87.01	NO	85	-	$ 11.80	$ -
40.50	06/15/2025	22	$ 11,239.54	251.500	$ 44.69	$ 10,185.75	$ 1,053.79		372.292	-	$ -	45.000	87.01	NO	85	-	$ 4.19	$ -
40.50	06/16/2025	14	$ 2,805.22	69.060	$ 40.62	$ 2,796.93	$ 8.29	*Brown 3 Brown 4 and Culley 2 were on Reserve Shutdown*	449.000	-	$ -	52.000	87.01	NO	85	-	$ 0.12	$ -
40.50	06/16/2025	15	$ 14,256.41	339.600	$ 41.98	$ 13,753.80	$ 502.61		434.000	-	$ -	52.000	87.01	NO	85	-	$ 1.48	$ -
40.50	06/16/2025	16	$ 13,697.55	262.950	$ 52.09	$ 10,649.48	$ 3,048.08		251.000	11.95	$ 138.52	52.000	87.01	NO	85	11.95	$ 11.59	$ 20.78
40.50	06/16/2025	17	$ 7,372.47	144.700	$ 50.95	$ 5,860.35	$ 1,512.12		305.917	-	$ -	52.000	87.01	NO	85	-	$ 10.45	$ -
40.50	06/16/2025	18	$ 9,010.50	165.300	$ 54.51	$ 6,694.65	$ 2,315.85		302.917	-	$ -	52.000	87.01	NO	85	-	$ 14.01	$ -
40.50	06/16/2025	19	$ 14,235.00	266.070	$ 53.50	$ 10,775.84	$ 3,459.17		250.308	15.76	$ 204.92	52.000	87.01	NO	85	15.76	$ 13.00	$ 30.74
40.50	06/16/2025	20	$ 17,315.18	289.600	$ 59.79	$ 11,728.80	$ 5,586.38		306.775	-	$ -	52.000	87.01	NO	85	-	$ 19.29	$ -
40.50	06/16/2025	21	$ 13,192.79	258.530	$ 51.03	$ 10,470.47	$ 2,722.33		289.604	-	$ -	52.000	87.01	NO	85	-	$ 10.53	$ -
43.63	06/17/2025	13	$ 339.38	7.300	$ 46.49	$ 318.46	$ 20.92	*All units online load greater than generation*	165.133	-	$ -	33.000	87.01	NO	85	-	$ 2.87	$ -
43.63	06/17/2025	16	$ 126.42	2.100	$ 60.20	$ 91.61	$ 34.81		98.817	-	$ -	54.000	87.01	NO	85	-	$ 16.58	$ -
43.63	06/17/2025	18	$ 291.99	6.370	$ 45.84	$ 277.89	$ 14.10		86.754	-	$ -	66.000	87.01	NO	85	-	$ 2.21	$ -
43.63	06/17/2025	19	$ 4,118.37	12.070	$ 341.21	$ 526.55	$ 3,591.82		49.537	-	$ -	66.000	87.01	NO	85	-	$ 297.58	$ -
43.63	06/17/2025	20	$ 8,538.66	117.340	$ 72.77	$ 5,118.96	$ 3,419.70		76.908	40.43	$ 1,178.33	66.000	87.01	NO	85	40.43	$ 29.14	$ 176.75
43.63	06/17/2025	21	$ 13,497.20	102.910	$ 131.16	$ 4,489.45	$ 9,007.75		62.909	40.00	$ 3,501.30	66.000	87.01	NO	85	40.00	$ 87.53	$ 525.20
43.63	06/17/2025	22	$ 5,331.88	96.400	$ 55.31	$ 4,205.45	$ 1,126.43		81.254	15.15	$ 176.98	66.000	87.01	NO	85	15.15	$ 11.68	$ 26.55
43.63	06/17/2025	23	$ 644.44	13.040	$ 49.42	$ 568.87	$ 75.57		231.175	-	$ -	66.000	87.01	NO	85	-	$ 5.80	$ -
43.69	06/18/2025	6	$ 1,081.19	6.020	$ 179.60	$ 263.00	$ 818.19	*Culley 3 was on outage all other units online*	374.167	-	$ -	321.000	87.01	YES	100	-	$ 135.91	$ -
43.69	06/18/2025	7	$ 219.79	1.090	$ 201.64	$ 47.62	$ 172.17		375.083	-	$ -	321.000	87.01	YES	100	-	$ 157.95	$ -
43.69	06/18/2025	13	$ 3,105.47	69.420	$ 44.73	$ 3,032.82	$ 72.65		165.724	-	$ -	321.000	87.01	YES	100	-	$ 1.05	$ -
43.69	06/18/2025	14	$ 12,465.16	279.300	$ 44.63	$ 12,202.06	$ 263.10		140.221	139.08	$ 131.01	321.000	87.01	YES	100	-	$ 0.94	$ -
43.69	06/18/2025	15	$ 16,905.13	359.720	$ 47.00	$ 15,715.45	$ 1,189.68		114.075	245.65	$ 812.41	321.000	87.01	YES	100	-	$ 3.31	$ -
43.69	06/18/2025	16	$ 15,354.64	305.140	$ 50.32	$ 13,330.96	$ 2,023.68		125.119	180.02	$ 1,193.90	321.000	87.01	YES	100	-	$ 6.63	$ -
43.69	06/18/2025	17	$ 13,201.00	248.700	$ 53.08	$ 10,865.21	$ 2,335.79		141.625	107.08	$ 1,005.65	321.000	87.01	YES	100	-	$ 9.39	$ -
43.69	06/18/2025	18	$ 15,893.83	298.700	$ 53.21	$ 13,049.61	$ 2,844.22		140.833	157.87	$ 1,503.21	326.000	87.01	YES	100	-	$ 9.52	$ -
43.69	06/18/2025	19	$ 17,963.25	308.700	$ 58.19	$ 13,486.49	$ 4,476.76		144.558	164.14	$ 2,380.39	326.000	87.01	YES	100	-	$ 14.50	$ -
43.69	06/18/2025	20	$ 19,377.40	346.520	$ 55.92	$ 15,138.77	$ 4,238.63		112.621	233.90	$ 2,861.05	326.000	87.01	YES	100	-	$ 12.23	$ -
43.69	06/18/2025	21	$ 19,147.44	361.000	$ 53.04	$ 15,771.37	$ 3,376.07		125.208	235.79	$ 2,205.13	326.000	87.01	YES	100	-	$ 9.35	$ -
50.94	06/19/2025	17	$ 14,877.24	268.300	$ 55.45	$ 13,666.67	$ 1,210.57	*Culley 3 was on outage all other units online*	182.867	85.43	$ 385.48	325.000	87.01	YES	100	-	$ 4.51	$ -
50.94	06/19/2025	18	$ 16,346.87	280.200	$ 58.34	$ 14,272.83	$ 2,074.04		157.075	123.13	$ 911.37	325.000	87.01	YES	100	-	$ 7.40	$ -
50.94	06/19/2025	19	$ 18,543.00	262.500	$ 70.64	$ 13,371.23	$ 5,171.78		101.534	160.97	$ 3,171.35	325.000	87.01	YES	100	-	$ 19.70	$ -
50.94	06/19/2025	20	$ 21,602.16	328.500	$ 65.76	$ 16,733.13	$ 4,869.03		84.291	244.21	$ 3,619.67	325.000	87.01	YES	100	-	$ 14.82	$ -
50.94	06/19/2025	21	$ 19,937.57	368.600	$ 54.09	$ 18,775.75	$ 1,161.82		171.983	196.62	$ 619.73	325.000	87.01	YES	100	-	$ 3.15	$ -
50.94	06/20/2025	17	$ 36,912.81	669.560	$ 55.13	$ 34,106.05	$ 2,806.76	*Culley 3 was on outage Culley 2 Brown 3 Brown 4 and Brown 6 were on Reserve Shutdown*	440.000	229.56	$ 962.30	321.000	87.01	YES	100	-	$ 4.19	$ -
50.94	06/20/2025	18	$ 36,624.41	676.660	$ 54.13	$ 34,467.71	$ 2,156.70		440.000	236.66	$ 754.30	321.000	87.01	YES	100	-	$ 3.19	$ -
50.94	06/20/2025	19	$ 33,277.92	635.560	$ 52.36	$ 32,374.16	$ 903.76		440.000	195.56	$ 278.09	321.000	87.01	YES	100	-	$ 1.42	$ -
46.25	06/21/2025	11	$ 967.45	16.060	$ 60.24	$ 742.78	$ 224.68	*Culley 2 was on Reserve Shutdown and Culley 3 was on outage*	448.000	-	$ -	313.000	87.01	YES	100	-	$ 13.99	$ -
46.25	06/21/2025	12	$ 1,754.45	16.860	$ 104.06	$ 779.78	$ 974.68		448.000	-	$ -	313.000	87.01	YES	100	-	$ 57.81	$ -
46.25	06/21/2025	13	$ 2,859.20	35.860	$ 79.73	$ 1,658.53	$ 1,200.68		448.000	-	$ -	313.000	87.01	YES	100	-	$ 33.48	$ -
46.25	06/21/2025	14	$ 6,180.18	54.660	$ 113.07	$ 2,528.03	$ 3,652.16		448.000	-	$ -	313.000	87.01	YES	100	-	$ 66.82	$ -
46.25	06/21/2025	17	$ 11,786.72	248.560	$ 47.42	$ 11,495.90	$ 290.82		89.950	158.61	$ 185.58	313.000	87.01	YES	100	-	$ 1.17	$ -
46.25	06/21/2025	18	$ 17,722.24	318.860	$ 55.58	$ 14,747.28	$ 2,974.97		150.417	168.44	$ 1,571.57	313.000	87.01	YES	100	-	$ 9.33	$ -
46.25	06/21/2025	19	$ 23,300.08	398.360	$ 58.49	$ 18,424.15	$ 4,875.93		167.832	230.53	$ 2,821.66	313.000	87.01	YES	100	-	$ 12.24	$ -
46.25	06/21/2025	20	$ 26,233.41	410.860	$ 63.85	$ 19,002.28	$ 7,231.14		97.000	313.86	$ 5,523.94	313.000	87.01	YES	100	0.86	$ 17.60	$ 2.27
46.25	06/21/2025	21	$ 24,910.33	484.260	$ 51.44	$ 22,397.03	$ 2,513.31		157.890	326.37	$ 1,693.86	313.000	87.01	YES	100	13.37	$ 5.19	$ 10.41
46.25	06/22/2025	14	$ 11,519.46	240.540	$ 47.89	$ 11,124.98	$ 394.49	*Culley 3 was on outage all other units online*	58.819	181.72	$ 298.02	314.000	87.01	YES	100	-	$ 1.64	$ -
46.25	06/22/2025	15	$ 13,952.56	253.960	$ 54.94	$ 11,745.65	$ 2,206.91		66.000	187.96	$ 1,633.37	314.000	87.01	YES	100	-	$ 8.69	$ -
46.25	06/22/2025	16	$ 17,005.37	275.060	$ 61.82	$ 12,721.53	$ 4,283.85		66.108	208.95	$ 3,254.26	314.000	87.01	YES	100	-	$ 15.57	$ -
46.25	06/22/2025	17	$ 19,495.89	242.150	$ 80.51	$ 11,199.44	$ 8,296.45		15.338	226.81	$ 7,770.95	314.000	87.01	YES	100	-	$ 34.26	$ -
46.25	06/22/2025	18	$ 26,412.49	261.160	$ 101.14	$ 12,078.65	$ 14,333.84		3.106	258.05	$ 14,163.37	314.000	87.01	YES	100	-	$ 54.89	$ -
46.25	06/22/2025	19	$ 44,803.58	334.090	$ 134.11	$ 15,451.66	$ 29,351.92		18.292	315.80	$ 27,744.85	314.000	87.01	YES	100	1.80	$ 87.86	$ 23.69
46.25	06/22/2025	20	$ 49,466.51	408.970	$ 120.95	$ 18,914.86	$ 30,551.65		5.424	403.55	$ 30,146.45	314.000	87.01	YES	100	89.55	$ 74.70	$ 1,003.42
46.25	06/22/2025	21	$ 31,158.95	419.280	$ 74.32	$ 19,391.70	$ 11,767.25		17.333	401.95	$ 11,280.79	314.000	87.01	YES	100	87.95	$ 28.07	$ 370.24

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Purchased Power Over Benchmark Explanations Cause No. 38708 FAC 149

S55's through 06/30

Jun Benchmark Costs	Trade Date	HE	Cost of Purchased Power	Purchases Volume	Price	Purchases Volume @ Benchmark $	Amount Over Benchmark $	Reason for Purchasing Power	Available Capacity of Units Not Selected	MISO Economic Dispatch / Purchased MWs above Capacity	Purchase Power Costs at Risk	Test for Outages and Derates: MWs Out of Service	11% of Summer Rated Capacity	Are Unit MWs Out of Service > 11% Summer Capacity?	Recoverable @ 0%, 85%, or 100%	MWs Subject to 85% 15%	Over Benchmark Price	Total Unrecoverable Dollars
46.25	06/22/2025	22	$ 23,627.02	421.610	$ 56.04	$ 19,499.46	$ 4,127.56		76.942	344.67	$ 3,374.30	314.000	87.01	YES	100	30.67	$ 9.79	$ 45.04
46.25	06/23/2025	9	$ 22,273.64	455.680	$ 48.88	$ 21,075.20	$ 1,198.44		353.208	102.47	$ 269.50	314.000	87.01	YES	100	-	$ 2.63	$ -
46.25	06/23/2025	10	$ 16,455.98	294.910	$ 55.80	$ 13,639.59	$ 2,816.39		184.542	110.37	$ 1,054.02	314.000	87.01	YES	100	-	$ 9.55	$ -
46.25	06/23/2025	11	$ 17,140.84	257.370	$ 66.60	$ 11,903.36	$ 5,237.48		103.783	153.59	$ 3,125.49	314.000	87.01	YES	100	-	$ 20.35	$ -
46.25	06/23/2025	12	$ 22,772.50	234.970	$ 96.92	$ 10,867.36	$ 11,905.14		28.767	206.20	$ 10,447.61	314.000	87.01	YES	100	-	$ 50.67	$ -
46.25	06/23/2025	13	$ 28,626.38	241.300	$ 118.63	$ 11,160.13	$ 17,466.26		0.000	241.30	$ 17,466.26	287.000	87.01	YES	100	-	$ 72.38	$ -
46.25	06/23/2025	14	$ 34,957.54	252.290	$ 138.56	$ 11,668.41	$ 23,289.13		0.067	252.22	$ 23,282.94	287.000	87.01	YES	100	-	$ 92.31	$ -
46.25	06/23/2025	15	$ 47,465.84	296.220	$ 160.24	$ 13,700.18	$ 33,765.67		16.000	280.22	$ 31,941.85	287.000	87.01	YES	100	-	$ 113.99	$ -
46.25	06/23/2025	16	$ 58,213.08	258.640	$ 225.07	$ 11,962.10	$ 46,250.98	*Culley 3 was on outage all other units online*	3.234	255.41	$ 45,672.66	287.000	87.01	YES	100	-	$ 178.82	$ -
46.25	06/23/2025	17	$ 71,408.02	270.690	$ 263.80	$ 12,519.41	$ 58,888.61		1.971	268.72	$ 58,459.82	287.000	87.01	YES	100	-	$ 217.55	$ -
46.25	06/23/2025	18	$ 77,069.97	282.380	$ 272.93	$ 13,060.08	$ 64,009.90		3.550	278.83	$ 63,205.18	282.000	87.01	YES	100	-	$ 226.68	$ -
46.25	06/23/2025	19	$ 93,526.86	318.780	$ 293.39	$ 14,743.58	$ 78,783.29		0.625	318.16	$ 78,628.82	282.000	87.01	YES	100	36.16	$ 247.14	$ 1,340.30
46.25	06/23/2025	20	$ 120,796.68	405.290	$ 298.05	$ 18,744.66	$ 102,052.02		0.000	405.29	$ 102,052.02	283.000	87.01	YES	100	122.29	$ 251.80	$ 4,618.89
46.25	06/23/2025	21	$ 107,832.39	426.450	$ 252.86	$ 19,723.31	$ 88,109.08		4.750	421.70	$ 87,127.68	302.000	87.01	YES	100	119.70	$ 206.61	$ 3,709.69
46.25	06/23/2025	22	$ 80,231.68	474.620	$ 169.04	$ 21,951.18	$ 58,280.51		72.558	402.06	$ 49,370.82	304.000	87.01	YES	100	98.06	$ 122.79	$ 1,806.21
46.25	06/23/2025	23	$ 42,702.86	423.010	$ 100.95	$ 19,564.21	$ 23,138.65		74.209	348.80	$ 19,079.42	308.000	87.01	YES	100	40.80	$ 54.70	$ 334.77
46.25	06/23/2025	24	$ 28,322.35	409.460	$ 69.17	$ 18,937.53	$ 9,384.83		123.216	286.24	$ 6,560.71	308.000	87.01	YES	100	-	$ 22.92	$ -
51.44	06/24/2025	1	$ 23,999.89	358.850	$ 66.88	$ 18,458.53	$ 5,541.36		154.005	204.85	$ 3,163.22	302.000	87.01	YES	100	-	$ 15.44	$ -
51.44	06/24/2025	7	$ 16,877.33	276.270	$ 61.09	$ 14,210.78	$ 2,666.55		161.771	114.50	$ 1,105.14	302.000	87.01	YES	100	-	$ 9.65	$ -
51.44	06/24/2025	8	$ 13,977.08	216.330	$ 64.61	$ 11,127.58	$ 2,849.50		128.205	88.13	$ 1,160.78	302.000	87.01	YES	100	-	$ 13.17	$ -
51.44	06/24/2025	9	$ 13,003.77	187.780	$ 69.25	$ 9,659.03	$ 3,344.74		100.346	87.43	$ 1,557.38	302.000	87.01	YES	100	-	$ 17.81	$ -
51.44	06/24/2025	10	$ 15,288.02	202.760	$ 75.40	$ 10,429.57	$ 4,858.45		72.171	130.59	$ 3,129.12	302.000	87.01	YES	100	-	$ 23.96	$ -
51.44	06/24/2025	11	$ 14,777.79	155.180	$ 95.23	$ 7,982.15	$ 6,795.64		7.071	148.11	$ 6,485.99	302.000	87.01	YES	100	-	$ 43.79	$ -
51.44	06/24/2025	12	$ 24,404.55	187.850	$ 129.92	$ 9,662.63	$ 14,741.92		0.000	187.85	$ 14,741.92	302.000	87.01	YES	100	-	$ 78.48	$ -
51.44	06/24/2025	13	$ 42,708.38	226.020	$ 188.96	$ 11,626.02	$ 31,082.36		0.000	226.02	$ 31,082.36	281.000	87.01	YES	100	-	$ 137.52	$ -
51.44	06/24/2025	14	$ 49,881.26	261.320	$ 190.88	$ 13,441.78	$ 36,439.48		0.000	261.32	$ 36,439.48	281.000	87.01	YES	100	-	$ 139.44	$ -
51.44	06/24/2025	15	$ 54,867.37	283.240	$ 193.71	$ 14,569.30	$ 40,298.07	*Culley 3 was on outage all other units online*	0.000	283.24	$ 40,298.07	281.000	87.01	YES	100	2.24	$ 142.28	$ 47.80
51.44	06/24/2025	16	$ 90,702.02	365.940	$ 247.86	$ 18,823.22	$ 71,878.80		0.000	365.94	$ 71,878.80	281.000	87.01	YES	100	84.94	$ 196.42	$ 2,502.62
51.44	06/24/2025	17	$ 126,785.23	409.210	$ 309.83	$ 21,048.94	$ 105,736.29		0.000	409.21	$ 105,736.29	280.000	87.01	YES	100	129.21	$ 258.39	$ 5,008.01
51.44	06/24/2025	18	$ 113,275.24	361.590	$ 313.27	$ 18,599.47	$ 94,675.77		10.417	351.17	$ 91,948.27	280.000	87.01	YES	100	71.17	$ 261.83	$ 2,795.30
51.44	06/24/2025	19	$ 121,062.44	349.680	$ 346.21	$ 17,986.84	$ 103,075.60		10.000	339.68	$ 100,127.89	281.000	87.01	YES	100	58.68	$ 294.77	$ 2,594.58
51.44	06/24/2025	20	$ 100,687.16	350.460	$ 287.30	$ 18,026.96	$ 82,660.20		0.000	350.46	$ 82,660.20	279.000	87.01	YES	100	71.46	$ 235.86	$ 2,528.20
51.44	06/24/2025	21	$ 71,901.80	371.970	$ 193.30	$ 19,133.39	$ 52,768.41		4.000	367.97	$ 52,200.96	301.000	87.01	YES	100	66.97	$ 141.86	$ 1,425.07
51.44	06/24/2025	22	$ 50,246.94	427.910	$ 117.42	$ 22,010.83	$ 28,236.11		84.100	343.81	$ 22,686.68	302.000	87.01	YES	100	41.81	$ 65.99	$ 413.83
51.44	06/24/2025	23	$ 31,446.02	390.510	$ 80.53	$ 20,087.05	$ 11,358.97		109.408	281.10	$ 8,176.56	302.000	87.01	YES	100	-	$ 29.09	$ -
51.44	06/24/2025	24	$ 22,253.32	375.520	$ 59.26	$ 19,316.00	$ 2,937.32		145.539	229.98	$ 1,798.91	302.000	87.01	YES	100	-	$ 7.82	$ -
48.81	06/25/2025	1	$ 23,886.29	448.570	$ 53.25	$ 21,896.05	$ 1,990.24		245.498	203.07	$ 901.00	304.000	87.01	YES	100	-	$ 4.44	$ -
48.81	06/25/2025	7	$ 19,985.66	392.800	$ 50.88	$ 19,173.75	$ 811.91		256.292	136.51	$ 282.16	304.000	87.01	YES	100	-	$ 2.07	$ -
48.81	06/25/2025	8	$ 15,998.06	310.100	$ 51.59	$ 15,136.91	$ 861.15		232.245	77.86	$ 216.20	304.000	87.01	YES	100	-	$ 2.78	$ -
48.81	06/25/2025	9	$ 15,338.75	274.200	$ 55.94	$ 13,384.52	$ 1,954.23		248.862	25.34	$ 180.58	304.000	87.01	YES	100	-	$ 7.13	$ -
48.81	06/25/2025	10	$ 16,290.68	292.000	$ 55.79	$ 14,253.40	$ 2,037.28		202.000	90.00	$ 627.93	304.000	87.01	YES	100	-	$ 6.98	$ -
48.81	06/25/2025	11	$ 23,635.03	329.500	$ 71.73	$ 16,083.88	$ 7,551.15		91.943	237.56	$ 5,444.09	304.000	87.01	YES	100	-	$ 22.92	$ -
48.81	06/25/2025	12	$ 19,841.88	259.100	$ 76.58	$ 12,647.45	$ 7,194.43		86.254	172.85	$ 4,799.42	304.000	87.01	YES	100	-	$ 27.77	$ -
48.81	06/25/2025	13	$ 38,849.41	350.860	$ 110.73	$ 17,126.53	$ 21,722.88		13.916	336.94	$ 20,861.30	283.000	87.01	YES	100	53.94	$ 61.91	$ 500.98
48.81	06/25/2025	14	$ 38,501.08	349.790	$ 110.07	$ 17,074.30	$ 21,426.78	*Culley 3 was on outage all other units online*	1.013	348.78	$ 21,364.73	283.000	87.01	YES	100	65.78	$ 61.26	$ 604.39
48.81	06/25/2025	15	$ 41,419.76	412.400	$ 100.44	$ 20,130.48	$ 21,289.28		11.000	401.40	$ 20,721.43	283.000	87.01	YES	100	118.40	$ 51.62	$ 916.82
48.81	06/25/2025	16	$ 40,715.76	389.700	$ 104.48	$ 19,022.43	$ 21,693.33		8.000	381.70	$ 21,248.00	283.000	87.01	YES	100	98.70	$ 55.67	$ 824.15
48.81	06/25/2025	17	$ 67,927.35	440.060	$ 154.36	$ 21,480.65	$ 46,446.70		0.000	440.06	$ 46,446.70	283.000	87.01	YES	100	157.06	$ 105.55	$ 2,486.57
48.81	06/25/2025	18	$ 68,933.08	426.120	$ 161.77	$ 20,800.20	$ 48,132.88		0.000	426.12	$ 48,132.88	283.000	87.01	YES	100	143.12	$ 112.96	$ 2,424.94
48.81	06/25/2025	19	$ 65,341.80	439.740	$ 148.59	$ 21,465.03	$ 43,876.77		1.746	437.99	$ 43,702.56	283.000	87.01	YES	100	154.99	$ 99.78	$ 2,319.77
48.81	06/25/2025	20	$ 65,116.89	509.510	$ 127.80	$ 24,870.71	$ 40,246.18		6.000	503.51	$ 39,772.24	283.000	87.01	YES	100	220.51	$ 78.99	$ 2,612.71
48.81	06/25/2025	21	$ 47,234.72	520.350	$ 90.77	$ 25,399.84	$ 21,834.88		23.388	496.96	$ 20,853.47	304.000	87.01	YES	100	192.96	$ 41.96	$ 1,214.56
48.81	06/25/2025	22	$ 38,831.13	547.730	$ 70.89	$ 26,736.34	$ 12,094.79		89.096	458.63	$ 10,127.40	304.000	87.01	YES	100	154.63	$ 22.08	$ 512.19
48.81	06/25/2025	23	$ 30,881.70	564.170	$ 54.74	$ 27,538.83	$ 3,342.87		174.021	390.15	$ 2,311.75	304.000	87.01	YES	100	86.15	$ 5.93	$ 76.57
48.19	06/26/2025	7	$ 29,334.81	601.000	$ 48.81	$ 28,960.99	$ 373.82		367.000	234.00	$ 145.55	304.000	87.01	YES	100	-	$ 0.62	$ -
48.19	06/26/2025	8	$ 26,362.02	524.200	$ 50.29	$ 25,260.15	$ 1,101.87		345.000	179.20	$ 376.68	304.000	87.01	YES	100	-	$ 2.10	$ -
48.19	06/26/2025	9	$ 15,541.64	295.300	$ 52.63	$ 14,229.92	$ 1,311.72		212.271	83.03	$ 368.82	304.000	87.01	YES	100	-	$ 4.44	$ -
48.19	06/26/2025	10	$ 18,352.16	323.500	$ 56.73	$ 15,588.82	$ 2,763.34		192.417	131.08	$ 1,119.71	304.000	87.01	YES	100	-	$ 8.54	$ -
48.19	06/26/2025	11	$ 19,067.02	291.500	$ 65.41	$ 14,046.80	$ 5,020.22		153.242	138.26	$ 2,381.08	304.000	87.01	YES	100	-	$ 17.22	$ -
48.19	06/26/2025	12	$ 28,783.39	362.050	$ 79.50	$ 17,446.47	$ 11,336.92		107.000	255.05	$ 7,986.42	304.000	87.01	YES	100	-	$ 31.31	$ -
48.19	06/26/2025	13	$ 35,850.88	371.820	$ 96.42	$ 17,917.26	$ 17,933.62		55.000	316.82	$ 15,280.86	283.000	87.01	YES	100	33.82	$ 48.23	$ 244.68
48.19	06/26/2025	14	$ 43,179.27	390.930	$ 110.45	$ 18,838.13	$ 24,341.14		56.000	334.93	$ 20,854.31	283.000	87.01	YES	100	51.93	$ 62.26	$ 485.01
48.19	06/26/2025	15	$ 40,188.20	336.500	$ 119.43	$ 16,215.26	$ 23,972.94	*Culley 3 was on outage all other units online*	55.000	281.50	$ 20,054.63	283.000	87.01	YES	100	-	$ 71.24	$ -
48.19	06/26/2025	16	$ 36,749.36	298.000	$ 123.32	$ 14,360.02	$ 22,389.34		56.000	242.00	$ 18,181.94	283.000	87.01	YES	100	-	$ 75.13	$ -
48.19	06/26/2025	17	$ 48,744.38	344.800	$ 141.37	$ 16,615.22	$ 32,129.16		54.000	290.80	$ 27,097.33	283.000	87.01	YES	100	7.80	$ 93.18	$ 109.02
48.19	06/26/2025	18	$ 47,265.36	320.900	$ 147.29	$ 15,463.53	$ 31,801.83		56.000	264.90	$ 26,252.12	283.000	87.01	YES	100	-	$ 99.10	$ -
48.19	06/26/2025	19	$ 76,596.98	485.900	$ 157.64	$ 23,414.55	$ 53,182.43		56.000	429.90	$ 47,053.15	283.000	87.01	YES	100	146.90	$ 109.45	$ 2,411.76
48.19	06/26/2025	20	$ 84,387.29	538.380	$ 156.74	$ 25,943.46	$ 58,443.83		55.000	483.38	$ 52,473.31	283.000	87.01	YES	100	200.38	$ 108.55	$ 3,262.84
48.19	06/26/2025	21	$ 54,822.62	444.700	$ 123.28	$ 21,429.20	$ 33,393.42		146.317	298.38	$ 22,406.18	304.000	87.01	YES	100	-	$ 75.09	$ -
48.19	06/26/2025	22	$ 36,176.60	464.100	$ 77.95	$ 22,364.05	$ 13,812.55		140.867	323.23	$ 9,620.06	304.000	87.01	YES	100	19.23	$ 29.76	$ 85.86

CenterPoint Energy Indiana South
Market Settlements Group
Purchased Power Over Benchmark Explanations Cause No. 38708 FAC 149

S55's through 06/30

Jun Benchmark Costs	Trade Date	HE	Cost of Purchased Power	Purchases Volume	Price	Purchases Volume @ Benchmark $	Amount Over Benchmark $	Reason for Purchasing Power	Available Capacity of Units Not Selected	MISO Economic Dispatch / Purchased MWs above Capacity	Purchase Power Costs at Risk	Test for Outages and Derates: MWs Out of Service	11% of Summer Rated Capacity	Are Unit MWs Out of Service > 11% Summer Capacity?	Recoverable @ 0%, 85%, or 100%	MWs Subject to 85% 15%	Over Benchmark Price	Total Unrecoverable Dollars
48.19	06/26/2025	23	$ 28,897.10	509.200	$ 56.75	$ 24,537.33	$ 4,359.77		257.267	251.93	$ 2,157.05	304.000	87.01	YES	100	-	$ 8.56	$ -
48.19	06/26/2025	24	$ 23,784.99	486.500	$ 48.89	$ 23,443.46	$ 341.53		267.517	218.98	$ 153.73	304.000	87.01	YES	100	-	$ 0.70	$ -
47.88	06/27/2025	11	$ 20,489.21	379.500	$ 53.99	$ 18,168.56	$ 2,320.65		248.987	130.51	$ 798.09	304.000	87.01	YES	100	-	$ 6.12	$ -
47.88	06/27/2025	12	$ 25,118.62	423.300	$ 59.34	$ 20,265.49	$ 4,853.13		216.930	206.37	$ 2,366.03	304.000	87.01	YES	100	-	$ 11.46	$ -
47.88	06/27/2025	13	$ 22,049.94	321.100	$ 68.67	$ 15,372.66	$ 6,677.28		86.000	235.10	$ 4,888.91	283.000	87.01	YES	100	-	$ 20.80	$ -
47.88	06/27/2025	14	$ 22,753.62	298.800	$ 76.15	$ 14,305.05	$ 8,448.57		56.000	242.80	$ 6,865.17	283.000	87.01	YES	100	-	$ 28.28	$ -
47.88	06/27/2025	15	$ 30,279.26	404.140	$ 74.92	$ 19,348.20	$ 10,931.06		55.000	349.14	$ 9,443.43	283.000	87.01	YES	100	66.14	$ 27.05	$ 268.34
47.88	06/27/2025	16	$ 30,978.56	429.670	$ 72.10	$ 20,570.45	$ 10,408.11	*Culley 3 was on outage all other units*	55.000	374.67	$ 9,075.82	283.000	87.01	YES	100	91.67	$ 24.22	$ 333.09
47.88	06/27/2025	17	$ 28,004.79	331.300	$ 84.53	$ 15,860.99	$ 12,143.80	*online*	56.000	275.30	$ 10,091.12	283.000	87.01	YES	100	-	$ 36.66	$ -
47.88	06/27/2025	18	$ 27,314.78	328.500	$ 83.15	$ 15,726.94	$ 11,587.84		55.000	273.50	$ 9,647.72	283.000	87.01	YES	100	-	$ 35.28	$ -
47.88	06/27/2025	19	$ 33,826.12	363.800	$ 92.98	$ 17,416.93	$ 16,409.20		55.000	308.80	$ 13,928.42	283.000	87.01	YES	100	25.80	$ 45.10	$ 174.56
47.88	06/27/2025	20	$ 36,950.34	468.200	$ 78.92	$ 22,415.08	$ 14,535.27		55.000	413.20	$ 12,827.79	283.000	87.01	YES	100	130.20	$ 31.04	$ 606.31
47.88	06/27/2025	21	$ 34,466.25	487.500	$ 70.70	$ 23,339.06	$ 11,127.19		200.408	287.09	$ 6,552.87	304.000	87.01	YES	100	-	$ 22.83	$ -
47.88	06/27/2025	22	$ 26,568.41	531.900	$ 49.95	$ 25,464.71	$ 1,103.70		245.144	286.76	$ 595.02	304.000	87.01	YES	100	-	$ 2.08	$ -
47.81	06/28/2025	5	$ 1,082.87	20.080	$ 53.93	$ 960.09	$ 122.78		393.669	-	$ -	314.000	87.01	YES	100	-	$ 6.11	$ -
47.81	06/28/2025	10	$ 3,699.62	58.000	$ 63.79	$ 2,773.15	$ 926.47		377.058	-	$ -	314.000	87.01	YES	100	-	$ 15.97	$ -
47.81	06/28/2025	11	$ 3,268.03	56.300	$ 58.05	$ 2,691.87	$ 576.16		375.700	-	$ -	314.000	87.01	YES	100	-	$ 10.23	$ -
47.81	06/28/2025	13	$ 2,722.40	53.800	$ 50.60	$ 2,572.34	$ 150.06		376.117	-	$ -	314.000	87.01	YES	100	-	$ 2.79	$ -
47.81	06/28/2025	15	$ 25,229.88	526.500	$ 47.92	$ 25,173.54	$ 56.34	*Brown 3 was on Reserve Shutdown*	361.292	165.21	$ 17.68	314.000	87.01	YES	100	-	$ 0.11	$ -
47.81	06/28/2025	16	$ 16,009.95	313.000	$ 51.15	$ 14,965.47	$ 1,044.48	*Culley 3 was on outage all other units*	264.921	48.08	$ 160.44	314.000	87.01	YES	100	-	$ 3.34	$ -
47.81	06/28/2025	17	$ 19,379.63	363.800	$ 53.27	$ 17,394.37	$ 1,985.26	*online*	180.075	183.73	$ 1,002.59	314.000	87.01	YES	100	-	$ 5.46	$ -
47.81	06/28/2025	18	$ 17,681.90	283.500	$ 62.37	$ 13,554.99	$ 4,126.91		154.675	128.83	$ 1,875.31	314.000	87.01	YES	100	-	$ 14.56	$ -
47.81	06/28/2025	19	$ 30,370.84	446.200	$ 68.07	$ 21,334.16	$ 9,036.68		111.879	334.32	$ 6,770.85	314.000	87.01	YES	100	20.32	$ 20.25	$ 61.73
47.81	06/28/2025	20	$ 31,375.51	449.400	$ 69.82	$ 21,487.16	$ 9,888.35		100.678	348.72	$ 7,673.09	314.000	87.01	YES	100	34.72	$ 22.00	$ 114.60
47.81	06/28/2025	21	$ 24,899.15	427.600	$ 58.23	$ 20,444.84	$ 4,454.31		209.125	218.48	$ 2,275.86	314.000	87.01	YES	100	-	$ 10.42	$ -
47.81	06/29/2025	10	$ 3,818.11	68.500	$ 55.74	$ 3,275.19	$ 542.92		393.000	-	$ -	314.000	87.01	YES	100	-	$ 7.93	$ -
47.81	06/29/2025	13	$ 12,291.93	250.600	$ 49.05	$ 11,981.94	$ 309.99		179.741	70.86	$ 87.65	314.000	87.01	YES	100	-	$ 1.24	$ -
47.81	06/29/2025	14	$ 13,251.05	263.860	$ 50.22	$ 12,615.94	$ 635.11		157.200	106.66	$ 256.73	314.000	87.01	YES	100	-	$ 2.41	$ -
47.81	06/29/2025	15	$ 12,904.99	244.830	$ 52.71	$ 11,706.06	$ 1,198.93		140.000	104.83	$ 513.35	314.000	87.01	YES	100	-	$ 4.90	$ -
47.81	06/29/2025	16	$ 15,062.04	240.800	$ 62.55	$ 11,513.37	$ 3,548.67		120.479	120.32	$ 1,773.17	314.000	87.01	YES	100	-	$ 14.74	$ -
47.81	06/29/2025	17	$ 21,698.72	301.280	$ 72.02	$ 14,405.10	$ 7,293.62	*Culley 3 was on outage all other units*	48.096	253.18	$ 6,129.27	314.000	87.01	YES	100	-	$ 24.21	$ -
47.81	06/29/2025	18	$ 23,953.14	268.560	$ 89.19	$ 12,840.66	$ 11,112.48	*online*	25.224	243.34	$ 10,068.76	314.000	87.01	YES	100	-	$ 41.38	$ -
47.81	06/29/2025	19	$ 25,499.18	261.530	$ 97.50	$ 12,504.53	$ 12,994.65		13.000	248.53	$ 12,348.71	314.000	87.01	YES	100	-	$ 49.69	$ -
47.81	06/29/2025	20	$ 30,356.38	295.900	$ 102.59	$ 14,147.87	$ 16,208.51		26.000	269.90	$ 14,784.31	314.000	87.01	YES	100	-	$ 54.78	$ -
47.81	06/29/2025	21	$ 23,509.17	312.830	$ 75.15	$ 14,957.34	$ 8,551.83		43.492	269.34	$ 7,362.89	314.000	87.01	YES	100	-	$ 27.34	$ -
47.81	06/29/2025	22	$ 26,414.30	386.400	$ 68.36	$ 18,474.94	$ 7,939.36		143.178	243.22	$ 4,997.48	314.000	87.01	YES	100	-	$ 20.55	$ -
47.81	06/29/2025	23	$ 21,939.91	414.900	$ 52.88	$ 19,837.61	$ 2,102.30		249.192	165.71	$ 839.64	314.000	87.01	YES	100	-	$ 5.07	$ -
47.81	06/30/2025	9	$ 22,740.83	462.400	$ 49.18	$ 22,108.73	$ 632.10		381.650	80.75	$ 110.38	314.000	87.01	YES	100	-	$ 1.37	$ -
47.81	06/30/2025	10	$ 34,440.64	570.000	$ 60.42	$ 27,253.41	$ 7,187.23		352.000	218.00	$ 2,748.80	314.000	87.01	YES	100	-	$ 12.61	$ -
47.81	06/30/2025	11	$ 21,439.36	395.390	$ 54.22	$ 18,904.78	$ 2,534.58		187.742	207.65	$ 1,331.09	314.000	87.01	YES	100	-	$ 6.41	$ -
47.81	06/30/2025	12	$ 20,679.28	324.330	$ 63.76	$ 15,507.19	$ 5,172.09		153.696	170.63	$ 2,721.10	314.000	87.01	YES	100	-	$ 15.95	$ -
47.81	06/30/2025	13	$ 12,311.27	168.740	$ 72.96	$ 8,067.97	$ 4,243.30		83.592	85.15	$ 2,141.22	314.000	87.01	YES	100	-	$ 25.15	$ -
47.81	06/30/2025	14	$ 11,876.72	169.160	$ 70.21	$ 8,088.05	$ 3,788.67		75.000	94.16	$ 2,108.90	314.000	87.01	YES	100	-	$ 22.40	$ -
47.81	06/30/2025	15	$ 16,109.41	230.860	$ 69.78	$ 11,038.11	$ 5,071.30		78.000	152.86	$ 3,357.88	314.000	87.01	YES	100	-	$ 21.97	$ -
47.81	06/30/2025	16	$ 18,354.64	259.760	$ 70.66	$ 12,419.90	$ 5,934.74	*Culley 3 was on outage all other units*	75.000	184.76	$ 4,221.21	314.000	87.01	YES	100	-	$ 22.85	$ -
47.81	06/30/2025	17	$ 20,763.25	290.030	$ 71.59	$ 13,867.20	$ 6,896.05	*online*	47.000	243.03	$ 5,778.53	314.000	87.01	YES	100	-	$ 23.78	$ -
47.81	06/30/2025	18	$ 18,593.14	229.460	$ 81.03	$ 10,971.17	$ 7,621.97		12.250	217.21	$ 7,215.06	314.000	87.01	YES	100	-	$ 33.22	$ -
47.81	06/30/2025	19	$ 27,979.47	353.710	$ 79.10	$ 16,911.94	$ 11,067.53		43.396	310.31	$ 9,709.68	314.000	87.01	YES	100	-	$ 31.29	$ -
47.81	06/30/2025	20	$ 30,419.00	380.000	$ 80.05	$ 18,168.94	$ 12,250.06		112.283	267.72	$ 8,630.39	314.000	87.01	YES	100	-	$ 32.24	$ -
47.81	06/30/2025	21	$ 30,940.18	450.140	$ 68.73	$ 21,522.54	$ 9,417.64		67.942	382.20	$ 7,996.18	314.000	87.01	YES	100	68.20	$ 20.92	$ 214.02
47.81	06/30/2025	22	$ 30,199.20	520.050	$ 58.07	$ 24,865.15	$ 5,334.05		174.709	345.34	$ 3,542.09	314.000	87.01	YES	100	31.34	$ 10.26	$ 48.22
47.81	06/30/2025	23	$ 1,792.94	33.740	$ 53.14	$ 1,613.21	$ 179.73		330.858	-	$ -	314.000	87.01	YES	100	-	$ 5.33	$ -
47.81	06/30/2025	24	$ 2,884.22	53.650	$ 53.76	$ 2,565.17	$ 319.05		372.550	-	$ -	314.000	87.01	YES	100	-	$ 5.95	$ -
Total			**$ 5,659,219.15**	**65,237.190**		**$ 3,062,231.00**	**$ 2,596,988.28**		**40,547.153**	**37,530.399**	**$ 2,241,404.46**	**54,377.000**				**3,762.762**		**$ 54,409.75**

CenterPoint Energy Indiana South
Market Settlements Group
Purchased Power Over Benchmark Explanations Cause No. 38708 FAC 149

S55's through 07/31

Jul Benchmark Costs	Trade Date	HE	Cost of Purchased Power	Purchases Volume	Price	Purchases Volume @ Benchmark $	Amount Over Benchmark $	Reason for Purchasing Power	Available Capacity of Units Not Selected	MISO Economic Dispatch / Purchased MWs above Capacity	Purchase Power Costs at Risk	Test for Outages and Derates: MWs Out of Service	11% of Summer Rated Capacity 791	Are Unit MWs Out of Service > 11% Summer Capacity?	Recoverable @ 0%, 85%, or 100%	MWs Subject to 85% 15%	Over Benchmark Price	Total Unrecoverable Dollars
48.50	07/01/2025	1	$ 3,503.35	72.130	$ 48.57	$ 3,498.31	$ 5.05		384.058	-	$ -	312.000	87.01	YES	100	-	$ 0.07	$ -
48.50	07/01/2025	13	$ 16,008.16	325.700	$ 49.15	$ 15,796.45	$ 211.71		156.796	168.90	$ 109.79	291.000	87.01	YES	100	-	$ 0.65	$ -
48.50	07/01/2025	14	$ 16,758.25	328.400	$ 51.03	$ 15,927.40	$ 830.85		151.000	177.40	$ 448.82	291.000	87.01	YES	100	-	$ 2.53	$ -
48.50	07/01/2025	15	$ 17,304.31	334.060	$ 51.80	$ 16,201.91	$ 1,102.40		148.000	186.06	$ 614.00	291.000	87.01	YES	100	-	$ 3.30	$ -
48.50	07/01/2025	16	$ 13,319.54	229.410	$ 58.06	$ 11,126.39	$ 2,193.16		81.000	148.41	$ 1,418.80	291.000	87.01	YES	100	-	$ 9.56	$ -
48.50	07/01/2025	17	$ 19,638.19	265.740	$ 73.90	$ 12,888.39	$ 6,749.80	*Culley 3 was on outage all other units online*	53.000	212.74	$ 5,403.60	291.000	87.01	YES	100	-	$ 25.40	$ -
48.50	07/01/2025	18	$ 22,897.53	283.000	$ 80.91	$ 13,725.50	$ 9,172.03		59.000	224.00	$ 7,259.84	291.000	87.01	YES	100	-	$ 32.41	$ -
48.50	07/01/2025	19	$ 32,472.92	299.400	$ 108.46	$ 14,520.90	$ 17,952.02		52.992	246.41	$ 14,774.62	291.000	87.01	YES	100	-	$ 59.96	$ -
48.50	07/01/2025	20	$ 34,009.29	328.910	$ 103.40	$ 15,952.14	$ 18,057.16		25.000	303.91	$ 16,684.66	291.000	87.01	YES	100	12.91	$ 54.90	$ 106.31
48.50	07/01/2025	21	$ 29,865.21	381.380	$ 78.31	$ 18,496.93	$ 11,368.28		58.833	322.55	$ 9,614.57	312.000	87.01	YES	100	10.55	$ 29.81	$ 47.16
48.50	07/01/2025	22	$ 26,101.36	418.090	$ 62.43	$ 20,277.37	$ 5,824.00		135.837	282.25	$ 3,931.79	312.000	87.01	YES	100	-	$ 13.93	$ -
48.50	07/01/2025	23	$ 22,314.34	448.800	$ 49.72	$ 21,766.80	$ 547.54		205.855	242.95	$ 296.40	312.000	87.01	YES	100	-	$ 1.22	$ -
46.75	07/02/2025	12	$ 3,072.22	60.800	$ 50.53	$ 2,842.40	$ 229.82		366.896	-	$ -	42.000	87.01	NO	85	-	$ 3.78	$ -
46.75	07/02/2025	13	$ 2,485.10	45.200	$ 54.98	$ 2,113.10	$ 372.00		222.496	-	$ -	21.000	87.01	NO	85	-	$ 8.23	$ -
46.75	07/02/2025	14	$ 5,735.09	97.670	$ 58.72	$ 4,566.07	$ 1,169.02		216.583	-	$ -	21.000	87.01	NO	85	-	$ 11.97	$ -
46.75	07/02/2025	15	$ 5,175.31	90.430	$ 57.23	$ 4,227.60	$ 947.71		155.225	-	$ -	21.000	87.01	NO	85	-	$ 10.48	$ -
46.75	07/02/2025	16	$ 1.36	0.020	$ 68.00	$ 0.94	$ 0.43	*All units online load greater than generation*	106.271	-	$ -	21.000	87.01	NO	85	-	$ 21.25	$ -
46.75	07/02/2025	18	$ 3,014.88	35.900	$ 83.98	$ 1,678.33	$ 1,336.56		68.017	-	$ -	21.000	87.01	NO	85	-	$ 37.23	$ -
46.75	07/02/2025	19	$ 5,374.92	54.210	$ 99.15	$ 2,534.32	$ 2,840.60		59.000	-	$ -	21.000	87.01	NO	85	-	$ 52.40	$ -
46.75	07/02/2025	20	$ 13,875.47	141.370	$ 98.15	$ 6,609.05	$ 7,266.42		59.000	82.37	$ 4,233.82	21.000	87.01	NO	85	82.37	$ 51.40	$ 635.07
46.75	07/02/2025	21	$ 10,338.50	145.000	$ 71.30	$ 6,778.75	$ 3,559.75		127.558	17.44	$ 428.20	42.000	87.01	NO	85	17.44	$ 24.55	$ 64.23
46.75	07/02/2025	22	$ 10,909.00	207.830	$ 52.49	$ 9,716.05	$ 1,192.95		212.388	-	$ -	42.000	87.01	NO	85	-	$ 5.74	$ -
46.63	07/03/2025	12	$ 1,528.36	27.900	$ 54.78	$ 1,300.84	$ 227.52		214.862	-	$ -	44.000	87.01	NO	85	-	$ 8.15	$ -
46.63	07/03/2025	14	$ 4,298.98	73.600	$ 58.41	$ 3,431.60	$ 867.38		149.000	-	$ -	23.000	87.01	NO	85	-	$ 11.79	$ -
46.63	07/03/2025	19	$ 1,174.18	12.100	$ 97.04	$ 564.16	$ 610.02	*All units online load greater than generation*	45.533	-	$ -	23.000	87.01	NO	85	-	$ 50.41	$ -
46.63	07/03/2025	20	$ 12,382.56	140.090	$ 88.39	$ 6,531.70	$ 5,850.86		57.000	83.09	$ 3,470.26	23.000	87.01	NO	85	83.09	$ 41.77	$ 520.54
46.63	07/03/2025	21	$ 13,211.46	222.490	$ 59.38	$ 10,373.60	$ 2,837.86		169.412	53.08	$ 677.01	44.000	87.01	NO	85	53.08	$ 12.76	$ 101.55
46.63	07/03/2025	22	$ 14,103.61	288.890	$ 48.82	$ 13,469.50	$ 634.11		236.353	52.54	$ 115.32	44.000	87.01	NO	85	52.54	$ 2.20	$ 17.30
47.75	07/04/2025	15	$ 11,941.70	238.500	$ 50.07	$ 11,388.38	$ 553.33		364.730	-	$ -	44.000	87.01	NO	85	-	$ 2.32	$ -
47.75	07/04/2025	16	$ 7,221.44	127.700	$ 56.55	$ 6,097.68	$ 1,123.77		289.138	-	$ -	44.000	87.01	NO	85	-	$ 8.80	$ -
47.75	07/04/2025	17	$ 9,313.35	145.000	$ 64.23	$ 6,923.75	$ 2,389.60		243.706	-	$ -	44.000	87.01	NO	85	-	$ 16.48	$ -
47.75	07/04/2025	18	$ 6,409.09	89.600	$ 71.53	$ 4,278.40	$ 2,130.69	*Brown 3 was on Reserve Shutdown all other units online*	193.993	-	$ -	44.000	87.01	NO	85	-	$ 23.78	$ -
47.75	07/04/2025	19	$ 9,605.98	127.080	$ 75.59	$ 6,068.07	$ 3,537.91		162.558	-	$ -	44.000	87.01	NO	85	-	$ 27.84	$ -
47.75	07/04/2025	20	$ 10,279.58	141.670	$ 72.56	$ 6,764.74	$ 3,514.84		91.433	50.24	$ 1,246.38	44.000	87.01	NO	85	50.24	$ 24.81	$ 186.96
47.75	07/04/2025	21	$ 14,406.57	272.800	$ 52.81	$ 13,026.20	$ 1,380.37		242.408	30.39	$ 153.78	44.000	87.01	NO	85	30.39	$ 5.06	$ 23.07
47.75	07/05/2025	14	$ 14,206.09	277.710	$ 51.15	$ 13,260.65	$ 945.44		367.000	-	$ -	92.000	87.01	YES	100	-	$ 3.40	$ -
47.75	07/05/2025	15	$ 9,990.04	202.720	$ 49.28	$ 9,679.88	$ 310.16		280.000	-	$ -	68.000	87.01	NO	85	-	$ 1.53	$ -
47.75	07/05/2025	16	$ 6,670.77	114.500	$ 58.26	$ 5,467.38	$ 1,203.40		215.733	-	$ -	46.000	87.01	NO	85	-	$ 10.51	$ -
47.75	07/05/2025	17	$ 3,552.82	54.600	$ 65.07	$ 2,607.15	$ 945.67		166.416	-	$ -	46.000	87.01	NO	85	-	$ 17.32	$ -
47.75	07/05/2025	18	$ 4,852.56	61.100	$ 79.42	$ 2,917.53	$ 1,935.04	*All units online load greater than generation*	119.254	-	$ -	46.000	87.01	NO	85	-	$ 31.67	$ -
47.75	07/05/2025	19	$ 8,541.88	136.010	$ 62.80	$ 6,494.48	$ 2,047.40		84.000	52.01	$ 782.92	46.000	87.01	NO	85	52.01	$ 15.05	$ 117.44
47.75	07/05/2025	20	$ 12,704.83	144.900	$ 87.68	$ 6,918.98	$ 5,785.86		103.233	41.67	$ 1,663.76	46.000	87.01	NO	85	41.67	$ 39.93	$ 249.56
47.75	07/05/2025	21	$ 17,049.93	268.700	$ 63.45	$ 12,830.43	$ 4,219.51		142.863	125.84	$ 1,976.07	46.000	87.01	NO	85	125.84	$ 15.70	$ 296.41
47.75	07/05/2025	22	$ 12,774.68	239.900	$ 53.25	$ 11,455.23	$ 1,319.46		261.417	-	$ -	46.000	87.01	NO	85	-	$ 5.50	$ -
47.75	07/06/2025	12	$ 12,034.73	251.720	$ 47.81	$ 12,019.63	$ 15.10		432.725	-	$ -	46.000	87.01	NO	85	-	$ 0.06	$ -
47.75	07/06/2025	13	$ 4,121.21	77.700	$ 53.04	$ 3,710.18	$ 411.04		308.000	-	$ -	46.000	87.01	NO	85	-	$ 5.29	$ -
47.75	07/06/2025	14	$ 6,565.26	124.060	$ 52.92	$ 5,923.87	$ 641.40		263.862	-	$ -	46.000	87.01	NO	85	-	$ 5.17	$ -
47.75	07/06/2025	15	$ 6,224.27	113.810	$ 54.69	$ 5,434.43	$ 789.84		269.612	-	$ -	46.000	87.01	NO	85	-	$ 6.94	$ -
47.75	07/06/2025	16	$ 6,834.60	118.430	$ 57.71	$ 5,655.03	$ 1,179.57		258.008	-	$ -	46.000	87.01	NO	85	-	$ 9.96	$ -
47.75	07/06/2025	17	$ 10,316.42	149.600	$ 68.96	$ 7,143.40	$ 3,173.02	*Culley 2 was on Reserve Shutdown all other units on ine*	245.000	-	$ -	46.000	87.01	NO	85	-	$ 21.21	$ -
47.75	07/06/2025	18	$ 7,910.25	99.400	$ 79.58	$ 4,746.35	$ 3,163.90		186.446	-	$ -	46.000	87.01	NO	85	-	$ 31.83	$ -
47.75	07/06/2025	19	$ 17,350.75	218.540	$ 79.39	$ 10,435.29	$ 6,915.47		156.000	62.54	$ 1,979.01	46.000	87.01	NO	85	62.54	$ 31.64	$ 296.85
47.75	07/06/2025	20	$ 18,697.95	224.600	$ 83.25	$ 10,724.65	$ 7,973.30		180.242	44.36	$ 1,574.71	46.000	87.01	NO	85	44.36	$ 35.50	$ 236.21
47.75	07/06/2025	21	$ 16,183.98	258.200	$ 62.68	$ 12,329.05	$ 3,854.93		217.000	41.20	$ 615.12	46.000	87.01	NO	85	41.20	$ 14.93	$ 92.27
47.75	07/06/2025	22	$ 17,133.32	307.600	$ 55.70	$ 14,687.90	$ 2,445.42		323.575	-	$ -	46.000	87.01	NO	85	-	$ 7.95	$ -
47.75	07/07/2025	11	$ 5,757.35	113.200	$ 50.86	$ 5,405.30	$ 352.05		314.458	-	$ -	56.000	87.01	NO	85	-	$ 3.11	$ -
47.75	07/07/2025	12	$ 5,929.32	106.700	$ 55.57	$ 5,094.93	$ 834.40		196.000	-	$ -	56.000	87.01	NO	85	-	$ 7.82	$ -
47.75	07/07/2025	13	$ 5,464.18	91.100	$ 59.98	$ 4,350.03	$ 1,114.16		168.883	-	$ -	56.000	87.01	NO	85	-	$ 12.23	$ -
47.75	07/07/2025	14	$ 10,113.32	160.180	$ 63.14	$ 7,648.60	$ 2,464.73		172.275	-	$ -	56.000	87.01	NO	85	-	$ 15.39	$ -
47.75	07/07/2025	15	$ 4,475.16	72.180	$ 62.00	$ 3,446.60	$ 1,028.57		99.392	-	$ -	56.000	87.01	NO	85	-	$ 14.25	$ -
47.75	07/07/2025	16	$ 5,718.38	77.380	$ 73.90	$ 3,694.90	$ 2,023.49	*All units online load greater than generation*	151.725	-	$ -	56.000	87.01	NO	85	-	$ 26.15	$ -
47.75	07/07/2025	17	$ 1,168.87	15.390	$ 75.95	$ 734.87	$ 434.00		128.000	-	$ -	56.000	87.01	NO	85	-	$ 28.20	$ -
47.75	07/07/2025	18	$ 1,228.90	14.840	$ 82.81	$ 708.61	$ 520.29		68.117	-	$ -	56.000	87.01	NO	85	-	$ 35.06	$ -
47.75	07/07/2025	19	$ 4,727.78	46.870	$ 100.87	$ 2,238.04	$ 2,489.74		27.942	18.93	$ 1,005.46	56.000	87.01	NO	85	18.93	$ 53.12	$ 150.82
47.75	07/07/2025	20	$ 12,761.83	151.800	$ 84.07	$ 7,248.45	$ 5,513.38		58.096	93.70	$ 3,403.33	56.000	87.01	NO	85	93.70	$ 36.32	$ 510.50
47.75	07/07/2025	21	$ 10,672.10	140.700	$ 75.85	$ 6,718.43	$ 3,953.68		128.193	12.51	$ 351.45	56.000	87.01	NO	85	12.51	$ 28.10	$ 52.72
47.75	07/07/2025	22	$ 15,764.75	258.100	$ 61.08	$ 12,324.28	$ 3,440.48		218.295	39.81	$ 530.60	56.000	87.01	NO	85	39.81	$ 13.33	$ 79.59

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S55's through 07/31

Jul Benchmark Costs	Trade Date	HE	Cost of Purchased Power	Purchases Volume	Price	Purchases Volume @ Benchmark $	Amount Over Benchmark $	Reason for Purchasing Power	Available Capacity of Units Not Selected	MISO Economic Dispatch / Purchased MWs above Capacity	Purchase Power Costs at Risk	Test for Outages and Derates: MWs Out of Service	11% of Summer Rated Capacity	Are Unit MWs Out of Service > 11% Summer Capacity?	Recoverable @ 0%, 85%, or 100%	MWs Subject to 85% 15%	Over Benchmark Price	Total Unrecoverable Dollars
48.00	07/08/2025	11	$ 3,319.64	66.300	$ 50.07	$ 3,182.40	$ 137.24		237.950	-	$ -	54.000	87.01	NO	85	-	$ 2.07	$ -
48.00	07/08/2025	12	$ 2,258.27	38.570	$ 58.55	$ 1,851.36	$ 406.91		162.000	-	$ -	54.000	87.01	NO	85	-	$ 10.55	$ -
48.00	07/08/2025	13	$ 2,566.61	49.150	$ 52.22	$ 2,359.20	$ 207.41		101.874	-	$ -	54.000	87.01	NO	85	-	$ 4.22	$ -
48.00	07/08/2025	14	$ 11,479.26	72.300	$ 158.77	$ 3,470.40	$ 8,008.86		75.000	-	$ -	54.000	87.01	NO	85	-	$ 110.77	$ -
48.00	07/08/2025	15	$ 2,257.17	33.140	$ 68.11	$ 1,590.72	$ 666.45	*All units online load greater than generation*	35.000	-	$ -	51.000	87.01	NO	85	-	$ 20.11	$ -
48.00	07/08/2025	19	$ 5,962.98	56.650	$ 105.26	$ 2,719.20	$ 3,243.78		60.767	-	$ -	54.000	87.01	NO	85	-	$ 57.26	$ -
48.00	07/08/2025	20	$ 12,475.81	137.900	$ 90.47	$ 6,619.20	$ 5,856.61		91.075	46.83	$ 1,988.66	54.000	87.01	NO	85	46.83	$ 42.47	$ 298.30
48.00	07/08/2025	21	$ 10,243.38	133.100	$ 76.96	$ 6,388.80	$ 3,854.58		97.875	35.23	$ 1,020.12	54.000	87.01	NO	85	35.23	$ 28.96	$ 153.02
48.00	07/08/2025	22	$ 14,779.82	234.340	$ 63.07	$ 11,248.32	$ 3,531.50		185.941	48.40	$ 729.37	54.000	87.01	NO	85	48.40	$ 15.07	$ 109.41
48.00	07/08/2025	23	$ 10,922.18	202.300	$ 53.99	$ 9,710.40	$ 1,211.78		227.179	-	$ -	54.000	87.01	NO	85	-	$ 5.99	$ -
47.50	07/09/2025	6	$ 1,863.12	36.500	$ 51.04	$ 1,733.75	$ 129.37		372.250	-	$ -	187.000	87.01	YES	100	-	$ 3.54	$ -
47.50	07/09/2025	9	$ 9,740.10	203.300	$ 47.91	$ 9,656.75	$ 83.35		388.633	-	$ -	52.000	87.01	NO	85	-	$ 0.41	$ -
47.50	07/09/2025	10	$ 11,601.52	239.800	$ 48.38	$ 11,390.50	$ 211.02		372.442	-	$ -	52.000	87.01	NO	85	-	$ 0.88	$ -
47.50	07/09/2025	11	$ 3,469.58	65.600	$ 52.89	$ 3,116.00	$ 353.58		234.862	-	$ -	52.000	87.01	NO	85	-	$ 5.39	$ -
47.50	07/09/2025	12	$ 4,321.11	77.900	$ 55.47	$ 3,700.25	$ 620.86		207.316	-	$ -	52.000	87.01	NO	85	-	$ 7.97	$ -
47.50	07/09/2025	13	$ 3,238.83	54.390	$ 59.55	$ 2,583.53	$ 655.31		189.009	-	$ -	52.000	87.01	NO	85	-	$ 12.05	$ -
47.50	07/09/2025	14	$ 2,665.85	42.060	$ 63.38	$ 1,997.85	$ 668.00		102.625	-	$ -	42.000	87.01	NO	85	-	$ 15.88	$ -
47.50	07/09/2025	15	$ 2,189.38	38.940	$ 56.22	$ 1,849.65	$ 339.73	*Brown 3 short run time all other units online.*	112.570	-	$ -	42.000	87.01	NO	85	-	$ 8.72	$ -
47.50	07/09/2025	16	$ 1,119.89	21.720	$ 51.56	$ 1,031.70	$ 88.19		93.783	-	$ -	42.000	87.01	NO	85	-	$ 4.06	$ -
47.50	07/09/2025	17	$ 1,457.56	18.800	$ 77.53	$ 893.00	$ 564.56		118.350	-	$ -	42.000	87.01	NO	85	-	$ 30.03	$ -
47.50	07/09/2025	18	$ 1,986.35	23.800	$ 83.46	$ 1,130.50	$ 855.85		135.287	-	$ -	42.000	87.01	NO	85	-	$ 35.96	$ -
47.50	07/09/2025	19	$ 4,807.69	49.800	$ 96.54	$ 2,365.50	$ 2,442.19		157.642	-	$ -	42.000	87.01	NO	85	-	$ 49.04	$ -
47.50	07/09/2025	20	$ 9,608.60	109.800	$ 87.51	$ 5,215.50	$ 4,393.10		112.737	-	$ -	42.000	87.01	NO	85	-	$ 40.01	$ -
47.50	07/09/2025	21	$ 9,247.06	142.900	$ 64.71	$ 6,787.75	$ 2,459.31		134.247	8.65	$ 148.92	42.000	87.01	NO	85	8.65	$ 17.21	$ 22.34
47.50	07/09/2025	22	$ 11,613.89	206.800	$ 56.16	$ 9,823.00	$ 1,790.89		235.254	-	$ -	42.000	87.01	NO	85	-	$ 8.66	$ -
46.00	07/10/2025	7	$ 3,534.53	73.400	$ 48.15	$ 3,376.40	$ 158.13		402.511	-	$ -	84.000	87.01	NO	85	-	$ 2.15	$ -
46.00	07/10/2025	8	$ 13,096.40	186.900	$ 70.07	$ 8,597.40	$ 4,499.00		376.196	-	$ -	110.000	87.01	YES	100	-	$ 24.07	$ -
46.00	07/10/2025	9	$ 9,720.30	182.100	$ 53.38	$ 8,376.60	$ 1,343.70		422.596	-	$ -	44.000	87.01	NO	85	-	$ 7.38	$ -
46.00	07/10/2025	10	$ 1,961.02	41.600	$ 47.14	$ 1,913.60	$ 47.42		424.542	-	$ -	44.000	87.01	NO	85	-	$ 1.14	$ -
46.00	07/10/2025	11	$ 8,695.33	95.100	$ 91.43	$ 4,374.60	$ 4,320.73		404.568	-	$ -	44.000	87.01	NO	85	-	$ 45.43	$ -
46.00	07/10/2025	12	$ 2,542.32	49.500	$ 51.36	$ 2,277.00	$ 265.32		148.812	-	$ -	119.000	87.01	YES	100	-	$ 5.36	$ -
46.00	07/10/2025	13	$ 1,415.69	25.900	$ 54.66	$ 1,191.40	$ 224.29		138.824	-	$ -	119.000	87.01	YES	100	-	$ 8.66	$ -
46.00	07/10/2025	14	$ 4,898.84	73.800	$ 66.38	$ 3,394.80	$ 1,504.04		135.125	-	$ -	127.000	87.01	YES	100	-	$ 20.38	$ -
46.00	07/10/2025	15	$ 5,817.59	96.700	$ 60.16	$ 4,448.20	$ 1,369.39	*Brown 3 was returning from outage all other units online.*	76.538	20.16	$ 285.52	127.000	87.01	YES	100	-	$ 14.16	$ -
46.00	07/10/2025	16	$ 4,832.23	77.100	$ 62.67	$ 3,546.60	$ 1,285.63		66.760	10.34	$ 172.42	127.000	87.01	YES	100	-	$ 16.67	$ -
46.00	07/10/2025	17	$ 2,772.61	25.100	$ 110.46	$ 1,154.60	$ 1,618.01		79.855	-	$ -	52.000	87.01	NO	85	-	$ 64.46	$ -
46.00	07/10/2025	18	$ 1,765.66	27.730	$ 63.67	$ 1,275.58	$ 490.08		69.225	-	$ -	52.000	87.01	NO	85	-	$ 17.67	$ -
46.00	07/10/2025	19	$ 6,634.01	77.800	$ 85.27	$ 3,578.80	$ 3,055.21		42.570	35.23	$ 1,383.48	52.000	87.01	NO	85	35.23	$ 39.27	$ 207.52
46.00	07/10/2025	20	$ 10,587.14	131.550	$ 80.48	$ 6,051.30	$ 4,535.84		33.937	97.61	$ 3,365.69	52.000	87.01	NO	85	97.61	$ 34.48	$ 504.85
46.00	07/10/2025	21	$ 12,741.76	201.190	$ 63.33	$ 9,254.74	$ 3,487.02		99.017	102.17	$ 1,770.86	52.000	87.01	NO	85	102.17	$ 17.33	$ 265.63
46.00	07/10/2025	22	$ 9,087.30	179.520	$ 50.62	$ 8,257.92	$ 829.38		114.112	65.41	$ 302.18	52.000	87.01	NO	85	65.41	$ 4.62	$ 45.33
46.00	07/10/2025	23	$ 1,203.25	6.600	$ 182.31	$ 303.60	$ 899.65		366.166	-	$ -	52.000	87.01	NO	85	-	$ 136.31	$ -
46.00	07/10/2025	24	$ 1,265.15	12.400	$ 102.03	$ 570.40	$ 694.75		376.145	-	$ -	52.000	87.01	NO	85	-	$ 56.03	$ -
46.38	07/11/2025	10	$ 5,802.41	99.290	$ 58.44	$ 4,604.57	$ 1,197.84		229.783	-	$ -	54.000	87.01	NO	85	-	$ 12.06	$ -
46.38	07/11/2025	11	$ 2,063.15	33.080	$ 62.37	$ 1,534.09	$ 529.07		178.460	-	$ -	54.000	87.01	NO	85	-	$ 15.99	$ -
46.38	07/11/2025	13	$ 3,888.90	82.280	$ 47.26	$ 3,815.74	$ 73.16		130.952	-	$ -	54.000	87.01	NO	85	-	$ 0.89	$ -
46.38	07/11/2025	14	$ 4,663.09	85.380	$ 54.62	$ 3,959.50	$ 703.59		120.971	-	$ -	54.000	87.01	NO	85	-	$ 8.24	$ -
46.38	07/11/2025	15	$ 4,573.11	82.740	$ 55.27	$ 3,837.07	$ 736.04		120.796	-	$ -	54.000	87.01	NO	85	-	$ 8.90	$ -
46.38	07/11/2025	16	$ 2,049.61	41.620	$ 49.25	$ 1,930.13	$ 119.48	*Brown 3 short run time all other units online.*	113.221	-	$ -	54.000	87.01	NO	85	-	$ 2.87	$ -
46.38	07/11/2025	18	$ 5,545.41	115.020	$ 48.21	$ 5,334.05	$ 211.36		72.531	42.49	$ 78.08	54.000	87.01	NO	85	42.49	$ 1.84	$ 11.71
46.38	07/11/2025	19	$ 5,106.88	57.400	$ 88.97	$ 2,661.93	$ 2,444.96		101.629	-	$ -	54.000	87.01	NO	85	-	$ 42.60	$ -
46.38	07/11/2025	20	$ 17,306.97	253.640	$ 68.23	$ 11,762.56	$ 5,544.42		70.979	182.66	$ 3,992.86	54.000	87.01	NO	85	182.66	$ 21.86	$ 598.93
46.38	07/11/2025	21	$ 18,752.18	287.260	$ 65.28	$ 13,321.68	$ 5,430.50		118.259	169.00	$ 3,194.87	54.000	87.01	NO	85	169.00	$ 18.90	$ 479.23
46.38	07/11/2025	22	$ 19,694.46	298.550	$ 65.97	$ 13,845.26	$ 5,849.20		180.129	118.42	$ 2,320.11	54.000	87.01	NO	85	118.42	$ 19.59	$ 348.02
46.38	07/11/2025	23	$ 10,472.27	217.900	$ 48.06	$ 10,105.11	$ 367.16		292.250	-	$ -	54.000	87.01	NO	85	-	$ 1.68	$ -
47.63	07/12/2025	1	$ 4,234.55	67.100	$ 63.11	$ 3,195.64	$ 1,038.91		388.250	-	$ -	52.000	87.01	NO	85	-	$ 15.48	$ -
47.63	07/12/2025	11	$ 20,894.96	352.180	$ 59.33	$ 16,772.57	$ 4,122.39		371.417	-	$ -	312.000	87.01	YES	100	-	$ 11.71	$ -
47.63	07/12/2025	14	$ 12,209.23	250.600	$ 48.72	$ 11,934.83	$ 274.40		372.121	-	$ -	194.000	87.01	YES	100	-	$ 1.09	$ -
47.63	07/12/2025	15	$ 25,092.06	513.410	$ 48.87	$ 24,451.15	$ 640.91		357.000	156.41	$ 195.25	190.000	87.01	YES	100	-	$ 1.25	$ -
47.63	07/12/2025	16	$ 1,241.63	24.100	$ 51.52	$ 1,147.76	$ 93.87		202.000	-	$ -	188.000	87.01	YES	100	-	$ 3.89	$ -
47.63	07/12/2025	17	$ 1,014.47	17.300	$ 58.64	$ 823.91	$ 190.56	*Brown 3 was on Reserve Shutdown all other units online.*	203.315	-	$ -	150.000	87.01	YES	100	-	$ 11.01	$ -
47.63	07/12/2025	18	$ 287.51	4.500	$ 63.89	$ 214.31	$ 73.20		193.333	-	$ -	84.000	87.01	NO	85	-	$ 16.27	$ -
47.63	07/12/2025	19	$ 5,130.95	61.500	$ 83.43	$ 2,928.94	$ 2,202.01		156.150	-	$ -	58.000	87.01	NO	85	-	$ 35.81	$ -
47.63	07/12/2025	20	$ 8,692.23	112.100	$ 77.54	$ 5,338.76	$ 3,353.47		161.871	-	$ -	52.000	87.01	NO	85	-	$ 29.91	$ -
47.63	07/12/2025	21	$ 5,464.05	90.300	$ 60.51	$ 4,300.54	$ 1,163.51		192.546	-	$ -	52.000	87.01	NO	85	-	$ 12.88	$ -
47.63	07/12/2025	22	$ 9,716.76	184.000	$ 52.81	$ 8,763.00	$ 953.76		238.613	-	$ -	52.000	87.01	NO	85	-	$ 5.18	$ -
47.63	07/13/2025	10	$ 2,412.43	39.400	$ 61.23	$ 1,876.43	$ 536.01		383.487	-	$ -	54.000	87.01	NO	85	-	$ 13.60	$ -
47.63	07/13/2025	11	$ 4,073.76	55.200	$ 73.80	$ 2,628.90	$ 1,444.86		375.704	-	$ -	54.000	87.01	NO	85	-	$ 26.18	$ -

CenterPoint Energy Indiana South
Market Settlements Group
Purchased Power Over Benchmark Explanations Cause No. 38708 FAC 149

S55's through 07/31

Jul Benchmark Costs	Trade Date	HE	Cost of Purchased Power	Purchases Volume	Price	Purchases Volume @ Benchmark $	Amount Over Benchmark $	Reason for Purchasing Power	Available Capacity of Units Not Selected	MISO Economic Dispatch / Purchased MWs above Capacity	Purchase Power Costs at Risk	Test for Outages and Derates: MWs Out of Service	11% of Summer Rated Capacity	Are Unit MWs Out of Service > 11% Summer Capacity?	Recoverable @ 0%, 85%, or 100%	MWs Subject to 85% 15%	Over Benchmark Price	Total Unrecoverable Dollars
47.63	07/13/2025	12	$ 3,362.69	38.400	$ 87.57	$ 1,828.80	$ 1,533.89		374.388	-	$ -	54.000	87.01	NO	85	-	$ 39.95	$ -
47.63	07/13/2025	13	$ 6,888.51	82.300	$ 83.70	$ 3,919.54	$ 2,968.97		370.458	-	$ -	54.000	87.01	NO	85	-	$ 36.08	$ -
47.63	07/13/2025	15	$ 19,474.82	183.460	$ 106.15	$ 8,737.28	$ 10,737.54	*Culley 2 tripped offline all other units*	439.000	-	$ -	54.000	87.01	NO	85	-	$ 58.53	$ -
47.63	07/13/2025	16	$ 469.68	9.500	$ 49.44	$ 452.44	$ 17.24	*online*	191.000	-	$ -	132.000	87.01	YES	100	-	$ 1.82	$ -
47.63	07/13/2025	19	$ 7,587.66	149.900	$ 50.62	$ 7,138.99	$ 448.67		73.000	76.90	$ 230.17	132.000	87.01	YES	100	-	$ 2.99	$ -
47.63	07/13/2025	20	$ 8,829.62	95.800	$ 92.17	$ 4,562.48	$ 4,267.15		40.000	55.80	$ 2,485.46	132.000	87.01	YES	100	-	$ 44.54	$ -
47.63	07/13/2025	21	$ 10,500.35	180.100	$ 58.30	$ 8,577.26	$ 1,923.09		97.200	82.90	$ 885.20	132.000	87.01	YES	100	-	$ 10.68	$ -
47.63	07/13/2025	22	$ 9,377.47	165.300	$ 56.73	$ 7,872.41	$ 1,505.06		202.967	-	$ -	132.000	87.01	YES	100	-	$ 9.11	$ -
47.63	07/14/2025	8	$ 1,361.23	27.600	$ 49.32	$ 1,314.45	$ 46.78		208.000	-	$ -	122.000	87.01	YES	100	-	$ 1.69	$ -
47.63	07/14/2025	12	$ 2,407.52	40.300	$ 59.74	$ 1,919.29	$ 488.23		114.000	-	$ -	122.000	87.01	YES	100	-	$ 12.11	$ -
47.63	07/14/2025	15	$ 2,878.42	46.000	$ 62.57	$ 2,190.75	$ 687.67		40.000	6.00	$ 89.70	122.000	87.01	YES	100	-	$ 14.95	$ -
47.63	07/14/2025	16	$ 6,246.30	55.800	$ 111.94	$ 2,657.48	$ 3,588.83		14.884	40.92	$ 2,631.55	122.000	87.01	YES	100	-	$ 64.32	$ -
47.63	07/14/2025	17	$ 3,215.36	63.300	$ 50.80	$ 3,014.66	$ 200.70		31.796	31.50	$ 99.89	122.000	87.01	YES	100	-	$ 3.17	$ -
47.63	07/14/2025	18	$ 10,119.20	176.800	$ 57.24	$ 8,420.10	$ 1,699.10	*Culley 2 was on outage all other units*	53.767	123.03	$ 1,182.38	122.000	87.01	YES	100	1.03	$ 9.61	$ 1.49
47.63	07/14/2025	19	$ 13,548.39	171.400	$ 79.05	$ 8,162.93	$ 5,385.47	*online*	44.113	127.29	$ 3,999.41	122.000	87.01	YES	100	5.29	$ 31.42	$ 24.92
47.63	07/14/2025	20	$ 19,823.82	188.500	$ 105.17	$ 8,977.31	$ 10,846.51		36.000	152.50	$ 8,775.03	122.000	87.01	YES	100	30.50	$ 57.54	$ 263.25
47.63	07/14/2025	21	$ 13,825.21	206.000	$ 67.11	$ 9,810.75	$ 4,014.46		65.475	140.53	$ 2,738.50	122.000	87.01	YES	100	18.53	$ 19.49	$ 54.15
47.63	07/14/2025	22	$ 8,421.24	120.700	$ 69.77	$ 5,748.34	$ 2,672.90		178.304	-	$ -	122.000	87.01	YES	100	-	$ 22.15	$ -
47.63	07/14/2025	23	$ 8,240.04	141.000	$ 58.44	$ 6,715.13	$ 1,524.92		258.229	-	$ -	122.000	87.01	YES	100	-	$ 10.82	$ -
47.63	07/14/2025	24	$ 15,602.53	322.900	$ 48.32	$ 15,378.11	$ 224.42		363.558	-	$ -	122.000	87.01	YES	100	-	$ 0.70	$ -
47.81	07/15/2025	9	$ 12,910.78	239.000	$ 54.02	$ 11,427.31	$ 1,483.47		140.000	99.00	$ 614.49	101.000	87.01	YES	100	-	$ 6.21	$ -
47.81	07/15/2025	10	$ 11,873.36	193.000	$ 61.52	$ 9,227.91	$ 2,645.45		97.000	96.00	$ 1,315.87	101.000	87.01	YES	100	-	$ 13.71	$ -
47.81	07/15/2025	11	$ 14,521.47	212.800	$ 68.24	$ 10,174.61	$ 4,346.86		99.000	113.80	$ 2,324.59	101.000	87.01	YES	100	12.80	$ 20.43	$ 39.22
47.81	07/15/2025	12	$ 14,152.80	207.580	$ 68.18	$ 9,925.02	$ 4,227.78		96.000	111.58	$ 2,272.55	342.000	87.01	YES	100	-	$ 20.37	$ -
47.81	07/15/2025	13	$ 16,252.07	196.210	$ 82.83	$ 9,381.39	$ 6,870.68		82.000	114.21	$ 3,999.29	342.000	87.01	YES	100	-	$ 35.02	$ -
47.81	07/15/2025	14	$ 20,901.25	247.070	$ 84.60	$ 11,813.16	$ 9,088.09		41.000	206.07	$ 7,579.97	342.000	87.01	YES	100	-	$ 36.78	$ -
47.81	07/15/2025	15	$ 21,791.94	224.620	$ 97.02	$ 10,739.76	$ 11,052.18		26.879	197.74	$ 9,729.63	342.000	87.01	YES	100	-	$ 49.20	$ -
47.81	07/15/2025	16	$ 30,139.59	224.470	$ 134.27	$ 10,732.58	$ 19,407.01	*Brown 6 and Culley 2 were on outage*	16.696	207.77	$ 17,963.52	342.000	87.01	YES	100	-	$ 86.46	$ -
47.81	07/15/2025	17	$ 125,519.64	261.680	$ 479.67	$ 12,511.71	$ 113,007.93		0.125	261.56	$ 112,953.95	342.000	87.01	YES	100	-	$ 431.86	$ -
47.81	07/15/2025	18	$ 55,675.28	349.910	$ 159.11	$ 16,730.25	$ 38,945.03		4.000	345.91	$ 38,499.83	342.000	87.01	YES	100	3.91	$ 111.30	$ 65.28
47.81	07/15/2025	19	$ 53,286.29	351.620	$ 151.55	$ 16,812.01	$ 36,474.28		11.000	340.62	$ 35,333.23	341.000	87.01	YES	100	-	$ 103.73	$ -
47.81	07/15/2025	20	$ 37,752.54	399.690	$ 94.45	$ 19,110.38	$ 18,642.16		49.000	350.69	$ 16,356.73	342.000	87.01	YES	100	8.69	$ 46.64	$ 60.80
47.81	07/15/2025	21	$ 16,113.87	166.500	$ 96.78	$ 7,960.86	$ 8,153.01		58.000	108.50	$ 5,312.92	342.000	87.01	YES	100	-	$ 48.97	$ -
47.81	07/15/2025	22	$ 17,616.04	235.100	$ 74.93	$ 11,240.84	$ 6,375.20		97.000	138.10	$ 3,744.86	342.000	87.01	YES	100	-	$ 27.12	$ -
47.81	07/15/2025	23	$ 14,515.42	259.900	$ 55.85	$ 12,426.60	$ 2,088.82		133.850	126.05	$ 1,013.07	342.000	87.01	YES	100	-	$ 8.04	$ -
48.69	07/16/2025	9	$ 6,292.33	126.200	$ 49.86	$ 6,144.43	$ 147.90		151.000	-	$ -	340.000	87.01	YES	100	-	$ 1.17	$ -
48.69	07/16/2025	10	$ 7,523.82	139.900	$ 53.78	$ 6,811.45	$ 712.37		142.000	-	$ -	340.000	87.01	YES	100	-	$ 5.09	$ -
48.69	07/16/2025	11	$ 12,521.60	196.000	$ 63.89	$ 9,542.85	$ 2,978.75		94.000	102.00	$ 1,550.17	340.000	87.01	YES	100	-	$ 15.20	$ -
48.69	07/16/2025	12	$ 13,590.50	192.000	$ 70.78	$ 9,348.10	$ 4,242.40		86.000	106.00	$ 2,342.16	340.000	87.01	YES	100	-	$ 22.10	$ -
48.69	07/16/2025	13	$ 12,412.11	172.080	$ 72.13	$ 8,378.23	$ 4,033.88		37.375	134.71	$ 3,157.74	340.000	87.01	YES	100	-	$ 23.44	$ -
48.69	07/16/2025	14	$ 17,833.62	145.340	$ 122.70	$ 7,076.31	$ 10,757.31		8.650	136.69	$ 10,117.08	318.000	87.01	YES	100	-	$ 74.01	$ -
48.69	07/16/2025	15	$ 11,408.73	139.410	$ 81.84	$ 6,787.59	$ 4,621.14	*Brown 6 was on outage*	40.000	99.41	$ 3,295.22	99.000	87.01	YES	100	0.41	$ 33.15	$ 2.04
48.69	07/16/2025	16	$ 6,170.79	66.450	$ 92.86	$ 3,235.32	$ 2,935.47		47.696	18.75	$ 828.47	99.000	87.01	YES	100	-	$ 44.18	$ -
48.69	07/16/2025	17	$ 9,345.46	93.370	$ 100.09	$ 4,546.00	$ 4,799.46		48.313	45.06	$ 2,316.05	99.000	87.01	YES	100	-	$ 51.40	$ -
48.69	07/16/2025	18	$ 186.57	3.820	$ 48.84	$ 185.99	$ 0.58		94.259	-	$ -	114.000	87.01	YES	100	-	$ 0.15	$ -
48.69	07/16/2025	19	$ 3,658.22	34.900	$ 104.82	$ 1,699.21	$ 1,959.01		107.912	-	$ -	102.000	87.01	YES	100	-	$ 56.13	$ -
48.69	07/16/2025	20	$ 12,348.38	127.500	$ 96.85	$ 6,207.72	$ 6,140.66		127.200	0.30	$ 14.45	90.000	87.01	YES	100	-	$ 48.16	$ -
48.69	07/16/2025	21	$ 9,767.39	115.700	$ 84.42	$ 5,633.20	$ 4,134.19		152.075	-	$ -	72.000	87.01	NO	85	-	$ 35.73	$ -
48.69	07/16/2025	22	$ 13,917.69	239.300	$ 58.16	$ 11,651.04	$ 2,266.65		272.028	-	$ -	42.000	87.01	NO	85	-	$ 9.47	$ -
50.31	07/17/2025	1	$ 15,842.01	292.720	$ 54.12	$ 14,727.62	$ 1,114.39		369.000	-	$ -	32.000	87.01	NO	85	-	$ 3.81	$ -
50.31	07/17/2025	6	$ 15,264.48	294.000	$ 51.92	$ 14,792.02	$ 472.46		0.000	294.00	$ 472.46	401.000	87.01	YES	100	-	$ 1.61	$ -
50.31	07/17/2025	9	$ 12,363.32	204.150	$ 60.56	$ 10,271.40	$ 2,091.92		149.000	55.15	$ 565.12	11.000	87.01	NO	85	55.15	$ 10.25	$ 84.77
50.31	07/17/2025	10	$ 6,393.53	96.100	$ 66.53	$ 4,835.08	$ 1,558.45		137.000	-	$ -	11.000	87.01	NO	85	-	$ 16.22	$ -
50.31	07/17/2025	13	$ 3,855.08	36.600	$ 105.33	$ 1,841.46	$ 2,013.62		58.000	-	$ -	11.000	87.01	NO	85	-	$ 55.02	$ -
50.31	07/17/2025	14	$ 12,515.42	102.100	$ 122.58	$ 5,136.96	$ 7,378.46		55.000	47.10	$ 3,403.78	11.000	87.01	NO	85	47.10	$ 72.27	$ 510.57
50.31	07/17/2025	15	$ 21,190.28	158.290	$ 133.87	$ 7,964.04	$ 13,226.24		56.000	102.29	$ 8,547.04	11.000	87.01	NO	85	102.29	$ 83.56	$ 1,282.06
50.31	07/17/2025	16	$ 25,070.74	261.050	$ 96.04	$ 13,134.21	$ 11,936.53	*Brown 6 was on Reserve Shutdown*	49.000	212.05	$ 9,696.00	11.000	87.01	NO	85	212.05	$ 45.73	$ 1,454.40
50.31	07/17/2025	17	$ 31,281.16	273.520	$ 114.37	$ 13,761.61	$ 17,519.55		271.000	2.52	$ 161.41	32.000	87.01	NO	85	2.52	$ 64.05	$ 24.21
50.31	07/17/2025	18	$ 27,904.86	218.340	$ 127.80	$ 10,985.34	$ 16,919.52		260.000	-	$ -	32.000	87.01	NO	85	-	$ 77.49	$ -
50.31	07/17/2025	19	$ 32,440.91	253.740	$ 127.85	$ 12,766.42	$ 19,674.49		274.000	-	$ -	32.000	87.01	NO	85	-	$ 77.54	$ -
50.31	07/17/2025	20	$ 27,865.93	232.100	$ 120.06	$ 11,677.65	$ 16,188.28		278.000	-	$ -	32.000	87.01	NO	85	-	$ 69.75	$ -
50.31	07/17/2025	21	$ 21,078.10	205.000	$ 102.82	$ 10,314.17	$ 10,763.94		268.000	-	$ -	32.000	87.01	NO	85	-	$ 52.51	$ -
50.31	07/17/2025	22	$ 18,112.74	285.240	$ 63.50	$ 14,351.28	$ 3,761.46		361.775	-	$ -	32.000	87.01	NO	85	-	$ 13.19	$ -
50.31	07/17/2025	23	$ 16,496.66	275.910	$ 59.79	$ 13,881.86	$ 2,614.80		369.000	-	$ -	32.000	87.01	NO	85	-	$ 9.48	$ -
51.25	07/18/2025	13	$ 16,698.13	311.300	$ 53.64	$ 15,954.13	$ 744.01		151.625	159.68	$ 381.62	272.000	87.01	YES	100	-	$ 2.39	$ -
51.25	07/18/2025	14	$ 19,076.01	326.700	$ 58.39	$ 16,743.38	$ 2,332.64		151.283	175.42	$ 1,252.48	272.000	87.01	YES	100	-	$ 7.14	$ -
51.25	07/18/2025	15	$ 20,266.92	343.100	$ 59.07	$ 17,583.88	$ 2,683.05		151.837	191.26	$ 1,495.68	272.000	87.01	YES	100	-	$ 7.82	$ -
51.25	07/18/2025	16	$ 20,806.37	343.000	$ 60.66	$ 17,578.75	$ 3,227.62	*Brown 3 and Brown 4 were on*	151.000	192.00	$ 1,806.71	272.000	87.01	YES	100	-	$ 9.41	$ -
51.25	07/18/2025	17	$ 24,097.48	372.300	$ 64.73	$ 19,080.38	$ 5,017.11	*Reserve Shutdown Brown 6 was on*	151.000	221.30	$ 2,982.23	272.000	87.01	YES	100	-	$ 13.48	$ -

CenterPoint Energy Indiana South
Market Settlements Group
Purchased Power Over Benchmark Explanations Cause No. 38708 FAC 149

S55's through 07/31

Jul Benchmark Costs	Trade Date	HE	Cost of Purchased Power	Purchases Volume	Price	Purchases Volume @ Benchmark $	Amount Over Benchmark $	Reason for Purchasing Power	Available Capacity of Units Not Selected	MISO Economic Dispatch / Purchased MWs above Capacity	Purchase Power Costs at Risk	Test for Outages and Derates: MWs Out of Service	11% of Summer Rated Capacity	Are Unit MWs Out of Service > 11% Summer Capacity?	Recoverable @ 0%, 85%, or 100%	MWs Subject to 85% 15%	Over Benchmark Price	Total Unrecoverable Dollars
51.25	07/18/2025	18	$ 27,034.46	410.600	$ 65.84	$ 21,043.25	$ 5,991.21	outage	151.000	259.60	$ 3,787.92	272.000	87.01	YES	100	-	$ 14.59	$ -
51.25	07/18/2025	19	$ 36,727.43	477.800	$ 76.87	$ 24,487.25	$ 12,240.18		151.000	326.80	$ 8,371.89	272.000	87.01	YES	100	54.80	$ 25.62	$ 210.58
51.25	07/18/2025	20	$ 30,263.88	471.400	$ 64.20	$ 24,159.25	$ 6,104.63		151.000	320.40	$ 4,149.18	272.000	87.01	YES	100	48.40	$ 12.95	$ 94.02
51.25	07/18/2025	21	$ 25,910.65	435.400	$ 59.51	$ 22,314.25	$ 3,596.40		151.208	284.19	$ 2,347.42	272.000	87.01	YES	100	12.19	$ 8.26	$ 15.11
51.31	07/19/2025	13	$ 8,789.36	151.020	$ 58.20	$ 7,749.29	$ 1,040.07		151.000	0.02	$ 0.14	272.000	87.01	YES	100	-	$ 6.89	$ -
51.31	07/19/2025	14	$ 12,244.26	211.290	$ 57.95	$ 10,841.92	$ 1,402.34		151.625	59.67	$ 396.00	272.000	87.01	YES	100	-	$ 6.64	$ -
51.31	07/19/2025	15	$ 12,742.17	218.900	$ 58.21	$ 11,232.42	$ 1,509.75		151.208	67.69	$ 466.87	272.000	87.01	YES	100	-	$ 6.90	$ -
51.31	07/19/2025	16	$ 9,292.18	148.390	$ 62.62	$ 7,614.34	$ 1,677.84		99.000	49.39	$ 558.45	272.000	87.01	YES	100	-	$ 11.31	$ -
51.31	07/19/2025	17	$ 9,771.96	140.160	$ 69.72	$ 7,192.03	$ 2,579.93	Brown 3 was on Reserve Shutdown	91.000	49.16	$ 904.89	272.000	87.01	YES	100	-	$ 18.41	$ -
51.31	07/19/2025	18	$ 12,403.59	168.550	$ 73.59	$ 8,648.81	$ 3,754.78	Brown 6 was on outage	100.000	68.55	$ 1,527.09	272.000	87.01	YES	100	-	$ 22.28	$ -
51.31	07/19/2025	19	$ 10,309.71	142.360	$ 72.42	$ 7,304.92	$ 3,004.79		99.000	43.36	$ 915.20	272.000	87.01	YES	100	-	$ 21.11	$ -
51.31	07/19/2025	20	$ 9,403.20	143.670	$ 65.45	$ 7,372.14	$ 2,031.06		99.000	44.67	$ 631.50	272.000	87.01	YES	100	-	$ 14.14	$ -
51.31	07/19/2025	21	$ 14,435.33	241.960	$ 59.66	$ 12,415.69	$ 2,019.64		148.395	93.57	$ 780.99	272.000	87.01	YES	100	-	$ 8.35	$ -
51.31	07/19/2025	22	$ 13,650.81	241.010	$ 56.64	$ 12,366.95	$ 1,283.86		161.009	80.00	$ 426.17	272.000	87.01	YES	100	-	$ 5.33	$ -
51.31	07/20/2025	14	$ 12,624.82	241.300	$ 52.32	$ 12,381.83	$ 242.99		149.000	92.30	$ 92.95	274.000	87.01	YES	100	-	$ 1.01	$ -
51.31	07/20/2025	15	$ 14,754.71	258.900	$ 56.99	$ 13,284.94	$ 1,469.77		149.000	109.90	$ 623.90	274.000	87.01	YES	100	-	$ 5.68	$ -
51.31	07/20/2025	16	$ 16,876.47	283.400	$ 59.55	$ 14,542.10	$ 2,334.37		126.208	157.19	$ 1,294.79	274.000	87.01	YES	100	-	$ 8.24	$ -
51.31	07/20/2025	17	$ 16,772.94	253.100	$ 66.27	$ 12,987.32	$ 3,785.62	Brown 3 was on Reserve Shutdown	87.000	166.10	$ 2,484.36	279.000	87.01	YES	100	-	$ 14.96	$ -
51.31	07/20/2025	18	$ 20,799.71	272.640	$ 76.29	$ 13,989.98	$ 6,809.73	Brown 6 was on outage	94.000	178.64	$ 4,461.89	279.000	87.01	YES	100	-	$ 24.98	$ -
51.31	07/20/2025	19	$ 26,491.23	324.250	$ 81.70	$ 16,638.24	$ 9,852.99		94.833	229.42	$ 6,971.30	279.000	87.01	YES	100	-	$ 30.39	$ -
51.31	07/20/2025	20	$ 33,137.16	411.080	$ 80.61	$ 21,093.75	$ 12,043.41		93.775	317.31	$ 9,296.09	279.000	87.01	YES	100	38.30	$ 29.30	$ 168.33
51.31	07/20/2025	21	$ 28,701.66	459.300	$ 62.49	$ 23,568.06	$ 5,133.60		149.208	310.09	$ 3,465.90	279.000	87.01	YES	100	31.09	$ 11.18	$ 52.13
51.31	07/20/2025	22	$ 21,734.30	419.500	$ 51.81	$ 21,525.80	$ 208.50		157.704	261.80	$ 130.12	279.000	87.01	YES	100	-	$ 0.50	$ -
51.31	07/21/2025	14	$ 18,422.66	356.890	$ 51.62	$ 18,313.10	$ 109.56		168.342	188.55	$ 57.88	282.000	87.01	YES	100	-	$ 0.31	$ -
51.31	07/21/2025	15	$ 14,685.02	276.190	$ 53.17	$ 14,172.14	$ 512.88		160.492	115.70	$ 214.85	282.000	87.01	YES	100	-	$ 1.86	$ -
51.31	07/21/2025	16	$ 16,795.24	287.000	$ 58.52	$ 14,726.83	$ 2,068.41		145.650	141.35	$ 1,018.71	282.000	87.01	YES	100	-	$ 7.21	$ -
51.31	07/21/2025	17	$ 17,274.48	245.900	$ 70.25	$ 12,617.87	$ 4,656.61	Brown 6 was on outage all other units	99.000	146.90	$ 2,781.85	282.000	87.01	YES	100	-	$ 18.94	$ -
51.31	07/21/2025	18	$ 21,218.64	317.220	$ 66.89	$ 16,277.51	$ 4,941.13	online	89.000	228.22	$ 3,554.83	282.000	87.01	YES	100	-	$ 15.58	$ -
51.31	07/21/2025	19	$ 21,727.36	272.000	$ 79.88	$ 13,957.14	$ 7,770.22		59.000	213.00	$ 6,084.77	282.000	87.01	YES	100	-	$ 28.57	$ -
51.31	07/21/2025	20	$ 29,041.99	368.600	$ 78.79	$ 18,913.97	$ 10,128.02		59.000	309.60	$ 8,506.88	282.000	87.01	YES	100	27.60	$ 27.48	$ 113.75
51.31	07/21/2025	21	$ 23,974.90	394.000	$ 60.85	$ 20,217.32	$ 3,757.58		106.334	287.67	$ 2,743.47	282.000	87.01	YES	100	5.67	$ 9.54	$ 8.11
51.31	07/21/2025	22	$ 21,213.71	410.800	$ 51.64	$ 21,079.38	$ 134.33		155.863	254.94	$ 83.36	282.000	87.01	YES	100	-	$ 0.33	$ -
50.88	07/22/2025	13	$ 4,909.73	83.970	$ 58.47	$ 4,271.97	$ 637.76		155.667	-	$ -	274.000	87.01	YES	100	-	$ 7.60	$ -
50.88	07/22/2025	16	$ 14,771.06	281.300	$ 52.51	$ 14,311.14	$ 459.92		145.304	136.00	$ 222.35	284.000	87.01	YES	100	-	$ 1.63	$ -
50.88	07/22/2025	17	$ 14,517.22	227.400	$ 63.84	$ 11,568.98	$ 2,948.25		98.000	129.40	$ 1,677.67	284.000	87.01	YES	100	-	$ 12.97	$ -
50.88	07/22/2025	18	$ 18,588.02	263.100	$ 70.65	$ 13,385.21	$ 5,202.81	Brown 6 was on outage all other units	88.000	175.10	$ 3,462.61	284.000	87.01	YES	100	-	$ 19.78	$ -
50.88	07/22/2025	19	$ 85,701.86	330.310	$ 259.46	$ 16,804.52	$ 68,897.34	online	29.412	300.90	$ 62,762.47	284.000	87.01	YES	100	16.90	$ 208.58	$ 528.70
50.88	07/22/2025	20	$ 37,012.72	398.620	$ 92.85	$ 20,279.79	$ 16,732.93		28.000	370.62	$ 15,557.57	272.000	87.01	YES	100	98.62	$ 41.98	$ 620.97
50.88	07/22/2025	21	$ 24,957.24	388.500	$ 64.24	$ 19,764.94	$ 5,192.30		93.729	294.77	$ 3,939.61	272.000	87.01	YES	100	22.77	$ 13.37	$ 45.65
50.88	07/22/2025	22	$ 28,714.51	482.250	$ 59.54	$ 24,534.47	$ 4,180.04		154.071	328.18	$ 2,844.59	272.000	87.01	YES	100	56.18	$ 8.67	$ 73.04
47.56	07/23/2025	12	$ 16,069.85	280.500	$ 57.29	$ 13,341.42	$ 2,728.43		193.658	86.84	$ 844.71	284.000	87.01	YES	100	-	$ 9.73	$ -
47.56	07/23/2025	13	$ 20,011.01	325.700	$ 61.44	$ 15,491.27	$ 4,519.74		159.700	166.00	$ 2,303.58	282.000	87.01	YES	100	-	$ 13.88	$ -
47.56	07/23/2025	14	$ 23,343.98	323.100	$ 72.25	$ 15,367.61	$ 7,976.37		112.000	211.10	$ 5,211.43	274.000	87.01	YES	100	-	$ 24.69	$ -
47.56	07/23/2025	15	$ 18,635.18	249.300	$ 74.75	$ 11,857.46	$ 6,777.72		72.267	177.03	$ 4,813.00	269.000	87.01	YES	100	-	$ 27.19	$ -
47.56	07/23/2025	16	$ 16,848.34	206.500	$ 81.59	$ 9,821.76	$ 7,026.58		67.150	139.35	$ 4,741.67	269.000	87.01	YES	100	-	$ 34.03	$ -
47.56	07/23/2025	17	$ 21,499.41	217.100	$ 99.03	$ 10,325.93	$ 11,173.48	Brown 6 was on outage all other units	58.767	158.33	$ 8,148.92	183.000	87.01	YES	100	-	$ 51.47	$ -
47.56	07/23/2025	18	$ 24,900.03	220.980	$ 112.68	$ 10,510.47	$ 14,389.56	online	58.417	162.56	$ 10,585.62	93.000	87.01	YES	100	69.56	$ 65.12	$ 679.46
47.56	07/23/2025	19	$ 48,889.27	452.860	$ 107.96	$ 21,539.38	$ 27,349.89		54.792	398.07	$ 24,040.80	269.000	87.01	YES	100	129.07	$ 60.39	$ 1,169.23
47.56	07/23/2025	20	$ 62,122.19	485.190	$ 128.04	$ 23,077.09	$ 39,045.10		50.050	435.14	$ 35,017.38	269.000	87.01	YES	100	166.14	$ 80.47	$ 2,005.49
47.56	07/23/2025	21	$ 36,588.02	389.400	$ 93.96	$ 18,521.03	$ 18,066.99		60.970	328.43	$ 15,238.16	269.000	87.01	YES	100	59.43	$ 46.40	$ 413.61
47.56	07/23/2025	22	$ 30,295.39	393.600	$ 76.97	$ 18,720.80	$ 11,574.59		109.796	283.80	$ 8,345.82	268.000	87.01	YES	100	15.80	$ 29.41	$ 69.71
47.56	07/23/2025	23	$ 23,831.59	409.900	$ 58.14	$ 19,496.07	$ 4,335.52		176.934	232.97	$ 2,464.08	269.000	87.01	YES	100	-	$ 10.58	$ -
47.56	07/23/2025	24	$ 17,066.95	358.700	$ 47.58	$ 17,060.85	$ 6.10		175.392	183.31	$ 3.12	269.000	87.01	YES	100	-	$ 0.02	$ -
45.88	07/24/2025	9	$ 10,376.96	222.300	$ 46.68	$ 10,198.01	$ 178.95		188.384	33.92	$ 27.30	274.000	87.01	YES	100	-	$ 0.80	$ -
45.88	07/24/2025	10	$ 11,132.59	221.500	$ 50.26	$ 10,161.31	$ 971.28		162.521	58.98	$ 258.62	274.000	87.01	YES	100	-	$ 4.39	$ -
45.88	07/24/2025	11	$ 12,607.45	205.400	$ 61.38	$ 9,422.73	$ 3,184.73		95.471	109.93	$ 1,704.45	274.000	87.01	YES	100	-	$ 15.50	$ -
45.88	07/24/2025	12	$ 19,028.68	222.280	$ 85.61	$ 10,197.10	$ 8,831.59		41.875	180.41	$ 7,167.82	268.000	87.01	YES	100	-	$ 39.73	$ -
45.88	07/24/2025	13	$ 21,192.80	202.260	$ 104.78	$ 9,278.68	$ 11,914.12		8.183	194.08	$ 11,432.10	268.000	87.01	YES	100	-	$ 58.90	$ -
45.88	07/24/2025	14	$ 37,930.63	295.940	$ 128.17	$ 13,576.25	$ 24,354.38		22.000	273.94	$ 22,543.89	269.000	87.01	YES	100	4.94	$ 82.30	$ 60.98
45.88	07/24/2025	15	$ 38,971.88	283.040	$ 137.69	$ 12,984.46	$ 25,987.42		9.000	274.04	$ 25,161.08	269.000	87.01	YES	100	5.04	$ 91.82	$ 69.41
45.88	07/24/2025	16	$ 41,320.76	289.580	$ 142.69	$ 13,284.48	$ 28,036.28	Brown 6 was on outage all other units	57.000	232.58	$ 22,517.71	274.000	87.01	YES	100	-	$ 96.82	$ -
45.88	07/24/2025	17	$ 53,022.04	345.870	$ 153.30	$ 15,866.79	$ 37,155.25	online	57.000	288.87	$ 31,032.00	274.000	87.01	YES	100	14.87	$ 107.43	$ 239.61
45.88	07/24/2025	18	$ 61,749.22	380.680	$ 162.21	$ 17,463.70	$ 44,285.53		58.000	322.68	$ 37,538.23	274.000	87.01	YES	100	48.68	$ 116.33	$ 849.46
45.88	07/24/2025	19	$ 95,709.31	451.030	$ 212.20	$ 20,691.00	$ 75,018.31		39.987	411.04	$ 68,367.41	274.000	87.01	YES	100	137.04	$ 166.33	$ 3,419.09
45.88	07/24/2025	20	$ 104,811.01	533.400	$ 196.50	$ 24,469.73	$ 80,341.29		51.000	482.40	$ 72,659.61	274.000	87.01	YES	100	208.40	$ 150.62	$ 4,708.42
45.88	07/24/2025	21	$ 67,890.06	532.690	$ 127.45	$ 24,437.15	$ 43,452.91		42.692	490.00	$ 39,970.41	274.000	87.01	YES	100	216.00	$ 81.57	$ 2,642.93
45.88	07/24/2025	22	$ 53,039.28	504.420	$ 105.15	$ 23,140.27	$ 29,899.01		62.296	442.12	$ 26,206.48	274.000	87.01	YES	100	168.12	$ 59.27	$ 1,494.81
45.88	07/24/2025	23	$ 26,548.64	333.400	$ 79.63	$ 15,294.73	$ 11,253.92		68.827	264.57	$ 8,930.66	274.000	87.01	YES	100	-	$ 33.75	$ -

CenterPoint Energy Indiana South
Market Settlements Group
Purchased Power Over Benchmark Explanations Cause No. 38708 FAC 149

S55's through 07/31

Jul Benchmark Costs	Trade Date	HE	Cost of Purchased Power	Purchases Volume	Price	Purchases Volume @ Benchmark $	Amount Over Benchmark $	Reason for Purchasing Power	Available Capacity of Units Not Selected	MISO Economic Dispatch / Purchased MWs above Capacity	Purchase Power Costs at Risk	Test for Outages and Derates: MWs Out of Service	11% of Summer Rated Capacity	Are Unit MWs Out of Service > 11% Summer Capacity?	Recoverable @ 0%, 85%, or 100%	MWs Subject to 85% 15%	Over Benchmark Price	Total Unrecoverable Dollars
45.88	07/24/2025	24	$ 19,577.60	280.000	$ 69.92	$ 12,845.00	$ 6,732.60		70.792	209.21	$ 5,030.41	274.000	87.01	YES	100	-	$ 24.05	$ -
46.44	07/25/2025	1	$ 20,050.11	356.700	$ 56.21	$ 16,564.43	$ 3,485.68		135.409	221.29	$ 2,162.46	269.000	87.01	YES	100	-	$ 9.77	$ -
46.44	07/25/2025	8	$ 11,889.68	251.900	$ 47.20	$ 11,697.73	$ 191.95		150.608	101.29	$ 77.18	269.000	87.01	YES	100	-	$ 0.76	$ -
46.44	07/25/2025	9	$ 12,340.73	235.600	$ 52.38	$ 10,940.79	$ 1,399.94		156.925	78.68	$ 467.49	269.000	87.01	YES	100	-	$ 5.94	$ -
46.44	07/25/2025	10	$ 12,888.04	231.300	$ 55.72	$ 10,741.11	$ 2,146.93		140.000	91.30	$ 847.45	269.000	87.01	YES	100	-	$ 9.28	$ -
46.44	07/25/2025	11	$ 13,294.82	213.400	$ 62.30	$ 9,909.87	$ 3,384.95		99.667	113.73	$ 1,804.03	269.000	87.01	YES	100	-	$ 15.86	$ -
46.44	07/25/2025	12	$ 16,882.34	239.840	$ 70.39	$ 11,137.69	$ 5,744.65		98.000	141.84	$ 3,397.35	269.000	87.01	YES	100	-	$ 23.95	$ -
46.44	07/25/2025	13	$ 20,619.08	279.240	$ 73.84	$ 12,967.35	$ 7,651.73		98.000	181.24	$ 4,966.34	269.000	87.01	YES	100	-	$ 27.40	$ -
46.44	07/25/2025	14	$ 23,168.33	285.500	$ 81.15	$ 13,258.05	$ 9,910.28		59.000	226.50	$ 7,862.27	269.000	87.01	YES	100	-	$ 34.71	$ -
46.44	07/25/2025	15	$ 24,303.91	261.220	$ 93.04	$ 12,130.53	$ 12,173.38	*Brown 6 was on outage all other units online*	50.000	211.22	$ 9,843.28	269.000	87.01	YES	100	-	$ 46.60	$ -
46.44	07/25/2025	16	$ 24,747.22	251.310	$ 98.47	$ 11,670.33	$ 13,076.89		37.975	213.34	$ 11,100.86	268.000	87.01	YES	100	-	$ 52.03	$ -
46.44	07/25/2025	17	$ 17,741.56	145.530	$ 121.91	$ 6,758.12	$ 10,983.44		17.667	127.86	$ 9,650.07	177.000	87.01	YES	100	-	$ 75.47	$ -
46.44	07/25/2025	18	$ 10,559.56	82.400	$ 128.15	$ 3,826.49	$ 6,733.07		40.708	41.69	$ 3,406.74	53.000	87.01	NO	85	41.69	$ 81.71	$ 511.01
46.44	07/25/2025	19	$ 22,295.98	169.900	$ 131.23	$ 7,889.82	$ 14,406.16		57.000	112.90	$ 9,573.02	47.000	87.01	NO	85	112.90	$ 84.79	$ 1,435.95
46.44	07/25/2025	20	$ 24,348.54	240.100	$ 101.41	$ 11,149.76	$ 13,198.78		57.000	183.10	$ 10,065.37	45.000	87.01	NO	85	183.10	$ 54.97	$ 1,509.81
46.44	07/25/2025	21	$ 17,431.05	227.500	$ 76.62	$ 10,564.65	$ 6,866.41		57.000	170.50	$ 5,146.03	42.000	87.01	NO	85	170.50	$ 30.18	$ 771.90
46.44	07/25/2025	22	$ 16,062.53	248.300	$ 64.69	$ 11,530.56	$ 4,531.97		90.604	157.70	$ 2,878.27	74.000	87.01	NO	85	157.70	$ 18.25	$ 431.74
46.44	07/25/2025	23	$ 20,159.66	428.200	$ 47.08	$ 19,884.75	$ 274.91		159.967	268.23	$ 172.21	259.000	87.01	YES	100	9.23	$ 0.64	$ 0.89
46.13	07/26/2025	1	$ 1,295.75	22.300	$ 58.11	$ 1,028.59	$ 267.16		158.476	-	$ -	264.000	87.01	YES	100	-	$ 11.98	$ -
46.13	07/26/2025	10	$ 2,895.40	36.870	$ 78.53	$ 1,700.63	$ 1,194.77		9.467	27.40	$ 887.99	253.000	87.01	YES	100	-	$ 32.40	$ -
46.13	07/26/2025	12	$ 12,426.09	235.090	$ 52.86	$ 10,843.53	$ 1,582.56		3.742	231.35	$ 1,557.37	253.000	87.01	YES	100	-	$ 6.73	$ -
46.13	07/26/2025	13	$ 11,701.45	218.270	$ 53.61	$ 10,067.70	$ 1,633.75		0.000	218.27	$ 1,633.75	253.000	87.01	YES	100	-	$ 7.48	$ -
46.13	07/26/2025	14	$ 11,327.40	195.300	$ 58.00	$ 9,008.21	$ 2,319.19		91.000	104.30	$ 1,238.56	264.000	87.01	YES	100	-	$ 11.88	$ -
46.13	07/26/2025	15	$ 11,293.38	188.380	$ 59.95	$ 8,689.03	$ 2,604.35		75.000	113.38	$ 1,567.48	264.000	87.01	YES	100	-	$ 13.82	$ -
46.13	07/26/2025	16	$ 14,751.04	246.060	$ 59.95	$ 11,349.52	$ 3,401.52	*Brown 6 was on outage all other units online*	87.000	159.06	$ 2,198.84	264.000	87.01	YES	100	-	$ 13.82	$ -
46.13	07/26/2025	17	$ 14,561.51	199.500	$ 72.99	$ 9,201.94	$ 5,359.57		97.000	102.50	$ 2,753.67	264.000	87.01	YES	100	-	$ 26.87	$ -
46.13	07/26/2025	18	$ 17,092.42	235.340	$ 72.63	$ 10,855.06	$ 6,237.36		56.000	179.34	$ 4,753.16	264.000	87.01	YES	100	-	$ 26.50	$ -
46.13	07/26/2025	19	$ 20,599.68	238.920	$ 86.22	$ 11,020.19	$ 9,579.50		52.000	186.92	$ 7,494.56	264.000	87.01	YES	100	-	$ 40.09	$ -
46.13	07/26/2025	20	$ 22,722.21	318.060	$ 71.44	$ 14,670.52	$ 8,051.69		51.000	267.06	$ 6,760.63	264.000	87.01	YES	100	3.06	$ 25.32	$ 11.62
46.13	07/26/2025	21	$ 22,360.34	347.480	$ 64.35	$ 16,027.52	$ 6,332.83		82.975	264.51	$ 4,820.61	264.000	87.01	YES	100	0.50	$ 18.23	$ 1.38
46.13	07/26/2025	22	$ 21,925.49	400.780	$ 54.71	$ 18,485.98	$ 3,439.51		158.583	242.20	$ 2,078.55	264.000	87.01	YES	100	-	$ 8.58	$ -
46.13	07/27/2025	12	$ 52,032.70	602.880	$ 86.31	$ 27,807.84	$ 24,224.86		149.000	453.88	$ 18,237.76	612.000	87.01	YES	100	-	$ 40.18	$ -
46.13	07/27/2025	13	$ 33,938.08	627.860	$ 54.05	$ 28,960.04	$ 4,978.04		149.000	478.86	$ 3,796.68	612.000	87.01	YES	100	-	$ 7.93	$ -
46.13	07/27/2025	14	$ 38,738.99	622.220	$ 62.26	$ 28,699.90	$ 10,039.09		149.000	473.22	$ 7,635.08	612.000	87.01	YES	100	-	$ 16.13	$ -
46.13	07/27/2025	15	$ 64,196.33	597.520	$ 107.44	$ 27,560.61	$ 36,635.72		95.000	502.52	$ 30,810.99	612.000	87.01	YES	100	-	$ 61.31	$ -
46.13	07/27/2025	16	$ 36,259.15	537.420	$ 67.47	$ 24,788.50	$ 11,470.65		41.000	496.42	$ 10,595.55	612.000	87.01	YES	100	-	$ 21.34	$ -
46.13	07/27/2025	17	$ 32,110.69	513.060	$ 62.59	$ 23,664.89	$ 8,445.80	*Brown 6 Culley 2 and Culley 3 were on outage all other units online*	44.000	469.06	$ 7,721.49	612.000	87.01	YES	100	-	$ 16.46	$ -
46.13	07/27/2025	18	$ 38,597.98	566.380	$ 68.15	$ 26,124.28	$ 12,473.70		44.000	522.38	$ 11,504.67	612.000	87.01	YES	100	-	$ 22.02	$ -
46.13	07/27/2025	19	$ 47,806.22	647.470	$ 73.84	$ 29,864.55	$ 17,941.67		46.163	601.31	$ 16,662.47	604.000	87.01	YES	100	-	$ 27.71	$ -
46.13	07/27/2025	20	$ 48,472.55	627.460	$ 77.25	$ 28,941.59	$ 19,530.96		39.000	588.46	$ 18,317.00	588.000	87.01	YES	100	0.46	$ 31.13	$ 2.15
46.13	07/27/2025	21	$ 38,215.70	660.440	$ 57.86	$ 30,462.80	$ 7,752.90		88.728	571.71	$ 6,711.33	564.000	87.01	YES	100	7.71	$ 11.74	$ 13.58
46.13	07/27/2025	22	$ 21,756.15	397.300	$ 54.76	$ 18,325.46	$ 3,430.69		132.754	264.55	$ 2,284.36	562.000	87.01	YES	100	-	$ 8.64	$ -
46.13	07/28/2025	9	$ 11,797.24	231.500	$ 50.96	$ 10,677.94	$ 1,119.30		431.000	-	$ -	264.000	87.01	YES	100	-	$ 4.84	$ -
46.13	07/28/2025	10	$ 13,160.45	230.400	$ 57.12	$ 10,627.20	$ 2,533.25		415.050	-	$ -	264.000	87.01	YES	100	-	$ 11.00	$ -
46.13	07/28/2025	11	$ 16,206.63	221.100	$ 73.30	$ 10,198.24	$ 6,008.39		341.075	-	$ -	264.000	87.01	YES	100	-	$ 27.18	$ -
46.13	07/28/2025	12	$ 39,926.04	481.590	$ 82.90	$ 22,213.34	$ 17,712.70		320.725	160.87	$ 5,916.55	264.000	87.01	YES	100	-	$ 36.78	$ -
46.13	07/28/2025	13	$ 54,480.28	472.180	$ 115.38	$ 21,779.30	$ 32,700.98		301.000	171.18	$ 11,855.13	264.000	87.01	YES	100	-	$ 69.26	$ -
46.13	07/28/2025	14	$ 83,732.59	500.490	$ 167.30	$ 23,085.10	$ 60,647.49		277.121	223.37	$ 27,067.01	264.000	87.01	YES	100	-	$ 121.18	$ -
46.13	07/28/2025	15	$ 72,905.66	567.300	$ 128.51	$ 26,166.71	$ 46,738.95		311.000	256.30	$ 21,116.15	264.000	87.01	YES	100	-	$ 82.39	$ -
46.13	07/28/2025	16	$ 77,634.07	634.800	$ 122.30	$ 29,280.15	$ 48,353.92	*Culley 3 and Brown 6 were returning from Outage all other units online*	327.000	307.80	$ 23,445.71	264.000	87.01	YES	100	43.80	$ 76.17	$ 500.45
46.13	07/28/2025	17	$ 90,958.02	562.380	$ 161.74	$ 25,939.78	$ 65,018.24		325.000	237.38	$ 27,444.13	155.000	87.01	YES	100	82.38	$ 115.61	$ 1,428.63
46.13	07/28/2025	18	$ 102,546.77	458.130	$ 223.84	$ 21,131.25	$ 81,415.52		323.000	135.13	$ 24,014.32	47.000	87.01	NO	85	135.13	$ 177.71	$ 3,602.15
46.13	07/28/2025	19	$ 277,875.31	398.500	$ 697.30	$ 18,380.81	$ 259,494.50		277.188	121.31	$ 78,995.73	48.000	87.01	NO	85	121.31	$ 651.18	$ 11,849.36
46.13	07/28/2025	20	$ 152,708.81	460.150	$ 331.87	$ 21,224.42	$ 131,484.39		270.312	189.84	$ 54,244.78	44.000	87.01	NO	85	189.84	$ 285.74	$ 8,136.72
46.13	07/28/2025	21	$ 65,205.63	387.000	$ 168.49	$ 17,850.38	$ 47,355.26		272.950	114.05	$ 13,955.73	44.000	87.01	NO	85	114.05	$ 122.37	$ 2,093.36
46.13	07/28/2025	22	$ 46,272.12	391.010	$ 118.34	$ 18,035.34	$ 28,236.78		293.117	97.89	$ 7,069.34	42.000	87.01	NO	85	97.89	$ 72.21	$ 1,060.40
46.13	07/28/2025	23	$ 22,634.32	322.610	$ 70.16	$ 14,880.39	$ 7,753.93		283.859	38.75	$ 931.38	36.000	87.01	NO	85	38.75	$ 24.04	$ 139.71
46.13	07/28/2025	24	$ 16,483.71	284.300	$ 57.98	$ 13,113.34	$ 3,370.37		290.217	-	$ -	36.000	87.01	NO	85	-	$ 11.85	$ -
46.56	07/29/2025	1	$ 24,457.93	506.900	$ 48.25	$ 23,602.78	$ 855.15		172.948	333.95	$ 563.38	388.000	87.01	YES	100	-	$ 1.69	$ -
46.56	07/29/2025	9	$ 19,299.97	341.230	$ 56.56	$ 15,888.69	$ 3,411.28		380.287	-	$ -	193.000	87.01	YES	100	-	$ 10.00	$ -
46.56	07/29/2025	10	$ 20,255.40	334.800	$ 60.50	$ 15,589.29	$ 4,666.11		312.512	22.29	$ 310.63	213.000	87.01	YES	100	-	$ 13.94	$ -
46.56	07/29/2025	11	$ 27,645.50	393.530	$ 70.25	$ 18,323.94	$ 9,321.56		265.867	127.66	$ 3,023.96	213.000	87.01	YES	100	-	$ 23.69	$ -
46.56	07/29/2025	12	$ 35,700.56	342.550	$ 104.22	$ 15,950.16	$ 19,750.40		245.971	96.58	$ 5,568.46	213.000	87.01	YES	100	-	$ 57.66	$ -
46.56	07/29/2025	13	$ 38,848.99	291.200	$ 133.41	$ 13,559.15	$ 25,289.84		187.780	103.42	$ 8,981.72	213.000	87.01	YES	100	-	$ 86.85	$ -
46.56	07/29/2025	14	$ 21,780.96	135.800	$ 160.39	$ 6,323.26	$ 15,457.70		6.408	129.39	$ 14,728.30	213.000	87.01	YES	100	-	$ 113.83	$ -
46.56	07/29/2025	15	$ 31,806.57	159.200	$ 199.79	$ 7,412.83	$ 24,393.74		0.730	158.47	$ 24,281.88	213.000	87.01	YES	100	-	$ 153.23	$ -
46.56	07/29/2025	16	$ 57,265.77	242.200	$ 236.44	$ 11,277.56	$ 45,988.21	*Culley 3 was derated all other units online*	43.148	199.05	$ 37,795.40	213.000	87.01	YES	100	-	$ 189.88	$ -
46.56	07/29/2025	17	$ 76,723.06	270.800	$ 283.32	$ 12,609.26	$ 64,113.80		39.208	231.59	$ 54,831.03	213.000	87.01	YES	100	18.59	$ 236.76	$ 660.27
46.56	07/29/2025	18	$ 83,233.95	269.200	$ 309.19	$ 12,534.76	$ 70,699.19		23.175	246.03	$ 64,612.81	213.000	87.01	YES	100	33.03	$ 262.63	$ 1,300.99

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S55's through 07/31

Jul Benchmark Costs	Trade Date	HE	Cost of Purchased Power	Purchases Volume	Price	Purchases Volume @ Benchmark $	Amount Over Benchmark $	Reason for Purchasing Power	Available Capacity of Units Not Selected	MISO Economic Dispatch / Purchased MWs above Capacity	Purchase Power Costs at Risk	Test for Outages and Derates: MWs Out of Service	11% of Summer Rated Capacity	Are Unit MWs Out of Service > 11% Summer Capacity?	Recoverable @ 0%, 85%, or 100%	MWs Subject to 85% 15%	Over Benchmark Price	Total Unrecoverable Dollars
46.56	07/29/2025	19	$ 134,052.70	310.300	$ 432.01	$ 14,448.50	$ 119,604.20		12.479	297.82	$ 114,794.21	213.000	87.01	YES	100	84.82	$ 385.45	$ 4,904.10
46.56	07/29/2025	20	$ 110,301.95	370.900	$ 297.39	$ 17,270.22	$ 93,031.73		2.905	368.00	$ 92,303.08	212.000	87.01	YES	100	156.00	$ 250.83	$ 5,869.16
46.56	07/29/2025	21	$ 57,972.60	374.500	$ 154.80	$ 17,437.84	$ 40,534.76		16.334	358.17	$ 38,766.81	213.000	87.01	YES	100	145.17	$ 108.24	$ 2,356.85
46.56	07/29/2025	22	$ 59,778.63	527.800	$ 113.26	$ 24,575.95	$ 35,202.68		208.014	319.79	$ 21,328.77	213.000	87.01	YES	100	106.79	$ 66.70	$ 1,068.35
46.56	07/29/2025	23	$ 39,362.79	572.300	$ 68.78	$ 26,648.00	$ 12,714.79		315.088	257.21	$ 5,714.48	213.000	87.01	YES	100	44.21	$ 22.22	$ 147.34
46.56	07/29/2025	24	$ 28,728.94	559.800	$ 51.32	$ 26,065.97	$ 2,662.97		360.290	199.51	$ 949.07	213.000	87.01	YES	100	-	$ 4.76	$ -
45.94	07/30/2025	1	$ 29,357.27	589.000	$ 49.84	$ 27,057.48	$ 2,299.79		374.373	214.63	$ 838.02	218.000	87.01	YES	100	-	$ 3.90	$ -
45.94	07/30/2025	5	$ 6,291.43	97.700	$ 64.40	$ 4,488.14	$ 1,803.29		387.258	-	$ -	218.000	87.01	YES	100	-	$ 18.46	$ -
45.94	07/30/2025	6	$ 9,067.15	68.800	$ 131.79	$ 3,160.53	$ 5,906.62		368.900	-	$ -	223.000	87.01	YES	100	-	$ 85.85	$ -
45.94	07/30/2025	7	$ 20,881.81	448.300	$ 46.58	$ 20,594.01	$ 287.80		364.171	84.13	$ 54.01	223.000	87.01	YES	100	-	$ 0.64	$ -
45.94	07/30/2025	8	$ 17,326.67	363.700	$ 47.64	$ 16,707.65	$ 619.02		353.083	10.62	$ 18.07	218.000	87.01	YES	100	-	$ 1.70	$ -
45.94	07/30/2025	9	$ 7,690.76	148.700	$ 51.72	$ 6,830.98	$ 859.78		228.616	-	$ -	218.000	87.01	YES	100	-	$ 5.78	$ -
45.94	07/30/2025	10	$ 9,679.57	162.200	$ 59.68	$ 7,451.14	$ 2,228.43		150.246	11.95	$ 164.23	218.000	87.01	YES	100	-	$ 13.74	$ -
45.94	07/30/2025	11	$ 12,948.09	195.790	$ 66.13	$ 8,994.20	$ 3,953.89		98.696	97.09	$ 1,960.77	218.000	87.01	YES	100	-	$ 20.19	$ -
45.94	07/30/2025	12	$ 15,997.62	165.490	$ 96.67	$ 7,602.28	$ 8,395.34		45.654	119.84	$ 6,079.30	218.000	87.01	YES	100	-	$ 50.73	$ -
45.94	07/30/2025	13	$ 16,724.40	178.360	$ 93.77	$ 8,193.50	$ 8,530.90		43.611	134.75	$ 6,445.00	218.000	87.01	YES	100	-	$ 47.83	$ -
45.94	07/30/2025	14	$ 19,385.70	170.250	$ 113.87	$ 7,820.94	$ 11,564.76	*Culley 3 was derated all other units online*	10.362	159.89	$ 10,860.88	218.000	87.01	YES	100	-	$ 67.93	$ -
45.94	07/30/2025	15	$ 18,259.91	153.200	$ 119.19	$ 7,037.70	$ 11,222.21		6.091	147.11	$ 10,776.03	218.000	87.01	YES	100	-	$ 73.25	$ -
45.94	07/30/2025	16	$ 18,647.56	160.720	$ 116.03	$ 7,383.16	$ 11,264.40		18.333	142.39	$ 9,979.50	218.000	87.01	YES	100	-	$ 70.09	$ -
45.94	07/30/2025	17	$ 25,187.14	243.780	$ 103.32	$ 11,198.77	$ 13,988.37		45.500	198.28	$ 11,377.53	218.000	87.01	YES	100	-	$ 57.38	$ -
45.94	07/30/2025	18	$ 26,203.47	218.360	$ 120.00	$ 10,031.02	$ 16,172.45		23.588	194.77	$ 14,425.44	218.000	87.01	YES	100	-	$ 74.06	$ -
45.94	07/30/2025	19	$ 37,064.90	322.860	$ 114.80	$ 14,831.54	$ 22,233.36		37.092	285.77	$ 19,679.06	218.000	87.01	YES	100	67.77	$ 68.86	$ 700.01
45.94	07/30/2025	20	$ 38,684.94	455.900	$ 84.85	$ 20,943.13	$ 17,741.81		81.750	374.15	$ 14,560.42	218.000	87.01	YES	100	156.15	$ 38.92	$ 911.51
45.94	07/30/2025	21	$ 36,393.28	480.230	$ 75.78	$ 22,060.81	$ 14,332.47		114.566	365.66	$ 10,913.25	218.000	87.01	YES	100	147.66	$ 29.85	$ 661.06
45.94	07/30/2025	22	$ 23,838.19	397.900	$ 59.91	$ 18,278.73	$ 5,559.46		214.896	183.00	$ 2,556.93	218.000	87.01	YES	100	-	$ 13.97	$ -
45.94	07/30/2025	23	$ 1,585.89	26.300	$ 60.30	$ 1,208.17	$ 377.72		306.504	-	$ -	218.000	87.01	YES	100	-	$ 14.36	$ -
45.94	07/30/2025	24	$ 5,134.90	86.060	$ 59.67	$ 3,953.42	$ 1,181.48		384.173	-	$ -	218.000	87.01	YES	100	-	$ 13.73	$ -
44.69	07/31/2025	8	$ 467.38	6.140	$ 76.12	$ 274.38	$ 193.00		379.108	-	$ -	219.000	87.01	YES	100	-	$ 31.43	$ -
44.69	07/31/2025	10	$ 22,675.74	423.460	$ 53.55	$ 18,923.58	$ 3,752.16		389.924	33.54	$ 297.15	219.000	87.01	YES	100	-	$ 8.86	$ -
44.69	07/31/2025	11	$ 15,705.73	285.570	$ 55.00	$ 12,761.55	$ 2,944.18		230.682	54.89	$ 565.89	219.000	87.01	YES	100	-	$ 10.31	$ -
44.69	07/31/2025	12	$ 13,321.15	262.110	$ 50.82	$ 11,713.17	$ 1,607.98		167.179	94.93	$ 582.38	219.000	87.01	YES	100	-	$ 6.13	$ -
44.69	07/31/2025	13	$ 13,946.91	251.870	$ 55.37	$ 11,255.57	$ 2,691.34		147.150	104.72	$ 1,118.98	219.000	87.01	YES	100	-	$ 10.69	$ -
44.69	07/31/2025	14	$ 9,893.57	157.800	$ 62.70	$ 7,051.77	$ 2,841.80		121.387	36.41	$ 655.76	219.000	87.01	YES	100	-	$ 18.01	$ -
44.69	07/31/2025	15	$ 9,660.88	157.600	$ 61.30	$ 7,042.83	$ 2,618.05	*Culley 3 was derated all other units online*	154.404	3.20	$ 53.09	219.000	87.01	YES	100	-	$ 16.61	$ -
44.69	07/31/2025	16	$ 6,143.85	101.200	$ 60.71	$ 4,522.43	$ 1,621.42		144.116	-	$ -	219.000	87.01	YES	100	-	$ 16.02	$ -
44.69	07/31/2025	17	$ 6,223.50	97.900	$ 63.57	$ 4,374.96	$ 1,848.54		179.570	-	$ -	219.000	87.01	YES	100	-	$ 18.88	$ -
44.69	07/31/2025	18	$ 10,002.34	139.600	$ 71.65	$ 6,238.44	$ 3,763.90		188.868	-	$ -	219.000	87.01	YES	100	-	$ 26.96	$ -
44.69	07/31/2025	19	$ 14,963.10	180.300	$ 82.99	$ 8,057.25	$ 6,905.85		184.130	-	$ -	219.000	87.01	YES	100	-	$ 38.30	$ -
44.69	07/31/2025	20	$ 19,416.74	252.100	$ 77.02	$ 11,265.84	$ 8,150.90		228.223	23.88	$ 771.99	219.000	87.01	YES	100	-	$ 32.33	$ -
44.69	07/31/2025	21	$ 14,657.89	305.500	$ 47.98	$ 13,652.18	$ 1,005.71		262.102	43.40	$ 142.87	219.000	87.01	YES	100	-	$ 3.29	$ -
44.69	07/31/2025	22	$ 25,205.33	503.000	$ 50.11	$ 22,478.06	$ 2,727.27		391.001	112.00	$ 607.26	219.000	87.01	YES	100	-	$ 5.42	$ -
Total			**$ 7,756,145.98**	**87,271.400**		**$ 4,151,912.83**	**$ 3,604,233.44**		**59,548.785**	**43,824.159**	**$ 2,279,671.76**	**68,468.000**				**6,503.336**		**$ 82,529.06**

CenterPoint Energy Indiana South
Market Settlements Group
Purchased Power Over Benchmark Explanations Cause No. 38708 FAC 149

S55's through 08/31

Aug Benchmark Costs	Trade Date	HE	Cost of Purchased Power	Purchases Volume	Price	Purchases Volume @ Benchmark $	Amount Over Benchmark $	Reason for Purchasing Power	Available Capacity of Units Not Selected	MISO Economic Dispatch / Purchased MWs above Capacity	Purchase Power Costs at Risk	Test for Outages and Derates: MWs Out of Service	Test for Outages and Derates: 11% of Summer Rated Capacity 791	Test for Outages and Derates: Are Unit MWs Out of Service > 11% Summer Capacity?	Recoverable @ 0%, 85%, or 100%	MWs Subject to 85% 15%	Over Benchmark Price	Total Unrecoverable Dollars
44.38	08/01/2025	14	$ 4,534.91	99.800	$ 45.44	$ 4,428.63	$ 106.29		230.658	-	$ -	302.000	87.01	YES	100	-	$ 1.06	$ -
44.38	08/01/2025	15	$ 5,452.87	101.600	$ 53.67	$ 4,508.50	$ 944.37		228.362	-	$ -	302.000	87.01	YES	100	-	$ 9.29	$ -
44.38	08/01/2025	16	$ 5,678.43	97.300	$ 58.36	$ 4,317.69	$ 1,360.74		302.762	-	$ -	227.000	87.01	YES	100	-	$ 13.99	$ -
44.38	08/01/2025	17	$ 6,051.15	104.800	$ 57.74	$ 4,650.50	$ 1,400.65	*Brown 3 and Brown 4 were on Reserve Shutdown*	301.183	-	$ -	227.000	87.01	YES	100	-	$ 13.36	$ -
44.38	08/01/2025	18	$ 9,301.91	161.100	$ 57.74	$ 7,148.81	$ 2,153.10		276.262	-	$ -	227.000	87.01	YES	100	-	$ 13.36	$ -
44.38	08/01/2025	19	$ 19,107.35	297.070	$ 64.32	$ 13,182.48	$ 5,924.87		236.844	60.23	$ 1,201.17	227.000	87.01	YES	100	-	$ 19.94	$ -
44.38	08/01/2025	20	$ 21,653.98	298.100	$ 72.64	$ 13,228.19	$ 8,425.79		301.179	-	$ -	227.000	87.01	YES	100	-	$ 28.26	$ -
44.38	08/01/2025	21	$ 13,741.35	272.700	$ 50.39	$ 12,101.06	$ 1,640.29		289.891	-	$ -	227.000	87.01	YES	100	-	$ 6.01	$ -
44.88	08/02/2025	19	$ 11,533.15	244.450	$ 47.18	$ 10,969.69	$ 563.46	*Brown 3 Brown 4 Brown 6 and Culley 2 were on Reserve Shutdown*	451.583	-	$ -	44.000	87.01	NO	85	-	$ 2.30	$ -
44.88	08/03/2025	18	$ 2,907.92	57.800	$ 50.31	$ 2,593.78	$ 314.15		305.017	-	$ -	42.000	87.01	NO	85	-	$ 5.44	$ -
44.88	08/03/2025	19	$ 6,198.50	101.200	$ 61.25	$ 4,541.35	$ 1,657.15	*Brown 3 Brown 4 and Culley 2 were on Reserve Shutdown*	304.241	-	$ -	42.000	87.01	NO	85	-	$ 16.38	$ -
44.88	08/03/2025	20	$ 9,314.63	178.100	$ 52.30	$ 7,992.24	$ 1,322.39		415.942	-	$ -	42.000	87.01	NO	85	-	$ 7.43	$ -
44.88	08/03/2025	21	$ 78,146.77	315.620	$ 247.60	$ 14,163.45	$ 63,983.32		711.317	-	$ -	42.000	87.01	NO	85	-	$ 202.72	$ -
44.88	08/03/2025	22	$ 16,340.04	303.240	$ 53.88	$ 13,607.90	$ 2,732.15		449.000	-	$ -	312.000	87.01	YES	100	-	$ 9.01	$ -
44.88	08/04/2025	12	$ 9,122.48	194.800	$ 46.83	$ 8,741.65	$ 380.83		376.950	-	$ -	312.000	87.01	YES	100	-	$ 1.95	$ -
44.88	08/04/2025	14	$ 26,040.67	358.440	$ 72.65	$ 16,085.00	$ 9,955.68		158.088	200.35	$ 5,564.78	312.000	87.01	YES	100	-	$ 27.78	$ -
44.88	08/04/2025	19	$ 2,439.39	31.000	$ 78.69	$ 1,391.13	$ 1,048.27		127.626	-	$ -	312.000	87.01	YES	100	-	$ 33.82	$ -
44.88	08/04/2025	20	$ 18,954.32	374.290	$ 50.64	$ 16,796.26	$ 2,158.06	*Brown 3 was on Reserve Shutdown and Culley 3 was on outage*	111.560	262.73	$ 1,514.83	312.000	87.01	YES	100	-	$ 5.77	$ -
44.88	08/04/2025	21	$ 24,365.74	387.480	$ 62.88	$ 17,388.17	$ 6,977.58		124.400	263.08	$ 4,737.43	312.000	87.01	YES	100	-	$ 18.01	$ -
44.88	08/04/2025	22	$ 16,791.15	356.500	$ 47.10	$ 15,997.94	$ 793.21		324.229	32.27	$ 71.80	304.000	87.01	YES	100	-	$ 2.23	$ -
44.88	08/04/2025	23	$ 7,207.01	158.570	$ 45.45	$ 7,115.83	$ 91.18		394.704	-	$ -	232.000	87.01	YES	100	-	$ 0.58	$ -
43.31	08/05/2025	10	$ 8,893.04	201.900	$ 44.05	$ 8,744.89	$ 148.15		391.583	-	$ -	264.000	87.01	YES	100	-	$ 0.73	$ -
43.31	08/05/2025	12	$ 15,089.00	323.340	$ 46.67	$ 14,004.83	$ 1,084.17		389.917	-	$ -	314.000	87.01	YES	100	-	$ 3.35	$ -
43.31	08/05/2025	13	$ 27,433.89	492.380	$ 55.72	$ 21,326.45	$ 6,107.44		373.942	118.44	$ 1,469.09	314.000	87.01	YES	100	-	$ 12.40	$ -
43.31	08/05/2025	14	$ 18,693.46	391.500	$ 47.75	$ 16,957.04	$ 1,736.42		198.833	192.67	$ 854.54	314.000	87.01	YES	100	-	$ 4.44	$ -
43.31	08/05/2025	15	$ 20,390.15	331.400	$ 61.53	$ 14,353.93	$ 6,036.22		151.500	179.90	$ 3,276.75	314.000	87.01	YES	100	-	$ 18.21	$ -
43.31	08/05/2025	16	$ 1,583.61	26.800	$ 59.09	$ 1,160.79	$ 422.82	*Brown 3 was on Reserve Shutdown and Culley 3 was on outage*	191.888	-	$ -	314.000	87.01	YES	100	-	$ 15.78	$ -
43.31	08/05/2025	18	$ 1,377.51	22.200	$ 62.05	$ 961.55	$ 415.96		130.000	-	$ -	314.000	87.01	YES	100	-	$ 18.74	$ -
43.31	08/05/2025	19	$ 21,362.88	423.470	$ 50.45	$ 18,341.76	$ 3,021.12		113.167	310.30	$ 2,213.77	314.000	87.01	YES	100	-	$ 7.13	$ -
43.31	08/05/2025	20	$ 9,163.87	135.500	$ 67.63	$ 5,868.91	$ 3,294.96		121.404	14.10	$ 342.77	314.000	87.01	YES	100	-	$ 24.32	$ -
43.31	08/05/2025	21	$ 26,155.37	512.810	$ 51.00	$ 22,211.34	$ 3,944.03		153.838	358.97	$ 2,760.86	314.000	87.01	YES	100	44.97	$ 7.69	$ 51.88
43.31	08/05/2025	23	$ 16,528.49	302.280	$ 54.68	$ 13,092.65	$ 3,435.84		383.150	-	$ -	314.000	87.01	YES	100	-	$ 11.37	$ -
44.69	08/06/2025	13	$ 13,350.74	266.800	$ 50.04	$ 11,922.76	$ 1,427.98		152.833	113.97	$ 609.98	292.000	87.01	YES	100	-	$ 5.35	$ -
44.69	08/06/2025	14	$ 13,135.18	246.300	$ 53.33	$ 11,006.65	$ 2,128.53		150.000	96.30	$ 832.22	292.000	87.01	YES	100	-	$ 8.64	$ -
44.69	08/06/2025	15	$ 14,964.30	255.800	$ 58.50	$ 11,431.19	$ 3,533.11		133.000	122.80	$ 1,696.11	292.000	87.01	YES	100	-	$ 13.81	$ -
44.69	08/06/2025	16	$ 13,695.74	207.700	$ 65.94	$ 9,281.70	$ 4,414.04		87.000	120.70	$ 2,565.12	292.000	87.01	YES	100	-	$ 21.25	$ -
44.69	08/06/2025	17	$ 16,962.27	237.900	$ 71.30	$ 10,631.28	$ 6,330.99		85.000	152.90	$ 4,068.97	292.000	87.01	YES	100	-	$ 26.61	$ -
44.69	08/06/2025	18	$ 21,471.91	272.500	$ 78.80	$ 12,177.48	$ 9,294.43	*Culley 3 and Brown 3 were on outage*	97.721	174.78	$ 5,961.36	313.000	87.01	YES	100	-	$ 34.11	$ -
44.69	08/06/2025	19	$ 32,773.42	335.000	$ 97.83	$ 14,970.48	$ 17,802.94		75.000	260.00	$ 13,817.21	313.000	87.01	YES	100	-	$ 53.14	$ -
44.69	08/06/2025	20	$ 34,940.94	422.000	$ 82.80	$ 18,858.34	$ 16,082.60		76.000	346.00	$ 13,186.21	313.000	87.01	YES	100	33.00	$ 38.11	$ 188.65
44.69	08/06/2025	21	$ 28,382.71	410.000	$ 69.23	$ 18,322.08	$ 10,060.63		2.291	407.71	$ 10,004.41	388.000	87.01	YES	100	19.71	$ 24.54	$ 72.54
44.69	08/06/2025	22	$ 27,483.12	504.000	$ 54.53	$ 22,522.75	$ 4,960.37		151.075	352.93	$ 3,473.49	389.000	87.01	YES	100	-	$ 9.84	$ -
45.25	08/07/2025	12	$ 19,494.55	429.490	$ 45.39	$ 19,434.42	$ 60.13		213.125	216.37	$ 30.29	388.000	87.01	YES	100	-	$ 0.14	$ -
45.25	08/07/2025	13	$ 13,295.65	261.880	$ 50.77	$ 11,850.07	$ 1,445.58		20.000	241.88	$ 1,335.18	389.000	87.01	YES	100	-	$ 5.52	$ -
45.25	08/07/2025	14	$ 18,350.77	309.770	$ 59.24	$ 14,017.09	$ 4,333.68		22.783	286.99	$ 4,014.94	389.000	87.01	YES	100	-	$ 13.99	$ -
45.25	08/07/2025	15	$ 18,371.65	282.120	$ 65.12	$ 12,765.93	$ 5,605.72		34.496	247.62	$ 4,920.29	335.000	87.01	YES	100	-	$ 19.87	$ -
45.25	08/07/2025	16	$ 20,438.98	296.260	$ 68.99	$ 13,405.77	$ 7,033.22		6.854	289.41	$ 6,870.50	326.000	87.01	YES	100	-	$ 23.74	$ -
45.25	08/07/2025	17	$ 16,805.90	229.840	$ 73.12	$ 10,400.26	$ 6,405.64	*Culley 3 and Brown 3 were on outage*	9.417	220.42	$ 6,143.19	314.000	87.01	YES	100	-	$ 27.87	$ -
45.25	08/07/2025	18	$ 20,999.95	268.370	$ 78.25	$ 12,143.74	$ 8,856.21		33.225	235.15	$ 7,759.78	314.000	87.01	YES	100	-	$ 33.00	$ -
45.25	08/07/2025	19	$ 32,751.95	357.320	$ 91.66	$ 16,168.73	$ 16,583.22		46.117	311.20	$ 14,442.93	314.000	87.01	YES	100	-	$ 46.41	$ -
45.25	08/07/2025	20	$ 34,820.19	441.470	$ 78.87	$ 19,976.52	$ 14,843.67		63.212	378.26	$ 12,718.28	314.000	87.01	YES	100	64.26	$ 33.62	$ 324.08
45.25	08/07/2025	21	$ 28,774.26	471.400	$ 61.04	$ 21,330.85	$ 7,443.41		137.854	333.55	$ 5,266.69	314.000	87.01	YES	100	19.55	$ 15.79	$ 46.29
45.25	08/07/2025	22	$ 25,371.85	510.500	$ 49.70	$ 23,100.13	$ 2,271.73		254.903	255.60	$ 1,137.41	314.000	87.01	YES	100	-	$ 4.45	$ -
45.56	08/08/2025	11	$ 21,536.54	453.210	$ 47.52	$ 20,649.61	$ 886.93		383.000	70.21	$ 137.40	314.000	87.01	YES	100	-	$ 1.96	$ -
45.56	08/08/2025	12	$ 16,799.83	325.200	$ 51.66	$ 14,817.09	$ 1,982.74		234.700	90.50	$ 551.78	314.000	87.01	YES	100	-	$ 6.10	$ -
45.56	08/08/2025	13	$ 19,423.64	342.750	$ 56.67	$ 15,616.72	$ 3,806.92		165.717	177.03	$ 1,966.30	314.000	87.01	YES	100	-	$ 11.11	$ -
45.56	08/08/2025	14	$ 20,981.16	348.640	$ 60.18	$ 15,885.08	$ 5,096.08		154.083	194.56	$ 2,843.84	314.000	87.01	YES	100	-	$ 14.62	$ -
45.56	08/08/2025	15	$ 20,985.60	318.060	$ 65.98	$ 14,491.77	$ 6,493.83		100.721	217.34	$ 4,437.41	314.000	87.01	YES	100	-	$ 20.42	$ -
45.56	08/08/2025	16	$ 25,939.88	381.350	$ 68.02	$ 17,375.45	$ 8,564.43	*Culley 3 was on outage Brown 3 and Brown 4 short run times*	110.779	270.57	$ 6,076.53	314.000	87.01	YES	100	-	$ 22.46	$ -
45.56	08/08/2025	17	$ 25,890.47	360.090	$ 71.90	$ 16,406.78	$ 9,483.69		87.583	272.51	$ 7,177.02	314.000	87.01	YES	100	-	$ 26.34	$ -
45.56	08/08/2025	18	$ 27,799.56	353.100	$ 78.73	$ 16,088.30	$ 11,711.26		74.075	279.03	$ 9,254.42	314.000	87.01	YES	100	-	$ 33.17	$ -
45.56	08/08/2025	19	$ 32,889.82	323.910	$ 101.54	$ 14,758.31	$ 18,131.51		8.609	315.30	$ 17,649.60	314.000	87.01	YES	100	1.30	$ 55.98	$ 10.92
45.56	08/08/2025	20	$ 30,573.44	385.250	$ 79.36	$ 17,553.15	$ 13,020.29		10.488	374.76	$ 12,665.83	314.000	87.01	YES	100	60.76	$ 33.80	$ 308.04
45.56	08/08/2025	21	$ 26,944.39	416.580	$ 64.68	$ 18,980.63	$ 7,963.76		68.480	348.10	$ 6,654.62	314.000	87.01	YES	100	34.10	$ 19.12	$ 97.78

CenterPoint Energy Indiana South
Market Settlements Group
Purchased Power Over Benchmark Explanations Cause No. 38708 FAC 149

S55's through 08/31

Aug Benchmark Costs	Trade Date	HE	Cost of Purchased Power	Purchases Volume	Price	Purchases Volume @ Benchmark $	Amount Over Benchmark $	Reason for Purchasing Power	Available Capacity of Units Not Selected	MISO Economic Dispatch / Purchased MWs above Capacity	Purchase Power Costs at Risk	Test for Outages and Derates: MWs Out of Service	Test for Outages and Derates: 11% of Summer Rated Capacity	Test for Outages and Derates: Are Unit MWs Out of Service > 11% Summer Capacity?	Recoverable @ 0%, 85%, or 100%	MWs Subject to 85% 15%	Over Benchmark Price	Total Unrecoverable Dollars
45.56	08/08/2025	22	$ 22,324.34	448.370	$ 49.79	$ 20,429.08	$ 1,895.26		118.204	330.17	$ 1,395.61	314.000	87.01	YES	100	16.17	$ 4.23	$ 10.25
45.50	08/09/2025	12	$ 11,566.18	228.400	$ 50.64	$ 10,392.20	$ 1,173.98		277.625	-	$ -	314.000	87.01	YES	100	-	$ 5.14	$ -
45.50	08/09/2025	13	$ 12,078.91	237.400	$ 50.88	$ 10,801.70	$ 1,277.21		240.000	-	$ -	392.000	87.01	YES	100	-	$ 5.38	$ -
45.50	08/09/2025	14	$ 15,503.76	282.400	$ 54.90	$ 12,849.20	$ 2,654.56		183.000	99.40	$ 934.36	392.000	87.01	YES	100	-	$ 9.40	$ -
45.50	08/09/2025	15	$ 17,670.35	306.380	$ 57.67	$ 13,940.29	$ 3,730.06		167.144	139.24	$ 1,695.15	392.000	87.01	YES	100	-	$ 12.17	$ -
45.50	08/09/2025	16	$ 22,500.96	340.170	$ 66.15	$ 15,477.74	$ 7,023.23		100.063	240.11	$ 4,957.30	392.000	87.01	YES	100	-	$ 20.65	$ -
45.50	08/09/2025	17	$ 22,831.42	316.420	$ 72.16	$ 14,397.11	$ 8,434.31	*Culley 2 and Culley 3 were on outage*	36.650	279.77	$ 7,457.39	392.000	87.01	YES	100	-	$ 26.66	$ -
45.50	08/09/2025	18	$ 24,217.65	359.970	$ 67.28	$ 16,378.64	$ 7,839.02	*all other units online*	51.675	308.30	$ 6,713.70	392.000	87.01	YES	100	-	$ 21.78	$ -
45.50	08/09/2025	19	$ 33,785.28	451.180	$ 74.88	$ 20,528.69	$ 13,256.59		71.875	379.31	$ 11,144.76	392.000	87.01	YES	100	-	$ 29.38	$ -
45.50	08/09/2025	20	$ 36,367.42	518.110	$ 70.19	$ 23,574.01	$ 12,793.42		74.767	443.34	$ 10,947.23	392.000	87.01	YES	100	51.34	$ 24.69	$ 190.17
45.50	08/09/2025	21	$ 36,669.97	615.680	$ 59.56	$ 28,013.44	$ 8,656.53		172.358	443.32	$ 6,233.16	392.000	87.01	YES	100	51.32	$ 14.06	$ 108.24
45.50	08/09/2025	22	$ 23,916.86	490.200	$ 48.79	$ 22,304.10	$ 1,612.76		259.987	230.21	$ 757.40	392.000	87.01	YES	100	-	$ 3.29	$ -
45.50	08/09/2025	24	$ 2,264.37	46.240	$ 48.97	$ 2,103.92	$ 160.45		369.000	-	$ -	392.000	87.01	YES	100	-	$ 3.47	$ -
45.50	08/10/2025	12	$ 14,391.30	249.200	$ 57.75	$ 11,338.60	$ 3,052.70		270.000	-	$ -	392.000	87.01	YES	100	-	$ 12.25	$ -
45.50	08/10/2025	13	$ 15,111.10	261.800	$ 57.72	$ 11,911.90	$ 3,199.20		239.000	22.80	$ 278.62	392.000	87.01	YES	100	-	$ 12.22	$ -
45.50	08/10/2025	14	$ 15,438.90	234.100	$ 65.95	$ 10,651.55	$ 4,787.35		177.029	57.07	$ 1,167.10	392.000	87.01	YES	100	-	$ 20.45	$ -
45.50	08/10/2025	15	$ 18,747.58	255.800	$ 73.29	$ 11,638.90	$ 7,108.68		130.783	125.02	$ 3,474.22	392.000	87.01	YES	100	-	$ 27.79	$ -
45.50	08/10/2025	16	$ 21,792.28	292.200	$ 74.58	$ 13,295.10	$ 8,497.18		119.358	172.84	$ 5,026.25	392.000	87.01	YES	100	-	$ 29.08	$ -
45.50	08/10/2025	17	$ 21,636.92	245.400	$ 88.17	$ 11,165.70	$ 10,471.22	*Culley 2 and Culley 3 were on outage*	111.278	134.12	$ 5,722.99	392.000	87.01	YES	100	-	$ 42.67	$ -
45.50	08/10/2025	18	$ 32,214.11	290.460	$ 110.91	$ 13,215.93	$ 18,998.18	*all other units online*	37.675	252.79	$ 16,533.96	392.000	87.01	YES	100	-	$ 65.41	$ -
45.50	08/10/2025	19	$ 57,534.58	372.210	$ 154.58	$ 16,935.56	$ 40,599.03		33.000	339.21	$ 36,999.53	392.000	87.01	YES	100	-	$ 109.08	$ -
45.50	08/10/2025	20	$ 42,337.59	439.130	$ 96.41	$ 19,980.42	$ 22,357.18		50.192	388.94	$ 19,801.78	392.000	87.01	YES	100	-	$ 50.91	$ -
45.50	08/10/2025	21	$ 36,523.25	484.880	$ 75.32	$ 22,062.04	$ 14,461.21		102.358	382.52	$ 11,408.45	392.000	87.01	YES	100	-	$ 29.82	$ -
45.50	08/10/2025	22	$ 29,664.32	425.600	$ 69.70	$ 19,364.80	$ 10,299.52		188.821	236.78	$ 5,730.05	392.000	87.01	YES	100	-	$ 24.20	$ -
45.50	08/10/2025	23	$ 23,804.46	447.200	$ 53.23	$ 20,347.60	$ 3,456.86		260.792	186.41	$ 1,440.94	392.000	87.01	YES	100	-	$ 7.73	$ -
45.50	08/10/2025	24	$ 26,210.89	566.110	$ 46.30	$ 25,758.01	$ 452.88		361.346	204.76	$ 163.81	392.000	87.01	YES	100	-	$ 0.80	$ -
45.50	08/11/2025	10	$ 16,543.93	324.200	$ 51.03	$ 14,751.10	$ 1,792.83		260.000	64.20	$ 355.03	392.000	87.01	YES	100	-	$ 5.53	$ -
45.50	08/11/2025	11	$ 21,827.94	356.200	$ 61.28	$ 16,207.10	$ 5,620.84		214.000	142.20	$ 2,243.92	392.000	87.01	YES	100	-	$ 15.78	$ -
45.50	08/11/2025	12	$ 24,794.00	322.000	$ 77.00	$ 14,651.00	$ 10,143.00		156.117	165.88	$ 5,225.31	392.000	87.01	YES	100	-	$ 31.50	$ -
45.50	08/11/2025	13	$ 24,520.06	334.250	$ 73.36	$ 15,208.38	$ 9,311.69		95.555	238.70	$ 6,649.67	392.000	87.01	YES	100	-	$ 27.86	$ -
45.50	08/11/2025	14	$ 31,265.72	319.100	$ 97.98	$ 14,519.05	$ 16,746.67		51.367	267.73	$ 14,050.88	392.000	87.01	YES	100	-	$ 52.48	$ -
45.50	08/11/2025	15	$ 36,910.52	346.280	$ 106.59	$ 15,755.74	$ 21,154.78		33.688	312.59	$ 19,096.73	392.000	87.01	YES	100	-	$ 61.09	$ -
45.50	08/11/2025	16	$ 42,190.87	351.580	$ 120.00	$ 15,996.89	$ 26,193.98		27.746	323.83	$ 24,126.80	392.000	87.01	YES	100	-	$ 74.50	$ -
45.50	08/11/2025	17	$ 42,691.16	357.400	$ 119.45	$ 16,261.70	$ 26,429.46	*Culley 2 and Culley 3 were on outage*	34.000	323.40	$ 23,915.19	392.000	87.01	YES	100	-	$ 73.95	$ -
45.50	08/11/2025	18	$ 44,205.41	357.100	$ 123.79	$ 16,248.05	$ 27,957.36	*all other units online*	15.000	342.10	$ 26,783.01	392.000	87.01	YES	100	-	$ 78.29	$ -
45.50	08/11/2025	19	$ 76,991.16	461.610	$ 166.79	$ 21,003.26	$ 55,987.91		29.000	432.61	$ 52,470.54	392.000	87.01	YES	100	40.61	$ 121.29	$ 738.83
45.50	08/11/2025	20	$ 60,001.85	543.330	$ 110.43	$ 24,721.52	$ 35,280.34		36.000	507.33	$ 32,942.73	392.000	87.01	YES	100	115.33	$ 64.93	$ 1,123.32
45.50	08/11/2025	21	$ 46,645.04	522.270	$ 89.31	$ 23,763.29	$ 22,881.76		31.550	490.72	$ 21,499.48	392.000	87.01	YES	100	98.72	$ 43.81	$ 648.77
45.50	08/11/2025	22	$ 35,681.22	539.970	$ 66.08	$ 24,568.64	$ 11,112.59		99.079	440.89	$ 9,073.54	392.000	87.01	YES	100	48.89	$ 20.58	$ 150.93
45.50	08/11/2025	23	$ 28,923.93	568.410	$ 50.89	$ 25,862.66	$ 3,061.28		198.671	369.74	$ 1,991.30	392.000	87.01	YES	100	-	$ 5.39	$ -
45.50	08/11/2025	24	$ 25,106.95	525.800	$ 47.75	$ 23,923.90	$ 1,183.05		242.946	282.85	$ 636.42	392.000	87.01	YES	100	-	$ 2.25	$ -
45.13	08/12/2025	1	$ 2,199.56	35.630	$ 61.73	$ 1,607.80	$ 591.76		439.967	-	$ -	314.000	87.01	YES	100	-	$ 16.61	$ -
45.13	08/12/2025	6	$ 2,890.23	41.470	$ 69.69	$ 1,871.33	$ 1,018.90		376.504	-	$ -	314.000	87.01	YES	100	-	$ 24.57	$ -
45.13	08/12/2025	7	$ 25,641.17	542.900	$ 47.23	$ 24,498.36	$ 1,142.81		380.267	162.63	$ 342.34	314.000	87.01	YES	100	-	$ 2.11	$ -
45.13	08/12/2025	10	$ 11,337.71	223.800	$ 50.66	$ 10,098.98	$ 1,238.74		200.417	23.38	$ 129.43	314.000	87.01	YES	100	-	$ 5.54	$ -
45.13	08/12/2025	11	$ 13,336.13	246.600	$ 54.08	$ 11,127.83	$ 2,208.31		157.617	88.98	$ 796.84	314.000	87.01	YES	100	-	$ 8.96	$ -
45.13	08/12/2025	12	$ 20,365.46	304.040	$ 66.98	$ 13,719.81	$ 6,645.66		107.725	196.32	$ 4,291.02	314.000	87.01	YES	100	-	$ 21.86	$ -
45.13	08/12/2025	13	$ 22,770.35	282.590	$ 80.58	$ 12,751.87	$ 10,018.48		78.016	204.57	$ 7,252.63	314.000	87.01	YES	100	-	$ 35.45	$ -
45.13	08/12/2025	14	$ 28,713.85	440.620	$ 65.17	$ 19,882.98	$ 8,830.87		176.166	264.45	$ 5,300.17	314.000	87.01	YES	100	-	$ 20.04	$ -
45.13	08/12/2025	15	$ 20,655.97	259.040	$ 79.74	$ 11,689.18	$ 8,966.79	*Culley 2 and Culley 3 were on outage*	26.167	232.87	$ 8,061.01	314.000	87.01	YES	100	-	$ 34.62	$ -
45.13	08/12/2025	16	$ 23,993.91	320.540	$ 74.85	$ 14,464.37	$ 9,529.54	*all other units online*	44.950	275.59	$ 8,193.19	314.000	87.01	YES	100	-	$ 29.73	$ -
45.13	08/12/2025	17	$ 25,208.72	317.900	$ 79.30	$ 14,345.24	$ 10,863.48		53.000	264.90	$ 9,052.33	314.000	87.01	YES	100	-	$ 34.17	$ -
45.13	08/12/2025	18	$ 28,124.00	306.870	$ 91.65	$ 13,847.51	$ 14,276.49		55.604	251.27	$ 11,689.63	314.000	87.01	YES	100	-	$ 46.52	$ -
45.13	08/12/2025	19	$ 49,036.25	455.970	$ 107.54	$ 20,575.65	$ 28,460.60		81.838	374.13	$ 23,352.46	314.000	87.01	YES	100	60.13	$ 62.42	$ 563.00
45.13	08/12/2025	20	$ 39,240.09	428.740	$ 91.52	$ 19,346.89	$ 19,893.20		47.800	380.94	$ 17,675.32	314.000	87.01	YES	100	66.94	$ 46.40	$ 465.89
45.13	08/12/2025	21	$ 30,681.13	365.900	$ 83.85	$ 16,511.24	$ 14,169.89		73.517	292.38	$ 11,322.86	314.000	87.01	YES	100	-	$ 38.73	$ -
45.13	08/12/2025	22	$ 28,651.91	428.600	$ 66.85	$ 19,340.58	$ 9,311.34		157.913	270.69	$ 5,880.68	314.000	87.01	YES	100	-	$ 21.73	$ -
45.13	08/12/2025	23	$ 20,233.61	351.400	$ 57.58	$ 15,856.93	$ 4,376.69		217.646	133.75	$ 1,665.91	314.000	87.01	YES	100	-	$ 12.45	$ -
45.13	08/12/2025	24	$ 18,897.23	372.800	$ 50.69	$ 16,822.60	$ 2,074.63		280.909	91.89	$ 511.37	314.000	87.01	YES	100	-	$ 5.56	$ -
44.13	08/13/2025	11	$ 19,033.00	397.100	$ 47.93	$ 17,522.04	$ 1,510.96		372.571	24.53	$ 93.33	315.000	87.01	YES	100	-	$ 3.80	$ -
44.13	08/13/2025	12	$ 21,818.63	415.200	$ 52.55	$ 18,320.70	$ 3,497.93		334.000	81.20	$ 684.08	315.000	87.01	YES	100	-	$ 8.42	$ -
44.13	08/13/2025	13	$ 20,867.39	349.700	$ 59.67	$ 15,430.51	$ 5,436.88		198.000	151.70	$ 2,358.52	315.000	87.01	YES	100	-	$ 15.55	$ -
44.13	08/13/2025	14	$ 16,354.10	239.200	$ 68.37	$ 10,554.70	$ 5,799.40		88.100	151.10	$ 3,663.42	315.000	87.01	YES	100	-	$ 24.24	$ -
44.13	08/13/2025	15	$ 19,280.97	288.600	$ 66.81	$ 12,734.48	$ 6,546.50		88.333	200.27	$ 4,542.78	315.000	87.01	YES	100	-	$ 22.68	$ -
44.13	08/13/2025	16	$ 19,341.56	254.260	$ 76.07	$ 11,219.22	$ 8,122.34	*Culley 3 was on outage all other units*	63.725	190.54	$ 6,086.64	315.000	87.01	YES	100	-	$ 31.95	$ -
44.13	08/13/2025	17	$ 25,754.55	308.750	$ 83.42	$ 13,623.59	$ 12,130.96	*online*	27.000	281.75	$ 11,070.11	315.000	87.01	YES	100	-	$ 39.29	$ -
44.13	08/13/2025	18	$ 31,212.02	416.720	$ 74.90	$ 18,387.77	$ 12,824.25		61.900	354.82	$ 10,919.32	315.000	87.01	YES	100	39.82	$ 30.77	$ 183.81
44.13	08/13/2025	19	$ 45,134.11	609.860	$ 74.01	$ 26,910.07	$ 18,224.04		267.000	342.86	$ 10,245.46	315.000	87.01	YES	100	27.86	$ 29.88	$ 124.88
44.13	08/13/2025	20	$ 32,759.29	440.860	$ 74.31	$ 19,452.95	$ 13,306.34		95.208	345.65	$ 10,432.71	315.000	87.01	YES	100	30.65	$ 30.18	$ 138.77

CenterPoint Energy Indiana South
Market Settlements Group
Purchased Power Over Benchmark Explanations Cause No. 38708 FAC 149

S55's through 08/31

Aug Benchmark Costs	Trade Date	HE	Cost of Purchased Power	Purchases Volume	Price	Purchases Volume @ Benchmark $	Amount Over Benchmark $	Reason for Purchasing Power	Available Capacity of Units Not Selected	MISO Economic Dispatch / Purchased MWs above Capacity	Purchase Power Costs at Risk	Test for Outages and Derates: MWs Out of Service	11% of Summer Rated Capacity	Are Unit MWs Out of Service > 11% Summer Capacity?	Recoverable @ 0%, 85%, or 100%	MWs Subject to 85% 15%	Over Benchmark Price	Total Unrecoverable Dollars
44.13	08/13/2025	21	$ 27,524.74	445.810	$ 61.74	$ 19,671.37	$ 7,853.37		97.217	348.59	$ 6,140.80	315.000	87.01	YES	100	33.59	$ 17.62	$ 88.77
44.13	08/13/2025	22	$ 28,464.37	605.110	$ 47.04	$ 26,700.48	$ 1,763.89		310.467	294.64	$ 858.88	315.000	87.01	YES	100	-	$ 2.91	$ -
43.94	08/14/2025	11	$ 20,315.66	455.100	$ 44.64	$ 19,996.18	$ 319.48		392.642	62.46	$ 43.84	314.000	87.01	YES	100	-	$ 0.70	$ -
43.94	08/14/2025	12	$ 27,432.31	560.600	$ 48.93	$ 24,631.64	$ 2,800.67		366.883	193.72	$ 967.78	314.000	87.01	YES	100	-	$ 5.00	$ -
43.94	08/14/2025	13	$ 22,649.13	430.800	$ 52.57	$ 18,928.49	$ 3,720.64		186.383	244.42	$ 2,110.93	314.000	87.01	YES	100	-	$ 8.64	$ -
43.94	08/14/2025	14	$ 20,756.30	340.100	$ 61.03	$ 14,943.31	$ 5,812.99		231.042	109.06	$ 1,864.02	314.000	87.01	YES	100	-	$ 17.09	$ -
43.94	08/14/2025	15	$ 24,696.81	428.700	$ 57.61	$ 18,836.22	$ 5,860.59		132.107	296.59	$ 4,054.61	314.000	87.01	YES	100	-	$ 13.67	$ -
43.94	08/14/2025	16	$ 29,457.14	420.100	$ 70.12	$ 18,458.35	$ 10,998.79	*Culley 3 was on outage and Brown 3 was on Reserve Shutdown*	91.363	328.74	$ 8,606.78	314.000	87.01	YES	100	14.74	$ 26.18	$ 57.88
43.94	08/14/2025	17	$ 21,430.55	311.400	$ 68.82	$ 13,682.29	$ 7,748.26		173.279	138.12	$ 3,436.73	314.000	87.01	YES	100	-	$ 24.88	$ -
43.94	08/14/2025	18	$ 22,975.50	327.800	$ 70.09	$ 14,402.88	$ 8,572.62		160.791	167.01	$ 4,367.62	314.000	87.01	YES	100	-	$ 26.15	$ -
43.94	08/14/2025	19	$ 39,294.94	549.900	$ 71.46	$ 24,161.51	$ 15,133.43		124.283	425.62	$ 11,713.12	314.000	87.01	YES	100	111.62	$ 27.52	$ 460.76
43.94	08/14/2025	20	$ 36,596.91	540.600	$ 67.70	$ 23,752.88	$ 12,844.03		91.383	449.22	$ 10,672.87	314.000	87.01	YES	100	135.22	$ 23.76	$ 481.89
43.94	08/14/2025	21	$ 42,474.47	639.300	$ 66.44	$ 28,089.56	$ 14,384.91		194.029	445.27	$ 10,019.05	314.000	87.01	YES	100	131.27	$ 22.50	$ 443.06
43.94	08/14/2025	22	$ 31,267.22	695.600	$ 44.95	$ 30,563.27	$ 703.95		352.430	343.17	$ 347.29	314.000	87.01	YES	100	29.17	$ 1.01	$ 4.43
42.13	08/15/2025	11	$ 22,884.25	512.640	$ 44.64	$ 21,594.96	$ 1,289.29		357.567	155.07	$ 390.01	314.000	87.01	YES	100	-	$ 2.52	$ -
42.13	08/15/2025	12	$ 68,371.49	322.110	$ 212.26	$ 13,568.88	$ 54,802.61		369.000	-	$ -	49.000	87.01	NO	85	-	$ 170.14	$ -
42.13	08/15/2025	13	$ 4,626.51	80.340	$ 57.59	$ 3,384.32	$ 1,242.19		388.129	-	$ -	49.000	87.01	NO	85	-	$ 15.46	$ -
42.13	08/15/2025	14	$ 13,943.20	297.590	$ 46.85	$ 12,535.98	$ 1,407.22		272.683	24.91	$ 117.78	49.000	87.01	NO	85	24.91	$ 4.73	$ 17.67
42.13	08/15/2025	15	$ 13,905.57	213.990	$ 64.98	$ 9,014.33	$ 4,891.24		161.392	52.60	$ 1,202.25	49.000	87.01	NO	85	52.60	$ 22.86	$ 180.34
42.13	08/15/2025	16	$ 12,969.91	192.400	$ 67.41	$ 8,104.85	$ 4,865.06		133.796	58.60	$ 1,481.87	49.000	87.01	NO	85	58.60	$ 25.29	$ 222.28
42.13	08/15/2025	17	$ 18,686.97	172.670	$ 108.22	$ 7,273.72	$ 11,413.25	*All units online load greater than generation*	92.987	79.68	$ 5,266.94	49.000	87.01	NO	85	79.68	$ 66.10	$ 790.04
42.13	08/15/2025	18	$ 18,669.00	176.900	$ 105.53	$ 7,451.91	$ 11,217.09		89.108	87.79	$ 5,566.82	44.000	87.01	NO	85	87.79	$ 63.41	$ 835.02
42.13	08/15/2025	19	$ 25,423.77	230.500	$ 110.30	$ 9,709.81	$ 15,713.96		60.004	170.50	$ 11,623.28	44.000	87.01	NO	85	170.50	$ 68.17	$ 1,743.49
42.13	08/15/2025	20	$ 16,542.39	222.530	$ 74.34	$ 9,374.08	$ 7,168.31		89.158	133.37	$ 4,296.29	44.000	87.01	NO	85	133.37	$ 32.21	$ 644.44
42.13	08/15/2025	21	$ 12,403.81	177.400	$ 69.92	$ 7,472.98	$ 4,930.84		139.138	38.26	$ 1,063.49	44.000	87.01	NO	85	38.26	$ 27.80	$ 159.52
42.13	08/15/2025	22	$ 14,442.10	267.100	$ 54.07	$ 11,251.59	$ 3,190.51		259.900	7.20	$ 86.00	44.000	87.01	NO	85	7.20	$ 11.95	$ 12.90
42.13	08/15/2025	23	$ 17,639.56	417.900	$ 42.21	$ 17,604.04	$ 35.52		422.783	-	$ -	44.000	87.01	NO	85	-	$ 0.09	$ -
44.63	08/16/2025	14	$ 1,163.42	17.700	$ 65.73	$ 789.86	$ 373.56		95.792	-	$ -	27.000	87.01	NO	85	-	$ 21.10	$ -
44.63	08/16/2025	15	$ 3,262.60	68.110	$ 47.90	$ 3,039.41	$ 223.19		61.083	7.03	$ 23.03	27.000	87.01	NO	85	7.03	$ 3.28	$ 3.45
44.63	08/16/2025	16	$ 1,097.96	13.900	$ 78.99	$ 620.29	$ 477.67		53.000	-	$ -	37.000	87.01	NO	85	-	$ 34.36	$ -
44.63	08/16/2025	17	$ 5,591.69	96.410	$ 58.00	$ 4,302.30	$ 1,289.39		50.000	46.41	$ 620.69	37.000	87.01	NO	85	46.41	$ 13.37	$ 93.10
44.63	08/16/2025	18	$ 8,728.28	132.560	$ 65.84	$ 5,915.49	$ 2,812.79	*All units online load greater than generation*	39.000	93.56	$ 1,985.25	37.000	87.01	NO	85	93.56	$ 21.22	$ 297.79
44.63	08/16/2025	19	$ 10,439.16	88.400	$ 118.09	$ 3,944.85	$ 6,494.31		54.833	33.57	$ 2,466.00	37.000	87.01	NO	85	33.57	$ 73.47	$ 369.90
44.63	08/16/2025	20	$ 11,387.19	124.600	$ 91.39	$ 5,560.28	$ 5,826.92		62.000	62.60	$ 2,927.49	37.000	87.01	NO	85	62.60	$ 46.76	$ 439.12
44.63	08/16/2025	21	$ 12,499.00	187.620	$ 66.62	$ 8,372.54	$ 4,126.46		51.358	136.26	$ 2,996.91	37.000	87.01	NO	85	136.26	$ 21.99	$ 449.54
44.63	08/16/2025	22	$ 11,710.08	203.300	$ 57.60	$ 9,072.26	$ 2,637.82		156.200	47.10	$ 611.12	37.000	87.01	NO	85	47.10	$ 12.98	$ 91.67
44.63	08/17/2025	12	$ 7,749.53	165.200	$ 46.91	$ 7,372.05	$ 377.48		305.000	-	$ -	27.000	87.01	NO	85	-	$ 2.28	$ -
44.63	08/17/2025	13	$ 9,971.93	203.800	$ 48.93	$ 9,094.58	$ 877.36		253.545	-	$ -	27.000	87.01	NO	85	-	$ 4.30	$ -
44.63	08/17/2025	14	$ 11,406.85	224.500	$ 50.81	$ 10,018.31	$ 1,388.54		205.929	18.57	$ 114.86	27.000	87.01	NO	85	18.57	$ 6.19	$ 17.23
44.63	08/17/2025	15	$ 13,266.88	220.600	$ 60.14	$ 9,844.28	$ 3,422.61		171.333	49.27	$ 764.38	27.000	87.01	NO	85	49.27	$ 15.51	$ 114.66
44.63	08/17/2025	16	$ 12,098.28	198.170	$ 61.05	$ 8,843.34	$ 3,254.94		115.500	82.67	$ 1,357.86	27.000	87.01	NO	85	82.67	$ 16.43	$ 203.68
44.63	08/17/2025	17	$ 12,281.55	185.550	$ 66.19	$ 8,280.17	$ 4,001.38	*All units online load greater than generation*	76.992	108.56	$ 2,341.05	27.000	87.01	NO	85	108.56	$ 21.56	$ 351.16
44.63	08/17/2025	18	$ 15,121.53	196.690	$ 76.88	$ 8,777.29	$ 6,344.24		49.856	146.83	$ 4,736.13	27.000	87.01	NO	85	146.83	$ 32.26	$ 710.42
44.63	08/17/2025	19	$ 22,984.08	249.990	$ 91.94	$ 11,155.80	$ 11,828.28		44.400	205.59	$ 9,727.49	27.000	87.01	NO	85	205.59	$ 47.31	$ 1,459.12
44.63	08/17/2025	20	$ 20,020.77	321.000	$ 62.37	$ 14,324.63	$ 5,696.15		92.888	228.11	$ 4,047.85	27.000	87.01	NO	85	228.11	$ 17.75	$ 607.18
44.63	08/17/2025	21	$ 21,240.57	364.020	$ 58.35	$ 16,244.39	$ 4,996.18		160.546	203.47	$ 2,792.68	27.000	87.01	NO	85	203.47	$ 13.73	$ 418.90
44.63	08/17/2025	22	$ 15,792.43	347.010	$ 45.51	$ 15,485.32	$ 307.11		194.083	152.93	$ 135.34	27.000	87.01	NO	85	152.93	$ 0.89	$ 20.30
44.63	08/18/2025	12	$ 7,242.99	145.500	$ 49.78	$ 6,492.94	$ 750.05		309.333	-	$ -	48.000	87.01	NO	85	-	$ 5.16	$ -
44.63	08/18/2025	13	$ 6,912.71	119.000	$ 58.09	$ 5,310.38	$ 1,602.34		246.904	-	$ -	59.000	87.01	NO	85	-	$ 13.47	$ -
44.63	08/18/2025	14	$ 3,920.49	68.600	$ 57.15	$ 3,061.28	$ 859.22		212.738	-	$ -	59.000	87.01	NO	85	-	$ 12.53	$ -
44.63	08/18/2025	15	$ 3,272.25	49.700	$ 65.84	$ 2,217.86	$ 1,054.39		167.433	-	$ -	59.000	87.01	NO	85	-	$ 21.22	$ -
44.63	08/18/2025	16	$ 5,189.24	75.700	$ 68.55	$ 3,378.11	$ 1,811.13		177.575	-	$ -	59.000	87.01	NO	85	-	$ 23.93	$ -
44.63	08/18/2025	17	$ 7,948.71	96.500	$ 82.37	$ 4,306.31	$ 3,642.40	*All units online load greater than generation*	119.529	-	$ -	59.000	87.01	NO	85	-	$ 37.75	$ -
44.63	08/18/2025	18	$ 9,520.03	109.300	$ 87.10	$ 4,877.51	$ 4,642.52		103.659	5.64	$ 239.60	59.000	87.01	NO	85	5.64	$ 42.48	$ 35.94
44.63	08/18/2025	19	$ 25,881.31	195.570	$ 132.34	$ 8,727.31	$ 17,154.00		33.138	162.43	$ 14,247.37	59.000	87.01	NO	85	162.43	$ 87.71	$ 2,137.11
44.63	08/18/2025	20	$ 23,181.77	250.100	$ 92.69	$ 11,160.71	$ 12,021.06		72.975	177.13	$ 8,513.51	59.000	87.01	NO	85	177.13	$ 48.07	$ 1,277.03
44.63	08/18/2025	21	$ 16,208.55	218.150	$ 74.30	$ 9,734.94	$ 6,473.61		36.992	181.16	$ 5,375.87	59.000	87.01	NO	85	181.16	$ 29.68	$ 806.38
44.63	08/18/2025	22	$ 17,404.87	291.100	$ 59.79	$ 12,990.34	$ 4,414.53		204.213	86.89	$ 1,317.64	59.000	87.01	NO	85	86.89	$ 15.17	$ 197.65
44.50	08/19/2025	12	$ 6,024.12	119.550	$ 50.39	$ 5,319.98	$ 704.15		254.429	-	$ -	49.000	87.01	NO	85	-	$ 5.89	$ -
44.50	08/19/2025	13	$ 6,384.66	122.900	$ 51.95	$ 5,469.05	$ 915.61		313.546	-	$ -	49.000	87.01	NO	85	-	$ 7.45	$ -
44.50	08/19/2025	14	$ 7,298.25	131.500	$ 55.50	$ 5,851.75	$ 1,446.50		250.346	-	$ -	49.000	87.01	NO	85	-	$ 11.00	$ -
44.50	08/19/2025	15	$ 13,619.68	261.760	$ 52.03	$ 11,648.32	$ 1,971.36		188.667	73.09	$ 550.48	49.000	87.01	NO	85	73.09	$ 7.53	$ 82.57
44.50	08/19/2025	16	$ 12,096.78	200.920	$ 60.21	$ 8,940.94	$ 3,155.84	*All units online load greater than generation*	114.296	86.62	$ 1,360.60	49.000	87.01	NO	85	86.62	$ 15.71	$ 204.09
44.50	08/19/2025	17	$ 8,074.21	115.610	$ 69.84	$ 5,144.65	$ 2,929.57		21.444	94.17	$ 2,386.17	49.000	87.01	NO	85	94.17	$ 25.34	$ 357.93
44.50	08/19/2025	18	$ 10,177.44	160.790	$ 63.30	$ 7,155.16	$ 3,022.29		64.679	96.11	$ 1,806.55	49.000	87.01	NO	85	96.11	$ 18.80	$ 270.98
44.50	08/19/2025	19	$ 12,350.83	160.130	$ 77.13	$ 7,125.79	$ 5,225.05		111.891	48.24	$ 1,574.04	49.000	87.01	NO	85	48.24	$ 32.63	$ 236.11
44.50	08/19/2025	20	$ 3,845.08	60.070	$ 64.01	$ 2,673.12	$ 1,171.97		50.721	9.35	$ 182.40	49.000	87.01	NO	85	9.35	$ 19.51	$ 27.36
44.50	08/19/2025	21	$ 6,726.52	120.720	$ 55.72	$ 5,372.04	$ 1,354.48		141.708	-	$ -	49.000	87.01	NO	85	-	$ 11.22	$ -

CenterPoint Energy Indiana South
Market Settlements Group
Purchased Power Over Benchmark Explanations Cause No. 38708 FAC 149

S55's through 08/31

Aug Benchmark Costs	Trade Date	HE	Cost of Purchased Power	Purchases Volume	Price	Purchases Volume @ Benchmark $	Amount Over Benchmark $	Reason for Purchasing Power	Available Capacity of Units Not Selected	MISO Economic Dispatch / Purchased MWs above Capacity	Purchase Power Costs at Risk	Test for Outages and Derates: MWs Out of Service	11% of Summer Rated Capacity	Are Unit MWs Out of Service > 11% Summer Capacity?	Recoverable @ 0%, 85%, or 100%	MWs Subject to 85% 15%	Over Benchmark Price	Total Unrecoverable Dollars
43.25	08/20/2025	9	$ 10,396.08	46.250	$ 224.78	$ 2,000.31	$ 8,395.77	Brown 3 Brown 4 Brown 6 and Culley 2 were on Reserve Shutdown	448.800	-	$ -	49.000	87.01	NO	85	-	$ 181.53	$ -
43.25	08/20/2025	10	$ 1,037.36	22.280	$ 46.56	$ 963.61	$ 73.75		454.417	-	$ -	49.000	87.01	NO	85	-	$ 3.31	$ -
43.25	08/20/2025	19	$ 17,682.56	328.550	$ 53.82	$ 14,209.79	$ 3,472.77		446.792	-	$ -	49.000	87.01	NO	85	-	$ 10.57	$ -
43.25	08/20/2025	20	$ 19,083.91	418.140	$ 45.64	$ 18,084.56	$ 999.35		450.333	-	$ -	44.000	87.01	NO	85	-	$ 2.39	$ -
42.56	08/21/2025	14	$ 12,945.95	301.700	$ 42.91	$ 12,841.26	$ 104.69	Brown 3 Brown 4 and Culley 2 were on Reserve Shutdown	475.237	-	$ -	42.000	87.01	NO	85	-	$ 0.35	$ -
42.56	08/21/2025	15	$ 13,268.50	297.300	$ 44.63	$ 12,653.98	$ 614.52		440.009	-	$ -	42.000	87.01	NO	85	-	$ 2.07	$ -
42.56	08/21/2025	16	$ 4,332.87	93.000	$ 46.59	$ 3,958.36	$ 374.51		312.925	-	$ -	42.000	87.01	NO	85	-	$ 4.03	$ -
42.56	08/21/2025	17	$ 5,223.62	105.400	$ 49.56	$ 4,486.14	$ 737.48		315.888	-	$ -	42.000	87.01	NO	85	-	$ 7.00	$ -
42.56	08/21/2025	18	$ 7,754.59	145.900	$ 53.15	$ 6,209.94	$ 1,544.65		273.000	-	$ -	42.000	87.01	NO	85	-	$ 10.59	$ -
42.56	08/21/2025	19	$ 14,853.63	214.400	$ 69.28	$ 9,125.51	$ 5,728.12		300.954	-	$ -	42.000	87.01	NO	85	-	$ 26.72	$ -
42.56	08/21/2025	20	$ 13,946.48	231.400	$ 60.27	$ 9,849.08	$ 4,097.40		291.346	-	$ -	42.000	87.01	NO	85	-	$ 17.71	$ -
42.56	08/21/2025	21	$ 12,062.00	222.300	$ 54.26	$ 9,461.75	$ 2,600.25		311.179	-	$ -	42.000	87.01	NO	85	-	$ 11.70	$ -
42.56	08/21/2025	22	$ 17,921.50	400.570	$ 44.74	$ 17,049.46	$ 872.04		455.746	-	$ -	42.000	87.01	NO	85	-	$ 2.18	$ -
43.50	08/22/2025	15	$ 13,173.33	295.300	$ 44.61	$ 12,845.55	$ 327.78	Brown 3 Brown 4 and Culley 2 were on Reserve Shutdown	434.158	-	$ -	44.000	87.01	NO	85	-	$ 1.11	$ -
43.50	08/22/2025	16	$ 4,847.68	100.200	$ 48.38	$ 4,358.70	$ 488.98		287.000	-	$ -	44.000	87.01	NO	85	-	$ 4.88	$ -
43.50	08/22/2025	17	$ 6,135.48	119.600	$ 51.30	$ 5,202.60	$ 932.88		286.000	-	$ -	44.000	87.01	NO	85	-	$ 7.80	$ -
43.50	08/22/2025	18	$ 8,441.24	154.800	$ 54.53	$ 6,733.80	$ 1,707.44		294.229	-	$ -	44.000	87.01	NO	85	-	$ 11.03	$ -
43.50	08/22/2025	19	$ 11,289.28	177.700	$ 63.53	$ 7,729.95	$ 3,559.33		268.000	-	$ -	44.000	87.01	NO	85	-	$ 20.03	$ -
43.50	08/22/2025	20	$ 13,512.00	240.000	$ 56.30	$ 10,440.00	$ 3,072.00		273.196	-	$ -	44.000	87.01	NO	85	-	$ 12.80	$ -
43.50	08/22/2025	21	$ 11,326.76	231.300	$ 48.97	$ 10,061.55	$ 1,265.21		336.625	-	$ -	44.000	87.01	NO	85	-	$ 5.47	$ -
42.38	08/23/2025	19	$ 19,631.29	401.540	$ 48.89	$ 17,015.26	$ 2,616.03	Brown 3 Brown 4 Brown 6 and Culley 2 were on Reserve Shutdown	464.425	-	$ -	44.000	87.01	NO	85	-	$ 6.51	$ -
42.38	08/23/2025	20	$ 17,406.98	380.730	$ 45.72	$ 16,133.43	$ 1,273.55		457.000	-	$ -	44.000	87.01	NO	85	-	$ 3.35	$ -
42.38	08/23/2025	21	$ 16,492.25	369.450	$ 44.64	$ 15,655.44	$ 836.81		459.042	-	$ -	44.000	87.01	NO	85	-	$ 2.27	$ -
42.38	08/24/2025	20	$ 13,945.92	313.110	$ 44.54	$ 13,268.04	$ 677.88	Brown 3 Brown 4 Brown 6 and Culley 2 were on Reserve Shutdown	466.000	-	$ -	35.000	87.01	NO	85	-	$ 2.17	$ -
42.38	08/25/2025	19	$ 14,101.28	286.030	$ 49.30	$ 12,120.52	$ 1,980.76	Brown 3 Brown 4 Brown 6 and Culley 2 were on Reserve Shutdown	459.000	-	$ -	32.000	87.01	NO	85	-	$ 6.93	$ -
42.38	08/25/2025	20	$ 16,151.52	336.000	$ 48.07	$ 14,238.00	$ 1,913.52		459.000	-	$ -	32.000	87.01	NO	85	-	$ 5.70	$ -
42.75	08/27/2025	19	$ 10,156.49	224.950	$ 45.15	$ 9,616.61	$ 539.88	Brown 3 Brown 4 Brown 6 were on Reserve Shutdown Culley 2 was on outage	505.000	-	$ -	128.000	113.52	YES	100	-	$ 2.40	$ -
43.44	08/28/2025	19	$ 30,309.74	123.170	$ 246.08	$ 5,350.26	$ 24,959.48	Brown 3 Brown 4 and Brown 6 were on Reserve Shutdown	396.537	-	$ -	33.000	113.52	NO	85	-	$ 202.64	$ -
43.69	08/29/2025	15	$ 1,666.51	25.350	$ 65.74	$ 1,107.49	$ 559.02	Brown 3 Brown 4 and Brown 6 were on Reserve Shutdown	372.000	-	$ -	29.000	113.52	NO	85	-	$ 22.05	$ -
43.69	08/29/2025	19	$ 3,693.75	78.930	$ 46.80	$ 3,448.29	$ 245.46		386.003	-	$ -	50.000	113.52	NO	85	-	$ 3.11	$ -
43.69	08/29/2025	20	$ 4,100.21	88.500	$ 46.33	$ 3,866.39	$ 233.82		416.712	-	$ -	50.000	113.52	NO	85	-	$ 2.64	$ -
43.69	08/30/2025	19	$ 9,013.28	197.400	$ 45.66	$ 8,624.01	$ 389.27	All Brown units and Culley 2 were on Reserve Shutdown	757.104	-	$ -	49.000	113.52	NO	85	-	$ 1.97	$ -
43.69	08/31/2025	19	$ 11,484.76	256.700	$ 44.74	$ 11,214.71	$ 270.05	All Brown units and Culley 2 were on Reserve Shutdown	733.396	-	$ -	49.000	113.52	NO	85	-	$ 1.05	$ -
Total			**$ 4,561,220.41**	**67,507.510**		**$ 3,004,229.35**	**$ 1,556,991.21**		**47,268.271**	**32,799.783**	**$ 962,436.40**	**51,553.000**				**4,677.307**		**$ 22,969.90**

BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c) Emergency Order: Midcontinent Independent System Operator and Northern Indiana Public Service Company LLC	)))))	Order No. 202-26-19
Federal Power Act Section 202(c) Emergency Order: Midcontinent Independent System Operator and CenterPoint Energy Indiana South	))))	Order No. 202-26-20

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

Exhibit 57
2026 EPA IN Haze SIP Approval

EPA Regional Administrator, Anne Vogel, signed the following document on 1/6/2026, and EPA is submitting it for publication in the *Federal Register* (FR). EPA is providing this document solely for the convenience of interested parties. While we have taken steps to ensure the accuracy of this version of the document, the official version will be published in a forthcoming FR publication, which will appear on the Government Printing Office's govinfo website (https://www.govinfo.gov/app/collection/fr) and on Regulations.gov (https://www regulations.gov) in Docket No. EPA-R05-OAR-2021-0963

6560-50-P

ENVIRONMENTAL PROTECTION AGENCY

40 CFR Part 52

[EPA-R05-OAR-2021-0963; FRL-12589-02-R5]

Air Plan Approval; Indiana; Regional Haze Plan for the Second Implementation Period

AGENCY: Environmental Protection Agency (EPA).

ACTION: Final rule.

SUMMARY: The Environmental Protection Agency (EPA) is approving the Regional Haze State Implementation Plan (SIP) revision for Indiana submitted by the Indiana Department of Environmental Management (IDEM or Indiana) on December 29, 2021, as satisfying applicable requirements under the Clean Air Act (CAA) and EPA's Regional Haze Rule (RHR) for the program's second implementation period. Indiana's SIP submission addresses the requirement that States must periodically revise their long-term strategies for making reasonable progress towards the national goal of preventing any future, and remedying any existing, anthropogenic impairment of visibility, including regional haze, in mandatory Class I Federal areas. Indiana's SIP submission also addresses other applicable requirements for the second implementation period of the regional haze program. EPA is taking this action pursuant to sections 110 and 169A of the CAA.

DATES: This final rule is effective on **[insert date 30 days**

after date of publication in the *Federal Register*].

ADDRESSES: EPA has established a docket for this action under Docket ID No. EPA-R05-OAR-2021-0963. All documents in the docket are listed on the *https://www.regulations.gov* web site. Although listed in the index, some information is not publicly available, i.e., Confidential Business Information (CBI), Proprietary Business Information (PBI), or other information whose disclosure is restricted by statute. Certain other material, such as copyrighted material, is not placed on the Internet and will be publicly available only in hard copy form. Publicly available docket materials are available either through *https://www.regulations.gov* or at the Environmental Protection Agency, Region 5, Air and Radiation Division, 77 West Jackson Boulevard, Chicago, Illinois 60604. This facility is open from 8:30 a.m. to 4:30 p.m., Monday through Friday, excluding Federal holidays. We recommend that you telephone Charles Hatten, Environmental Engineer, at (312) 886-6031 before visiting the Region 5 office.

FOR FURTHER INFORMATION CONTACT: Charles Hatten, Air and Radiation Division (AR-18J), Environmental Protection Agency, Region 5, 77 West Jackson Boulevard, Chicago, Illinois 60604, (312) 886-6031, *hatten.charles@epa.gov*.

SUPPLEMENTARY INFORMATION: Throughout this document whenever "we," "us," or "our" is used, we mean EPA.

Table of Contents

I. Background

On December 29, 2021, IDEM submitted a revision to its SIP to address regional haze requirements for the second implementation period. IDEM made this SIP submission to satisfy the requirements of the CAA’s regional haze program pursuant to CAA sections 169A and 169B and 40 CFR 51.308.

On June 18, 2025 (90 FR 25944), EPA proposed to approve the Indiana regional haze SIP revision. In the notice of proposed rulemaking (NPRM), EPA proposed to find that Indiana’s Regional Haze SIP submission satisfied the regional haze requirements for the second implementation period contained in 40 CFR 51.308(f). As described further in EPA’s proposed approval, IDEM utilized technical analyses and its source selection methodology to target the sources with the highest potential to impair visibility at mandatory Class I areas.[1] IDEM's initial list of twenty candidate sources for a four-factor analysis represented the majority of Indiana's emissions that may influence visibility impacts on out-of-state Class I areas. IDEM further refined that list by excluding eleven electric generating units (EGUs) that either had existing effective controls or that were not expected to continue operating beyond 2028. IDEM then proceeded with site-specific four-factor analyses for the remining nine non-EGU facilities identified through this process. A detailed analysis of Indiana's plan and EPA's evaluation are contained in the NPRM, dated June 18, 2025 (90 FR 25944), as well as the Technical Support Document (TSD), dated April 22, 2025, and will not be restated here.

II. Public Comment Process

The public review and comment period on EPA's NPRM opened June 18, 2025, and was originally scheduled to close on July 18, 2025. On June 26, 2025, EPA received a comment letter from the National Parks Conservation Association, the Coalition to Protect America's National Parks, and the Sierra Club (Comment 1) requesting that EPA provide an additional 30 days for public

[1] There are no Class I areas in Indiana. However, the RHR requires SIPs to address Class I areas located outside the state that may be affected by emissions from within the state.

comment on the NPRM. On July 16, 2025 (90 FR 31923), EPA published a NPRM extending the public review and comment period to August 18, 2025.

During the review and comment period, EPA received relevant comments from the following individuals, businesses, agencies, and organizations: an individual identified as Kurtis K. (Comment 2); three anonymous commenters (Comments 3, 4, and 5); IDEM (Comment 6); Power Generators Air Coalition (Comment 7); Ameren Missouri, American Electric Power Company, Inc. on behalf of its operating companies, and Nebraska Public Power District (collectively referred as the "Utilities for Reasonable Progress") (Comment 8); Ohio Valley Electric Corporation (OVEC) and Indiana-Kentucky Electric Corporation (IKEC) (Comment 9); Abrams Environmental Law Clinic, Artists for Environmental Restoration, Inc., Citizens Climate Lobby – Evansville Chapter, Conservation Law Center, Environmental Advocacy Center at the Northwestern Pritzker School of Law, Faith in Place, Hessville Dune Dusters, Izaak Walton League – Indiana Division, Izaak Walton League – Porter County Chapter, Just Transition Northwest Indiana, National Parks Conservation Association, Owen-Putnam Friends of the Forest, Save the Dunes, Sierra Club – Hoosier Chapter, and Tri-State Creation Care (collectively referred to as "Community Organizations") (Comment 10); Mid-Atlantic/Northeast Visibility Union (MANEVU) regional planning organization (Comment 11); and National Parks Conservation Association, Sierra Club, Environmental Law & Policy Center, Coalition to Protect America's National Parks, Conservation Law Center, Save the Dunes, and the Indiana Division of the Izaak Walton League of America (collectively referred to as the "Conservation Groups") (Comments 12 through 23).

III. Summary of Public Comments and EPA's Responses

A. Comments Received

All comments received are included in the rulemaking docket for this action. In the December 19, 2025, Response to Comments document (RTC), which is included in the docket for this rulemaking, EPA provides summaries of and detailed responses to all significant comments that further explain the basis for our final action.

In addition to the request to extend the public comment period, EPA received comments on the NPRM addressing several topics including, but not limited to, additional emissions monitoring, increased public engagement, climate resilience, visibility trends, public health, economic benefits, enforceability of retirements, existing effective controls, four-factor analyses,[2] cost considerations, Best Available

[2] Under CAA 169A(g)(1), the four statutory factors are the costs of compliance, the time necessary for compliance, the energy and non-air quality environmental impacts of compliance, and the remaining useful life of any potentially affected sources. See also 40 CFR 51.308(f)(2)(i). An evaluation of potential control options for sources of visibility impairing

Retrofit Technology (BART), and impacts on local communities. Additionally, EPA received several comments regarding EPA's URP policy.[3]

EPA acknowledges the seven comments that were generally supportive of the proposed action and EPA's URP policy from Kurtis K. (Comment 2), two anonymous commenters (Comments 3 – 4), IDEM (Comment 6); PGen (Comment 7), Utilities for Reasonable Progress (Comment 8), as well as OVEC and IKEC (Comment 9). Comments received from the Community Organizations, MANEVU, and the Conservation Groups were generally opposed to EPA's proposed action: Comments 10 - 23. The comments, while summarized below, are available in full in the docket for this rulemaking and are addressed in EPA's December 19, 2025, RTC. The comments and EPA's responses summarized here are divided into two sections for those that are and are not specific to EPA's URP policy.

B. Comments and Responses that are not specific to EPA's URP Policy

Comment and Response 2: Comments from Kurtis K., while supportive of EPA's proposed action, suggested additional emissions monitoring at three facilities and increased public

pollutants based on applying the four statutory factors in CAA section 169A(g)(1) is referred to as a "four-factor" analysis.

[3] A change in Agency policy was introduced in the approval of West Virginia's regional haze plan. See the April 18, 2025, (90 FR 16478) proposed rule) and the July 7, 2025, (90 FR 29737) final rule.

engagement.

As addressed in the RTC, EPA notes that the type of emissions monitoring suggested is already provided for in the federally enforceable title V permits and considered in the visibility modeling efforts for the three facilities mentioned in the comment. As to providing for public engagement after SIP implementation, EPA notes that the RHR provides for public comment on SIP revisions and the progress of the SIP, generally every five years.

Comments and Responses 3, 4, 6, 7, 8, and 9: Comments received from two anonymous commenters, IDEM, PGen, Utilities for Reasonable Progress, as well as OVEC and IKEC supported EPA's proposed action. EPA acknowledges their support for EPA's proposed approval.

Comment and Response 10: The Community Organizations asserted that EPA's proposed approval will allow pollution to continue harming the air quality, public health, and economy of local and national parks and communities.

As addressed in the RTC, Indiana has taken appropriate steps to reduce pollution that affects air quality in the affected Class I areas, including meaningful sulfur dioxide (SO_2) and nitrogen oxides (NO_X) emission reductions since the beginning of the second implementation period in 2019. Most of these emissions reductions have already occurred during the second implementation period and will continue to improve visibility in all Class I areas affected by emissions from Indiana. EPA notes that the visibility program prescribed by CAA sections 169A and 169B and implemented in 40 CFR 51.308 is not a public health-based program, and impacts on park tourism and local economies are not considerations within the Regional Haze statute or rule.

Comment and Response 11: MANEVU raised several items for EPA's consideration relating to changing circumstances since the time that MANEVU sent its "Asks" to Indiana on November 5, 2021, during the State's regional haze planning efforts. MANEVU observed that the Lake Michigan Air Directors Consortium (LADCO) has documented that modeled levels of nitrate in the winter have apparently been underestimated, and that declining trends in visibility impairment appear to have "flattened" in recent years. As a result, MANEVU asserted that additional measures will be needed in the future "to reinvigorate robust visibility improvements."

As discussed in the RTC, EPA provides further explanation of LADCO's modeling and notes that MANEVU did not address a specific regulation or provision in question or recommend a different action on Indiana's 2021 SIP submission from what EPA proposed.

Comment and Response 12: The Conservation Groups assert that reducing haze pollution from Indiana facilities will improve visibility in Class I areas[4] and result in economic, public health, and environmental benefits.

As addressed in the RTC, concerns regarding public health, park visitation, and local economies are not considerations within the Regional Haze statute or rule.

Comment and Response 13: The Conservation Groups argue that EPA's proposal to approve the Indiana SIP Revision violates the CAA and RHR. In this regard, the Conservation Groups assert: (a) that EPA's reliance on permit limits and consent decrees, past emission reductions, and ongoing emission reductions to approve Indiana's 2021 SIP Revision is arbitrary and capricious; and (b) that Indiana failed to include federally enforceable measures in the 2021 SIP Revision for source retirements.

As detailed in the RTC, EPA disagrees with the Conservation Groups' assertions. Indiana did not rely on any planned EGU retirements, past emission reductions, reductions in utilization, or ongoing emission reductions that are not already federally enforceable as necessary to make reasonable progress in the second implementation period. As such, Indiana did not request any additional measures for the second implementation

[4] Areas statutorily designated as mandatory Class I Federal areas consist of national parks exceeding 6,000 acres, wilderness areas and national memorial parks exceeding 5,000 acres, and all international parks that were in existence on August 7, 1977. CAA 162(a). There are 156 mandatory Class I areas. The list of areas to which the requirements of the visibility protection program apply is in 40 CFR part 81, subpart D. Class I Federal areas are hereinafter referred to as "Class I areas".

period be incorporated into the regulatory portion of Indiana’s SIP at 40 CFR 52.770.

Comment and Response 14: The Conservation Groups assert that Indiana unreasonably refused to conduct four-factor analyses for sources that the State claimed are effectively controlled. The Conservation Groups argue that neither the CAA nor the RHR allows States to eliminate sources from the four-factor statutory analysis on the basis that they are effectively controlled. The Conservation Groups contend that Indiana’s demonstrations of existing effective controls are flawed and that reasonable controls or upgrades are available for these facilities at some of the State’s largest sources of regional haze-causing emissions, including Duke – Gibson, Alcoa – Warrick Power Plant, AEP – Rockport, IKEC – Clifty Creek, and Duke – Cayuga.

As further discussed in the RTC, EPA addresses this comment as well as comments regarding each of these five facilities below under Comments and Responses 14a to 14f, respectively.

Comment and Response 14a: **Existing Effective Control Demonstrations.** As described in more detail in the RTC, EPA disagrees with the notion that CAA sections 169A(b)(2) and (g)(1) and the RHR prohibit States from foregoing a four-factor analysis based on a State determination that a source is effectively controlled. As outlined in the 2017 RHR preamble, "the EPA has consistently interpreted the CAA to provide States with the flexibility to conduct four-factor analyses for specific sources, groups of sources or even entire source categories, depending on State policy preferences and the specific circumstances of each State."[5] However, within the bounds of the flexibility afforded to States, EPA also stated that States must "exercise reasoned judgment when choosing which sources, groups of sources or source categories to analyze."[6] In the 2019 Guidance, section 3(f), EPA explained when it may be appropriate to forgo a four-factor analysis for sources with existing effective control measures and provided examples where a full four-factor analysis would likely result in the conclusion that no further controls are necessary.[7] EPA evaluated Indiana's Regional Haze SIP submission and concludes that IDEM's source selection methodology, thresholds, and justification for not conducting a four-factor analysis on all sources for this second implementation period are reasonable. EPA also concludes that IDEM sufficiently demonstrated that the sources selected for further evaluation at the facilities listed

[5] 82 FR 3088, January 10, 2017.
[6] 82 FR 3088, January 10, 2017.
[7] *See* section 3(f) of EPA's "Guidance on Regional Haze State Implementation Plans for the Second Implementation Period," EPA Office of Air Quality Planning and Standards, Research Triangle Park, August 20, 2019 (2019 Guidance) which is publicly available at *https://www.epa.gov/sites/default/files/2019-08/documents/8-20-2019_-_regional_haze_guidance_final_guidance.pdf.*

under this comment below are effectively controlled for the second implementation period.

***Comment and Response 14b*: Duke – Gibson.** The Conservation Groups assert that excluding Duke – Gibson Unit 5 from LADCO's emissions projections in the 2028 visibility modeling was arbitrary and unlawful since there is no legal requirement preventing the unit from continuing to operate beyond 2028. The Conservation Groups further state that the existing NO_X and SO_2 emission controls on Duke – Gibson Units 1, 2, 3, 4, and 5 are underperforming and that upgrades to the existing controls would likely be feasible and cost-effective.

As described in further detail in the RTC, EPA disagrees with this comment and notes that the assumptions used in modeling future projections were based on the best available information at the time. Although there is no current legal obligation for Unit 5 to retire, EPA continues to find that IDEM has sufficiently demonstrated that Units 1, 2, 3, 4, and 5 are effectively controlled for the second implementation period and that a four-factor analysis would not likely result in the conclusion that further controls are necessary for reasonable progress. In this regard, consistent with the 2019 Guidance, IDEM showed that the SO_2 emission rates for all units are below the 2012 Mercury and Air Toxics Standards (MATS) for coal-fired EGUs. Additionally, NO_X emission rates are below the 0.08 pounds per million metric British thermal units (lbs/MMBtu) level for EGUs with optimized selective catalytic reduction (SCR) under the Revised Cross-State Air Pollution Rule (CSAPR) Update,[8] flue gas desulfurization (FGD) control efficiencies are greater than 90 percent, and SCR control efficiencies are greater than 80 percent.

***Comment and Response 14c*: Alcoa – Warrick Power Plant.** The Conservation Groups argue that Indiana should conduct a four-factor analysis on Alcoa – Warrick Power Plant's Units 1, 2, 3, and 4.

As described in further detail in the RTC, EPA disagrees with this comment and notes that IDEM has sufficiently demonstrated that Alcoa – Warrick Power Plant Units 1, 2, 3 and 4 are effectively controlled for the second implementation period. All four units are subject to BART emission limitations from the first implementation period on a pollutant-specific basis and continue to operate BART controls. Thus, as described in the 2019 Guidance, although BART-eligible sources should not be categorically excluded from further analysis in each planning period, the source is currently operating controls to meet BART emission limits, and it is unlikely that there will be further available reasonable controls. Based on the information

[8] *See* 86 FR 23054, 23088, April 30, 2021.

provided in Indiana's SIP submission and the BART analysis, IDEM appropriately demonstrated that a full four-factor analysis would likely result in the conclusion that no further controls are necessary.

Comment and Response 14d: **AEP – Rockport.** The Conservation Groups state that the existing NO_X and SO_2 emission controls on AEP – Rockport Units 1 and 2 are underperforming and that a four-factor analysis should have been performed.

As further explained in the RTC, EPA disagrees with this comment and maintains that IDEM has sufficiently demonstrated that AEP - Rockport MB1 and MB2 are effectively controlled for the second implementation period. In this regard, as described in the 2019 Guidance, IDEM showed that with the recent installation of enhanced dry sorbent injection (DSI) and SCR on MB2, the SO_2 emission rates for both boilers are below the 0.2 lbs/MMBtu level for coal-fired EGUs in the 2012 MATS, and NO_X emission rates are below the 0.08 lbs/MMBtu level for units with SCR under the Revised CSAPR Update.

Comment and Response 14e**: IKEC – Clifty Creek.** The Conservation Groups argue that additional cost-effective NO_X and SO_2 emission controls are likely to exist for IKEC – Clifty Creek's six EGUs and that a four-factor analysis should have been performed.

As described in greater detail in the RTC, EPA disagrees with this comment and maintains that IDEM has sufficiently demonstrated that IKEC - Clifty Creek Units 1 – 6 are effectively controlled for the second implementation period as described in the 2019 Guidance, with FGDs achieving 98 percent SO_2 control efficiency, SCRs and overfire air achieving 70-90 percent NO_X control on an annual basis, and actual SO_2 emission rates for all six units below the 2012 MATS level for coal-fired EGUs. Additionally, IDEM has thoroughly documented NO_X emissions that are progressively constrained on an annual basis under the Revised CSAPR Update Rule and the lack of potential controls for NO_X that IDEM considers cost-effective.

Comment and Response 14f: **Duke – Cayuga.** The Conservation Groups argue that Indiana should be required to conduct a four-factor analysis on Duke – Cayuga's two coal-fired EGUs Units 2 and 3 and that cost-effective options for additional NO_X emission controls would likely be cost-effective.

As explained in greater detail in the RTC, EPA disagrees with this comment and maintains that IDEM has sufficiently demonstrated that Duke – Cayuga Units 2 and 3 are effectively controlled for the second implementation period. In this regard, as described in the 2019 Guidance, IDEM documented FGD systems achieving 95 percent control efficiency, SO_2 rates that are below MATS for coal fired units, and NO_X emissions that are controlled by low-NOx burners with separated over fire air and

SCR achieving 88 percent control efficiency.

Comment and Response 15: The Conservation Groups contend that EPA neglected its duty to review Indiana's source-specific four-factor analyses. The Conservation Groups also argue that IDEM did not rigorously analyze controls that the Conservation Groups maintain are likely cost effective and, in so doing, did not appropriately require additional control measures for any of the nine sources IDEM evaluated to reduce emissions to make reasonable progress. The nine sources include: (a) Lone Star Industries, Inc. – Greencastle dba Buzzi Unicem USA; (b) Cleveland-Cliffs Steel, LLC – Indiana Harbor East and Indiana Harbor West; (c) Cleveland-Cliffs Steel, LLC – Burns Harbor; (d) U.S. Steel – Gary Works; (e) SABIC Innovative Plastics – Mt. Vernon, LLC; (f) Warrick Newco LLC, formerly Alcoa Warrick Operations, LLC; (g) Cokenergy, LLC; and (h) Heidleberg Materials US Cement LLC – Mitchell Plant, formerly Lehigh Cement Company, LLC – Mitchell Plant.

As further explained in the RTC and as outlined in our NPRM and April 22, 2025, TSD, EPA carefully evaluated Indiana's 2021 SIP submission along with the comments from the Federal Land Managers (FLMs) consultation and the State's public notice period, as well as the State's responses to those comments. Based on the complete record, EPA explained its decision to approve the SIP and took comment on the proposed approval in the

NPRM. EPA recognizes that IDEM worked directly with the sources to conduct extensive site-specific technical work and provide full documentation in support of its 2021 SIP to submit complete four-factor analyses evaluating potential feasible and reasonable control measures. In the NPRM and April 22, 2025, TSD, EPA documented the existing controls, permit limitations, control options, potential reductions, and potential costs for new controls that the State relied upon in its four-factor analyses. In making its determinations, IDEM properly considered the four statutory factors along with projected 2028 visibility conditions for Class I areas influenced by emissions from Indiana sources, emission reductions that have occurred, and current control technologies in concluding no additional controls were necessary to make reasonable progress.

Comment and Response 15a: **Lone Star Industries, Inc. – Greencastle dba Buzzi Unicem USA.** The Conservation Groups state that IDEM's four-factor analysis should have also evaluated SCR and lacked documentation with the consideration of selective non-catalytic reduction for the remaining useful life and interest rate in the cost calculations. The Conservation Groups also contend that Indiana reached its conclusions before the FLM consultation period and the public comment period.

As explained in detail in the RTC, EPA disagrees and notes that IDEM did consider SCR in determining feasible control options. For each control option evaluated, IDEM also provided extensive site-specific documentation, including an explanation of the control technologies, applicability, the limitations, expected removal efficiencies and performance, as well as considerations for cost analyses for both capital and operating costs and the relationship with reduction efficiency.

Further, EPA disagrees with the Conservation Groups' allegations that IDEM failed to incorporate FLM comments in its planning. EPA believes IDEM genuinely and consistently portrayed its intentions by clearly stating, "it is important to address the FLMs comments as thoroughly as possible to show that Indiana has seriously evaluated the selected sources..."[9] EPA finds in this final rulemaking that Indiana has satisfied the consultation and public notice requirements of 40 CFR 51.102 and 51.308(i).

Comment and Response 15b: **Cleveland-Cliffs Steel, LLC – Indiana Harbor East and Indiana Harbor West.** In addition to the potential controls examined in the four-factor analyses, the Conservation Groups assert that IDEM should have evaluated additional emission controls for the No. 5 Boiler House, Blast Furnace Stoves, Lime Kilns, and Walking Beam Furnaces.

As described in further detail in the RTC, EPA disagrees

[9] Appendix P, p.3 of Indiana's 2021 SIP submission.

with this comment and notes that IDEM explained that Indiana Harbor East and Indiana Harbor West identified control measures that were commercially demonstrated on similar applications by searching air permits for other iron and steel mills and other similar sources, the Nucor 2010 Best Available Control Technology (BACT) analysis,[10] as well as EPA's Reasonably Available Control Technology (RACT), BACT, and Lowest Achievable Emission Rate (LAER) Clearinghouse (RBLC).[11] The RBLC contains case-specific information on the "best available" air pollution technologies that have been required to reduce the emission of air pollutants from stationary sources. EPA maintains that IDEM's approach produced an extensive list of control measures relevant to the industry that had proven effective for certain applications and identified a thorough set of control measures for evaluation.

Regarding the cost analyses, IDEM and Cleveland-Cliffs Steel, LLC provided a thorough explanation, justification, and documentation of the cost parameters used in four-factor analyses as well as in its responses to the comments from the FLMs that appropriately considered site-specific factors. The

[10] Nucor Steel Louisiana "Consolidated Environmental Management Inc. – Nucor Steel Louisiana, Best Available Control Technology Analyses," March 1, 2010 (Nucor 2010 BACT).
[11] EPA's RBLC is available through *https://cfpub.epa.gov/rblc/index.cfm?action=Home.Home and https://www.epa.gov/catc/ractbactlaer-clearinghouse-rblc-basic-information.*

Conservation Groups provided their own cost calculations, but their estimates did not include site-specific factors.

Comment and Response 15c: **Cleveland-Cliffs Steel, LLC – Burns Harbor.** In addition to the emission control options examined in the four-factor analysis, the Conservation Groups assert that IDEM should have evaluated additional options for the Coke Batteries, Coke Ovens, and Coke Oven Gas Export Line as well as provided better documentation for parameters such as the remaining useful life and interest rate in the cost calculations.

As discussed further in the RTC, EPA disagrees with this comment and notes that IDEM provided sufficient documentation and identified control measures that were commercially demonstrated on similar applications by searching air permits for other iron and steel mills and other similar sources, the Nucor 2010 BACT analysis, as well as EPA's RBLC. EPA notes that IDEM's approach produced an extensive list of control measures relevant to the industry that had proven effective for certain applications and identified a thorough set of control measures for evaluation. For the Coke Batteries, Coke Ovens, and Coke Oven Gas Export Line, the four-factor analysis search found no examples where SCR or wet scrubbers had been installed and successfully operated to control NO_X and SO_2 emissions under similar physical and operating conditions to those at Burns

Harbor.[12]

Although the Conservations Groups assert that the cost analyses lacked documentation, IDEM and Cleveland-Cliffs Steel, LLC provided a thorough explanation, justification, and documentation of the cost parameters used in the four-factor analysis and in its responses to the comments from the FLMs.

Comment and Response 15d: **U.S. Steel – Gary Works.** In addition to the emission control options examined in the four-factor analysis, the Conservation Groups assert that IDEM should have evaluated SCR for the 84" Strip Mill Reheat Furnace and used different values in the cost analysis for low-NOx burners on the Waste Heat Boilers 1 and 2.

As described in more detail in the RTC, EPA disagrees with this comment. EPA notes that IDEM identified control measures that were commercially demonstrated on similar applications by searching air permits for other iron and steel mills and other similar sources, the Nucor 2010 BACT analysis, and EPA's RBLC. However, IDEM's search did not find a SCR that had been installed and successfully operated on a similar source and under similar operating conditions as Gary Works.

Regarding the cost analyses for low-NO_X burners for Waste Heat Boiler 1, although the Conservations Groups provided their

[12] For lists obtained during the search of EPA's RBLC and air permits, *see* appendices A and B of appendix B of appendix I to Indiana's 2021 SIP submission.

own cost calculations using different parameters, EPA notes that IDEM and U.S. Steel – Gary Works provided a thorough explanation, justification, and documentation of the cost parameters used in the four-factor analysis[13] and in its responses to the comments from the FLMs[14] that appropriately considered site-specific factors that the Conservation Groups' estimates did not.

Comment and Response 15e: **SABIC Innovative Plastics – Mt. Vernon, LLC.** The Conservation Groups assert that IDEM's four-factor analysis lacked consideration of all emission sources besides the Co-generation Unit and COS Vent Oxidizer as well as appropriate assumptions for costs and remaining useful life.

As detailed further in the RTC, EPA disagrees with this comment and notes that of the emission sources listed in the facility's title V permit,[15] the Co-generation Unit accounted for the largest portion of the facility's total potential to emit NO_X at 39 percent. Based on this, EPA agrees that IDEM appropriately focused its evaluation of potential emission reduction for NO_X on the Co-generation Unit rather than the emissions from the other boilers and units. Although the

[13] *See* section 13.10, 13.11, 13.12 and appendices I and J of Indiana's 2021 SIP submission.
[14] *See* appendix S to Indiana's 2021 SIP submission.
[15] Title V Permit 129-45722-00002 for SABIC Innovative Plastics – Mt. Vernon, LLC issued June 16, 2023, is publicly available at *https://permits.air.idem.in.gov/45722f.pdf.*

Conservation Groups assert that IDEM did not provide underlying calculations and supporting information, EPA notes that the four-factor analysis provided a solid basis for calculating the total capital investment and cost effectiveness and documentation was provided in Section 15 and appendices I and J of Indiana's 2021 SIP submission.

Comment and Response 15f: **Warrick Newco LLC, formerly Alcoa Warrick Operations, LLC.** The Conservation Groups assert that the four-factor analysis should have evaluated NO_X emissions as well as SO_2 emissions and provided better documentation for figures used in the cost calculations.

As discussed in further detail in the RTC, EPA disagrees with this comment and notes that NO_X emissions from Alcoa Warrick Operations, LLC represented the lowest levels of all the sources that IDEM evaluated for a four-factor analysis. As such, IDEM's decision at the time to focus resources on addressing potential controls in the second implementation period for only SO_2 was well reasoned. EPA also determined that IDEM provided sufficient relevant documentation for the economic and emissions information used in the four-factor analysis.

Comment and Response 15g: **Cokenergy, LLC.** The Conservation Groups claim that the four-factor analysis was not a four-factor analysis, but rather a recitation of studies and projects, and should have also evaluated DSI and upgrades to other existing systems.

As further addressed in the RTC, EPA disagrees with this comment and notes that the summaries of the previous studies and projects served to develop a set of technically feasible control options for evaluation and that the four-factor analysis then addressed each of the statutory four factors in turn. Although the Conservation Groups assert that several other specific options should have been addressed, many of those suggested by the Conservation Groups were considered during the course of the studies mentioned above, including evaluations of installing or upgrading DSI, spray dryer absorbers, and atomizers. EPA notes that these options, along with the other options evaluated, represented a reasonable selection of control options.

Comment and Response 15h: **Heidleberg Materials US Cement LLC – Mitchell Plant, formerly Lehigh Cement Company, LLC – Mitchell Plant.** The Conservation Groups note that IDEM selected this source for a four-factor analysis but did not complete one.

As described in additional detail in the RTC, EPA notes that, pursuant to an amended Federal consent decree,[16] Lehigh

[16] *See USA, State of Indiana, State of Iowa, State of Maryland, State of New York, Pennsylvania Department of Environmental Protection, Jefferson County Board of Health, and Bay Area Air Quality Management District v. Lehigh Cement Company, LLC and Lehigh White Cement Company, LLC,* Civil Action No. 5:19-cv-05688-JFL in United States District Court, Eastern District of Pennsylvania. The initial and amended consent decrees are available in the docket and at *https://www.justice.gov/enrd/consent-decree/file/1223121/dl*; *https://www.justice.gov/enrd/consent-decree/file/1352971/dl*.

will be permanently ending operations of Kilns 1, 2, and 3 by the end of 2025. In the future, Lehigh will be installing and operating SCR and meeting the NSPS for Portland Cement Plants (40 CFR 60, subpart F) for any new kilns.

Comment and Response 16: The Conservation Groups argue that source-specific BART determinations in the first implementation period need to be reassessed. Under 42 USC 7491(b)(2)(A), the Conservation Groups state that the CAA established BART as a mandatory part of "each applicable implementation plan" for "each" BART-eligible source that emits "any" air pollutant which may cause or contribute to "any" impairment of visibility in "any" Class I area.

As explained further in the RTC, EPA disagrees that States are required to conduct BART analyses anew in the second regional haze implementation period and onward. Specifically, EPA disagrees that its second implementation period regulations require a BART analysis for second implementation period SIPs. Pursuant to 40 CFR 51.308(e)(5), once Indiana satisfied the BART requirements in the first implementation period, Indiana's BART-eligible sources were then subject to the long-term strategy requirements in 40 CFR 51.308(f) for the second implementation period. As stated throughout our proposal and this final action, EPA finds that Indiana properly met the long-term strategy requirements of 40 CFR 51.308(f) in the second implementation period.

Comment and Response 17: The Conservation Groups assert that EPA should analyze the impact of Indiana regional haze pollution on local communities since the same pollutants contributing to regional haze also contribute disparately to public health impacts on people residing closest to the sources. The Conservation Groups state that people living in these communities tend to be exposed to higher levels of particulate matter and NO_X and tend to have less access to quality health care to treat the impacts of environmental pollution.

As discussed in more detail in the RTC, with respect to public health concerns, the primary national ambient air quality standards provide public health protection. In contrast, the visibility program, prescribed by CAA sections 169A and 169B and implemented in 40 CFR 51.308, is not a health-based program. EPA is acting upon Indiana's 2021 Regional Haze SIP submission as required by regional haze regulations at 40 CFR 51.308.

Comment and Response 23: The Conservation Groups commented that EPA must withdraw its proposal to approve Indiana's 2021 SIP Revision and disapprove it.

For the reasons stated in the NPRM, EPA's April 22, 2025, TSD, EPA's December 19, 2025, RTC, this notice of final rulemaking, and the foregoing summary of responses to comments in this docket, EPA disagrees that Indiana failed to satisfy the requirements of the CAA and RHR. EPA also disagrees that EPA's proposed approval of Indiana's 2021 SIP Revision was fundamentally flawed in such a way as to make it ineffective at achieving reasonable progress in the second implementation period. Thus, as proposed in the NPRM, EPA is finalizing its approval of Indiana's 2021 SIP Revision as satisfying the applicable requirements under the CAA and RHR for the program's second implementation period.

C. Comments and Responses that are specific to EPA's URP Policy

EPA received several comments regarding EPA's URP policy. Comments from IDEM (Comment 6), PGen (Comment 7), Utilities for Reasonable Progress (Comment 8), and OVEC and IKEC (Comment 9) were supportive of EPA's URP policy. Comments from the Community Organizations (Comment 10b), MANEVU (Comment 11a) and the Conservation Groups (Comments 18 - 22) were opposed to EPA's URP policy.

In this final action, EPA is affirming that it is now the Agency's policy that, where visibility conditions for a Class I Federal area impacted by a State are below the URP and the State has considered the four statutory factors, the State will have presumptively demonstrated reasonable progress for the second implementation period for that area. EPA acknowledges that this final action reflects a change in policy as to how the URP should be used in the evaluation of regional haze second implementation period SIPs but believes that this policy better aligns with the purpose of the statute and RHR: achieving "reasonable" progress towards natural visibility.

As described in the approval of West Virginia's regional haze plan (90 FR 29737, July 7, 2025), EPA has discretion and authority to change its policy. In *FCC* v. *Fox Television Stations, Inc.*, the U.S. Supreme Court plainly stated that an agency is free to change a prior policy and "need not demonstrate ... that the reasons for the new policy are better than the reasons for the old one; it suffices that the new policy is permissible under the statute, that there are good reasons for it, and that the agency believes it to be better." 556 U.S. 502, 515 (2009) (referencing Motor *Vehicle Mfrs. Ass'n of United States, Inc.* v. *State Farm Mut. Auto. Ins. Co.*, 463 U.S. 29 (1983)). *See also Perez* v. *Mortgage Bankers Assn.*, 135 S. Ct. 1199 (2015).

The Class I areas impacted by emissions from Indiana sources are all below the 2028 URP, and IDEM's SIP submission demonstrated that the State took into consideration the four reasonable progress factors listed in CAA 169A(g)(1)[17] with respect to an adequate number of emissions sources. Thus, EPA

[17] The four statutory factors required to be taken into consideration in determining reasonable progress are: the costs of compliance, the time necessary for compliance, and the energy and non-air quality environmental impacts of compliance, and the remaining useful life of any existing source subject to such requirements. CAA section 169(g)(1).

determines that Indiana's SIP revision is fully approvable under the Agency's new URP policy. Indeed, we think this policy better aligns with the statutory goal because it recognizes the considerable improvements in visibility impairment that have been made by a wide variety of State and Federal programs in recent decades.

In developing the regulations required by CAA section 169A(b), EPA established the concept of the URP for each Class I area. The URP is determined by drawing a straight line from the measured 2000 to 2004 baseline conditions (in deciviews) for the 20 percent most impaired days at each Class I area to the estimated natural conditions (in deciviews) for the 20 percent most impaired days in 2064. From this calculation, a URP value can be calculated for each year between 2004 and 2064. EPA developed the URP to address the diverse concerns of Eastern and Western States and account for the varying levels of visibility impairment in Class I areas around the country while ensuring an equitable approach nationwide. For each Class I area, States must calculate the URP for the end of each planning period (*e.g.*, in 2028 for the second implementation period).[18] 40 CFR

[18] We note that RPGs are a regulatory construct that we developed to address the statutory mandate in CAA section 169B(e)(1), which required our regulations to include "criteria for measuring 'reasonable progress' toward the national goal." Under 40 CFR 51.308(f)(3)(ii), RPGs measure the progress that is projected to be achieved by the control measures a State has determined are necessary to make reasonable progress. Consistent with the 1999 RHR, the RPGs are unenforceable, though they create a benchmark that allows for analytical comparisons to the URP and mid-implementation-period course corrections if necessary. 82 FR 3091-3092 (January 10, 2017).

51.308(f)(1)(vi)(A). States may also adjust the URP to account for impacts from anthropogenic sources outside the United States and/or impacts from certain wildland prescribed fires. 40 CFR 51.308(f)(1)(vi)(B). Then, for each Class I area, States must compare the reasonable progress goal (RPG) for the 20 percent most impaired days to the URP for the end of the planning period. If the RPG is above the URP, then an additional "robust demonstration" requirement is triggered for each State that contributes to that Class I area. 40 CFR 51.308(f)(3)(ii)(B).

In the 2017 RHR Revisions, EPA addressed the role of the URP as it relates to a State's development of its second implementation period SIP. 82 FR 3078 (January 10, 2017). Specifically, in response to comments suggesting that the URP should be considered a "safe harbor" that relieves States of any obligation to consider the four statutory factors, EPA explained that the URP was not intended to be such a safe harbor. *Id.* at 3099. "Some commenters stated a desire for corresponding rule text dealing with situations where RPGs are equal to ('on') or better than ('below') the URP or glidepath. Several commenters stated that the URP or glidepath should be a 'safe harbor,' opining that States should be permitted to analyze whether projected visibility conditions for the end of the implementation period will be on or below the glidepath based on on-the-books or on-the-way control measures, and that in such cases a four-factor analysis should not be required." *Id.*

Other comments indicated a similar approach, such as "a somewhat narrower entrance to a 'safe harbor,' by suggesting that if current visibility conditions are already below the end-of-planning-period point on the URP line, a four-factor analysis should not be required." *Id.* EPA stated in its response that we did not agree with either of these recommendations. "The CAA requires that each SIP revision contain long-term strategies for making reasonable progress, and that in determining reasonable progress States must consider the four statutory factors. Treating the URP as a safe harbor would be inconsistent with the statutory requirement that States assess the potential to make further reasonable progress towards natural visibility goal in every implementation period." *Id.*

Importantly, EPA's recently adopted policy does not make the URP a safe harbor. The policy merely creates a presumption that the State's second implementation period SIP is making reasonable progress for a Class I Federal Area if the State has taken into consideration the four statutory factors of 169A(g)(1) and that area is below the URP. This is consistent with the CAA and RHR.

Comment and Response 11a: Instead of relying on the RPGs, MANEVU asserts EPA's URP policy is not permissible and that EPA is now using the URP as the determinative metric, to ignore the extensive work of the States, the FLMs, and the public in developing the RPGs.

As discussed further in the RTC, EPA disagrees with MANEVU's comment. EPA's URP policy does not ignore the results of a State's four-factor analysis if a Class I area is below the URP. Consistent with EPA's discussion under the preamble of the 2017 RHR, the URP continues to serve as a regulatory planning metric to inform States' decision making when considering the four statutory factors. EPA's URP policy recognizes the considerable improvements in visibility impairment that have been made by State and Federal programs resulting from decades of work and interaction between members of State and Federal agencies and the public.

Comment and Response 18: The Conservation Groups argue that EPA's URP Policy violates the CAA's visibility provisions. The Conservation Groups raise several issues pertaining to EPA's URP policy: a) EPA's URP policy violates the plain language of the CAA, b) EPA's contemporaneous understanding of the CAA reflects the best reading of the statute, c) the context of the CAA's visibility provisions confirms the best reading of the statute, and d) the purpose of the CAA's visibility provisions confirms the best reading of the statute.

EPA disagrees with each of these comments, including the

Conservation Groups' position that the URP policy articulated in our proposed approval of Indiana's regional haze SIP submission is inconsistent with the CAA. The Conservation Groups' reading of the statute is not the best, and they misconstrue the recently adopted policy in several ways. EPA notes that the comments and responses on each above point are presented in detail in the RTC document.

EPA's new URP policy is consistent with the CAA. Pursuant to CAA 169A(a)(4), Congress explicitly delegated to EPA the authority to promulgate regulations regarding reasonable progress towards meeting the national goal. In determining the measures necessary to make reasonable progress, Congress mandated "tak[ing] into consideration the cost of compliance, the time necessary for compliance, and the energy and nonair quality environmental impacts of compliance, and the remaining useful life of any existing source subject to such requirement." CAA 169A(g)(1).

EPA emphasizes that just because a Class I area is below the URP does not mean that a State is relieved of its obligations under the CAA and the RHR to make reasonable progress. In other words, the URP is not a "safe harbor," as that phrase has sometimes been used, because EPA still must review a State's determination whether additional control measures are necessary to make reasonable progress, determine whether the State submitted those measures for incorporation into the SIP, and evaluate whether the measures are consistent with other provisions in the CAA.

As required by the statute, Indiana took into consideration the four statutory factors in CAA section 169A(g)(1) and determined that no additional controls were necessary to make reasonable progress at the sources selected. CAA section 169A(b)(2) only requires SIPs to include "such emission limits, schedules of compliance and other measures *as may be necessary* to make reasonable progress" (emphasis added). IDEM concluded that it was not necessary to incorporate any new emission limits, schedules of compliance, or other measures into its SIP in light of the progress already made.

Comments and Responses 10 and 19: Both the Community Organizations and Conservation Groups argued that EPA's URP policy is inconsistent with the RHR.

As discussed in the RTC, EPA disagrees with the commenters' position that the URP policy is inconsistent with the RHR. This comment tracks many of the issues commenters raised with respect to their allegations that EPA's recently adopted URP policy is inconsistent with the CAA. Under the URP policy, and consistent with 40 CFR 51.308(f)(2), States are still required to identify measures necessary for reasonable progress by considering the four statutory factors set forth in CAA 169A(g)(1) and to submit measures necessary for reasonable progress to EPA to be reviewed for approvability into the SIP. The URP policy does not create an exemption to either of these provisions.

Comment and Response 20: The Conservations Groups comment that EPA's articulation and application of its new URP policy is unclear and incoherent. In this regard, the Conservation Groups argue: (a) Mere consideration of the four factors is inconsistent with the CAA and the RHR and is fundamentally irrational, (b) EPA fails to explain why a four-factor analysis must be rational when, under the URP policy, its result does not matter and EPA does not substantively review it, and (c) EPA further muddies the waters by considering other factors in an arbitrary and capricious way.

As discussed in detail in the RTC for Responses 20a, 20b, and 20c, EPA disagrees with the Conservation Groups' arguments mentioned above regarding EPA's application of the URP policy being unclear and incoherent. EPA's recently adopted policy is consistent with the CAA and is not arbitrary or capricious. The Conservation Groups incorrectly assert that the URP policy ignores the results of a State's four-factor analysis if a Class I area is below the URP. Just because a Class I area is below the URP does not mean that a State is relieved of its obligations under the CAA and the RHR to make reasonable progress. EPA must still review a State's determination whether additional control measures are necessary to make reasonable progress, determine whether the State submitted those measures for incorporation into the SIP, and evaluate whether the measures are consistent with other provisions in the CAA.

Comment and Response 21: The Conservation Groups assert that announcing and applying EPA's new URP policy in state-specific regional actions violates the procedural requirements of the CAA under 306(a)(2) regarding consistency among Regional Offices in implementing the CAA. The Conservation Groups argue that EPA's URP policy unlawfully departs from national policy and is inconsistent with actions across EPA regions.

EPA disagrees with the Conservation Groups' position here as further explained in the RTC. EPA's change in policy is consistent with *FCC v. Fox Television*, 556 U.S 502 (2009). Under *FCC v. Fox*, an agency's change in policy is permissible if the agency acknowledges the change, believes it to be better, and "show[s] that there are good reasons for the new policy." 556 U.S. at 515. We stated our reasons for implementing the recently adopted URP policy in the final action approving the West Virginia SIP for the second implementation period. 90 FR 29737 (Jul. 7, 2025). The reasons for the recently adopted policy were more fully articulated in section V, *The EPA's Rationale for Proposing Approval*, of that proposal. 90 FR 16478 (Apr. 18, 2025). Therefore, EPA has sufficiently justified the change in policy under *FCC* v. *Fox.*

The decision in *FCC* v. *Fox* turned primarily on whether the FCC's change in policy would lead to the FCC "arbitrarily punishing parties without notice of the potential consequences of their action." 556 U.S. at 517. The changed policy is prospective, which addresses the primary concern in *FCC* v. *Fox.* Additionally, the recently adopted URP policy "aligns with the purpose of the statute and RHR, which is achieving `reasonable' progress, not maximal progress, toward Congress' natural visibility goal." 90 FR 16478, at 16483. Furthermore, we note that the legislative history of CAA section 169A is consistent with our change in policy. The reconciliation report for the 1977 CAA amendments indicates that the term "maximum feasible progress" in section 169A was changed to "reasonable progress" in the final version of the legislation passed by both chambers. *See* Legislative History of the CAA Amendments of 1977 Public Law 95-95 (1977), *H.R. Rep. No. 95-564,* at 535.

EPA notes that EPA's Regional Consistency regulations at 40 CFR part 56, and in particular 40 CFR 56.5(b), are not relevant to this action. 40 CFR 56.5(b) requires that a "responsible official in a Regional office shall seek concurrence from the appropriate EPA Headquarters office on any interpretation of the Act, or rule, regulation, or program directive when such interpretation may result in application of the act or rule, regulation, or program directive that *is inconsistent* with Agency policy" (emphasis added). As we expressly indicated in the proposal for this action, the approval is *consistent* with the change in agency policy, first announced in *Air Plan Approval; West Virginia; Regional Haze State Implementation Plan for the Second Implementation Period*. 90 FR 16478 (Apr. 18, 2025). Therefore, there is no obligation under the EPA's Regional Consistency regulations for anyone in the region to seek concurrence from EPA Headquarters to take action consistent with EPA policy. The lack of relevance of these regulations to this action accounts for the lack of materials related to compliance with the Regional Consistency process in the docket for this rulemaking.

The Conservation Groups also argue that EPA's URP policy effectively revises the RHR and raises the question of whether it has nationwide scope and effect.

EPA disagrees with the Conservation Groups' comment here as further explained in the RTC. EPA notes that this action is "locally or regionally applicable" under CAA section 307(b)(1) because it applies only to a SIP submission from a single State, Indiana. *See Oklahoma* v. *EPA,* 605 U.S. 609, 620 (2025) (a SIP is "a state-specific plan" and "the CAA recognizes this limited scope in enumerating a SIP approval as a locally or regionally applicable action"); *see also, Am. Rd. & Transp. Builders Ass'n,* 705 F.3d 453, 455 (D.C. Cir. 2013) (describing EPA action to approve a single SIP under CAA section 110 as the "[p]rototypical" locally or regionally applicable action).

Whether our proposal to approve Indiana's second implementation period SIP relies on a new national policy has no bearing on the applicability of EPA's final action. To determine whether an action is "nationally applicable" or "locally or regionally applicable," "court[s] need look only to the face of the agency action, not its practical effects . . . ." *EPA* v. *Calumet Shreveport Refining, L.L.C.,* 605 U.S. 627, 642 (2025) ("[W]e determine an action's range of applicability by 'look[ing] only to the face of the [action], rather than to its practical effects.'") (quoting *Am. Rd. & Transp. Builders Ass'n,* 705 F.3d at 456) and *Oklahoma,* 605 U.S. at 621-622 (basis for EPA action is not relevant to determining its applicability); *see also Sierra Club* v. *EPA,* 926 F.3d 844, 849 (D.C. Cir. 2019) and *RMS of Georgia, LLC* v. *EPA,* 64 F.4th 1368, 1372 (11th Cir. 2023) ("our sister circuits have established a consensus that we should begin our analysis by analyzing the nature of the EPA's action, not the specifics of the petitioner's grievance").

Furthermore, the comments that claim the recently adopted URP policy "amend[s] the nationally applicable RHR" are unsupported and incorrect. This action simply applies our recently adopted policy related to the URP in the context of

EPA's evaluation of Indiana’s regional haze SIP submission. Because this action applies a recently adopted policy to a SIP submission from Indiana alone, it is locally or regionally, not nationally, applicable.

Comments that claim that EPA “must” publish a finding that this action is “based on a determination of nationwide scope [or] effect” are also unsupported and incorrect. The Supreme Court has recognized that “[b]ecause the ‘nationwide scope or effect’ exception can apply only when ‘EPA so finds and publishes’ that it does, EPA can decide whether the exception is even potentially relevant.” *Calumet Shreveport Refining, L.L.C.,* 605 U.S. at 646, citing *Sierra Club* v. *EPA,* 47 F.4th 738, 746 (D.C. Cir. 2022). As the D.C. Circuit has also stated, the “EPA's decision whether to make and publish a finding of nationwide scope or effect is committed to the agency's discretion and thus is unreviewable.” *Sierra Club* v. *EPA,* 47 F.4th at 745; *see also Texas* v. *EPA,* 983 F.3d 826, 835 (5th Cir. 2020) (“when a locally applicable action is based on a determination of nationwide scope or effect, the EPA has discretion to select the venue for judicial review”).

The Administrator has not made and published a finding that this action is based on a determination of nationwide scope or effect. Accordingly, any petition for review of this action must be filed in the United States Court of Appeals for the appropriate regional circuit.

Comment and Response 22: The Conservation Groups comment that Indiana's 2021 SIP submission does not meet EPA's URP policy for presumptive approval. As such, the Conservation Groups argue that Indiana: a) would not be able to meet the RHR monitoring requirements without the IMPROVE network if its continued operation were threatened, b) relies on adjusted URP glidepaths that do not comply with the RHR, and c) ignores additional out-of-state Class I areas affected by visibility impairing emissions from Indiana.

EPA disagrees with these comments as further discussed in the RTC. Indiana met the requirements of the recently adopted policy. First, the RHR requires States to submit a long-term strategy that addresses regional haze visibility impairment for each mandatory Class I Federal area within the State and for each mandatory Class I Federal area located outside the state that may be affected by emissions from the State. 40 CFR 51.308(f)(2); *see also* CAA 169A(b)(2). However, there is no specific statutory or regulatory requirement to identify the precise set of Class I areas that are affected by emissions from Indiana, and there is no requirement to establish a source contribution threshold in identifying those areas. In this case, Indiana identified affected out-of-state Class I areas, none of which are above the 2028 URP.

EPA believes Indiana has reasonably documented its impacts to in-state and out-of-state Class I areas, and they are not reasonably anticipated to cause or contribute to any impairment in any area that is above the URP.

In conclusion, IDEM took into consideration the four statutory factors in CAA section 169A(g)(1) and determined that no additional controls were necessary to make reasonable progress for the specific sources selected for four-factor analyses. CAA section 169A(b)(2) only requires SIPs to include "such emission limits, schedules of compliance and other measures *as may be necessary* to make reasonable progress" (emphasis added). IDEM concluded that it was not necessary to incorporate any new emission limitations, schedules of compliance, or other measures into its SIP for these sources. Thus, IDEM did not ignore the results of its consideration of the four statutory factors; rather, as supported by the recently adopted URP policy, the State properly used the URP to inform its final decision making as to the measures necessary to make reasonable progress in the second implementation period.

D. EPA's Final Approval

EPA determines that Indiana reasonably considered the statutory and regulatory requirements and appropriately determined what measures are necessary for reasonable progress for the second implementation period. As such, EPA finds that

Indiana submitted a Regional Haze SIP revision that meets all the regional haze requirements for the second implementation period.

EPA concludes that Indiana’s determinations of the measures necessary for reasonable progress were based on a reasonable consideration of the four statutory factors. IDEM thoroughly evaluated and determined the emission reduction measures that are necessary to make reasonable progress by considering the four statutory factors. IDEM also documented large statewide emissions reductions achieved during the second implementation period.

EPA is finalizing its approval of Indiana’s December 29, 2021, Regional Haze SIP submission for the second implementation period as proposed.

IV. Final Action

For the reasons set forth in the June 18, 2025, NPRM, the April 22, 2025, TSD, the December 19, 2025, RTC document, and in this final rule, EPA is approving the Regional Haze SIP revision for Indiana submitted by IDEM on December 29, 2021, as satisfying the regional haze requirements for the second implementation period contained in 40 CFR 51.308(f).

V.   Statutory and Executive Order Reviews

Under the CAA, the Administrator is required to approve a SIP submission that complies with the provisions of the CAA and applicable Federal regulations. 42 U.S.C. 7410(k); 40 CFR 52.02(a). Thus, in reviewing SIP submissions, EPA's role is to approve State choices, provided that they meet the criteria of the CAA. Accordingly, this action merely approves State law as meeting Federal requirements and does not impose additional requirements beyond those imposed by State law. For that reason, this action:

- Is not a significant regulatory action subject to review by the Office of Management and Budget under Executive Order 12866 (58 FR 51735, October 4, 1993);
- Is not subject to Executive Order 14192 (90 FR 9065, February 6, 2025) because SIP actions are exempt from review under Executive Order 12866;
- Does not impose an information collection burden under the provisions of the Paperwork Reduction Act (44 U.S.C. 3501 *et seq.*);
- Is certified as not having a significant economic impact on a substantial number of small entities under the Regulatory Flexibility Act (5 U.S.C. 601 *et seq.*);
- Does not contain any unfunded mandate or significantly or uniquely affect small governments, as described in the Unfunded Mandates Reform Act of 1995 (Pub. L. 104-4);
- Does not have federalism implications as specified in

Executive Order 13132 (64 FR 43255, August 10, 1999);

- Is not subject to Executive Order 13045 (62 FR 19885, April 23, 1997) because it approves a State program;
- Is not a significant regulatory action subject to Executive Order 13211 (66 FR 28355, May 22, 2001); and
- Is not subject to requirements of section 12(d) of the National Technology Transfer and Advancement Act of 1995 (15 U.S.C. 272 note) because application of those requirements would be inconsistent with the CAA.

In addition, the SIP is not approved to apply on any Indian reservation land or in any other area where EPA or an Indian Tribe has demonstrated that a Tribe has jurisdiction. In those areas of Indian country, the rule does not have Tribal implications and will not impose substantial direct costs on Tribal governments or preempt Tribal law as specified by Executive Order 13175 (65 FR 67249, November 9, 2000).

This action is subject to the Congressional Review Act, and EPA will submit a rule report to each House of the Congress and to the Comptroller General of the United States. This action is not a "major rule" as defined by 5 U.S.C. 804(2).

Under section 307(b)(1) of the CAA, petitions for judicial review of this action must be filed in the United States Court of Appeals for the appropriate circuit by **[insert date 60 days after date of publication in the *Federal Register*]**. Filing a petition for reconsideration by the Administrator of this final rule does not affect the finality of this action for the purposes of judicial review nor does it extend the time within which a petition for judicial review may be filed, and shall not postpone the effectiveness of such rule or action. This action may not be challenged later in proceedings to enforce its requirements. (See section 307(b)(2).)

List of Subjects in 40 CFR Part 52

Environmental protection, Air pollution control, Incorporation by reference, Intergovernmental relations, Nitrogen dioxide, Ozone, Particulate matter, Sulfur oxides.

Dated: January X, 2026.

Anne Vogel,
Regional Administrator, Region 5.

For the reasons stated in the preamble, title 40 CFR part 52 is amended as follows:

PART 52—APPROVAL AND PROMULGATION OF IMPLEMENTATION PLANS

1. The authority citation for part 52 continues to read as follows:

Authority: 42 U.S.C. 7401 *et seq*.

2. In § 52.770, the table in paragraph (e) is amended by adding a new entry for "Regional Haze Plan for the Second Implementation Period" after the entry for "Regional Haze Plan" to read as follows:

§ 52.770 Identification of plan.

* * * * *

(e) * * *

EPA-APPROVED INDIANA NONREGULATORY AND QUASI-REGULATORY PROVISIONS

Title	Indiana date	EPA approval	Explanation
* * * * * * *			
Regional Haze Plan for the Second Implementation Period	12/29/2021	**[insert the date of publication in the *Federal Register*]**, 91 FR **[insert *Federal Register* page where the document begins]**	Full approval.
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BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c) Emergency Order: Midcontinent Independent System Operator and Northern Indiana Public Service Company LLC	)))))	Order No. 202-26-19
Federal Power Act Section 202(c) Emergency Order: Midcontinent Independent System Operator and CenterPoint Energy Indiana South	))))	Order No. 202-26-20

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

Exhibit 58
MISO Tariff Module E-1

This Module E-1 provides mandatory requirements to be met by the Transmission Provider, Market Participants serving Load in the Transmission Provider Region or serving Load on behalf of a Load Serving Entity (LSE), or other Market Participants, to ensure access to deliverable, reliable and adequate Planning Resources to meet Coincident Peak Demand and Local Resource Zone Peak Demand requirements on the Transmission System. These requirements recognize and are complementary to the reliability mechanisms of the states and the Regional Entities (RE) within the Transmission Provider Region. Nothing in this Module E-1 affects existing state jurisdiction over the construction of additional capacity or the authority of states to set and enforce compliance with standards for adequacy. The Resource Adequacy Requirements (RAR) in this Module E-1 are not intended to and shall not in any way affect state actions over entities under the states' jurisdiction. To the extent that an LSE's Coincident Peak Demand is physically located within the Transmission Provider's Balancing Authority Area but is pseudo-tied out of the MISO Balancing Authority Area pursuant to the Transmission Provider's Business Practices Manuals (BPM), such Coincident Peak Demand is not subject to the RAR provisions if such Coincident Peak Demand is subject to another Balancing Authority Area's resource adequacy requirements. To accomplish these reliability requirements, Module E-1 includes provisions for: establishing Local Resource Zones and associated limits (*i.e.*, Capacity Import Limits (CIL) and Capacity Export Limits (CEL)); establishing Local Reliability Requirements (LRR); establishing Local Clearing Requirements (LCR); establishing External Resource Zones and associated limits (i.e., Capacity Export Limits (CEL)); determining the Planning Reserve Margin; Coincident Peak Demand forecasting; Local Resource Zone Peak Demand forecasting; qualifying and quantifying Planning Resources; participation of Demand and Planning Resources in the Planning Resource

Auction process; settlement provisions; and Planning Resource performance requirements for each Season.

Establishment of Planning Reserve Margins

The Transmission Provider will determine a Planning Reserve Margin (PRM) in terms of Unforced Capacity for each Season using analytical study methods described in Section 68A.2, provided that if a State Regulatory Authority establishes a PRM for its regulated entities that is higher or lower than the PRM determined by the Transmission Provider, then the State Regulatory Authority-established PRM will apply to the Coincident Peak Demand of LSEs under that state's jurisdiction.

Planning Reserve Margin Analysis

The Transmission Provider shall perform a technical analysis on an annual basis to establish the PRM for each Season for the Transmission Provider Region and the Transmission Provider will publish the results by November 1 preceding the applicable Planning Year. The PRM analysis shall be consistent with Good Utility Practice and the reliability requirements of the REs and the applicable states in the Transmission Provider Region. The PRM analysis shall consider factors including, but not limited to: the Generator Forced Outage rates of Capacity Resources; Generator Planned Outages; expected performance of Demand Response Resources (DRR), Load Modifying Resources (LMR), and Energy Efficiency Resources; load forecast uncertainty; and the Transmission System's import and export capability with external systems. The Transmission Provider annually will calculate and publish on its website the estimated PRM for each of the nine subsequent Planning Years, to provide information for long-term resource planning, without establishing any enforceable specific planning reserve requirements.

Loss of Load Expectation Analysis

The Transmission Provider shall coordinate with Market Participants to determine the appropriate PRM for the applicable Season in the Planning Year based upon the probabilistic analysis of being able to reliably serve the Transmission Provider Region's Demand for the applicable Season in the Planning Year. This probabilistic analysis shall use a Loss of Load Expectation (LOLE) study which assumes that there are no internal transmission limitations within the Transmission Provider Region.

The following process will be utilized to determine the minimum PRM requirement for each Season in the Planning Year using the LOLE analysis. First, an LOLE analysis for the Planning Year will be conducted such that the LOLE for the Planning Year is one (1) day in ten (10) years, or 0.1 day per year, by either adding or removing capacity. If the LOLE for the Planning Year is less than 0.1 day per year, a perfect negative unit with zero forced outage rate will be added until the LOLE reaches 0.1 day per year. If the LOLE for the Planning Year is greater than 0.1 day per year, proxy units based on a unit of typical size and forced outage rate will be added to the model until the LOLE reaches 0.1 day per year. If the LOLE for a Season is equal to or greater than 0.01 day per year, the minimum PRM requirement for that Season will be calculated based on this LOLE analysis. If the LOLE for any Season is less than 0.01 day per year, an additional LOLE analysis will be performed to determine minimum PRM requirement for that Season by adding a perfect negative unit with zero forced outage rate to that Season until the LOLE in that Season reaches 0.01.

The minimum amount of capacity above Coincident Peak Demand in the Transmission Provider Region required to meet the reliability criteria will be used to establish the PRM for each Season.

The PRM will be established as a requirement in terms of the total Unforced Capacity for the Transmission Provider Region.

No later than September 1st of the year prior to a Planning Year, the Transmission Provider will, as necessary, develop new Local Resource Zones (LRZ) to reflect the need for an adequate amount of Planning Resources to be located in the right physical locations within the Transmission Provider Region to reliably meet Demand and LOLE requirements. The geographic boundaries of each of the LRZs will be based upon analysis that considers: (1) the electrical boundaries of Local Balancing Authorities; (2) state boundaries; (3) the relative strength of transmission interconnections between Local Balancing Authorities; (4) the results of LOLE studies; (5) the relative size of LRZs; and (6) natural geographic boundaries such as lakes and rivers. The Transmission Provider may re-evaluate the boundaries of LRZs if there are significant changes in the Transmission Provider Region based upon the preceding factors, including but not limited to, significant changes in membership, the Transmission System, and/or Resources.

An External Resource Zone (ERZ) will be created for each external Balancing Authority that has External Resources qualifying as Planning Resources, excluding those Balancing Authorities with only Coordinating Owner resources that are qualified to obtain local credit and/or Border External Resources.

Establishment of SRRZs, SRECs and SRICs

The Transmission Provider will establish and publish, on the Transmission Provider's public website, SRRZs, SRECs and SRICs for each Season as soon as practical but no later than the first business day of March for the following Planning Year. To calculate the SRECs and SRICs, the Transmission Provider will determine the transfer limit between SRRZs in accordance with applicable seams agreements, coordination agreements, or transmission service agreements. Next, the Transmission Provider will then complete a feasibility analysis in accordance with the Resource Adequacy Business Practices Manual to review operational events from each Coincident Peak Demand hour during the previous Planning Year, and forecasted expected conditions for each Season in the upcoming Planning Year, to determine if a further reduction to the transfer limit is warranted for reliability. If such a reduction is necessary, the Transmission Provider will reduce the regional directional transfer limit, as appropriate. The Transmission Provider will then subtract the sum of Firm Transmission Service Reservations on the MISO OASIS that utilize the contract path between SRRZs and are exporting from or wheeling through the Transmission Provider's Balancing Authority for the applicable Season in the Planning Year. This difference determines the SREC and SRIC to be utilized for the applicable Season in the Planning Year.

Prior to publishing the SRRZs, SRECs, and SRICs on its public website, Transmission Provider will present the feasibility analysis and resulting SREC and SRIC calculation to stakeholders.

Establishment of CIL and CEL Limits

On or before November 1st of each year, the Transmission Provider will determine preliminary values for the CIL and CEL for each of the LRZs for each Season in the following Planning Year by considering factors, including but not limited to, the following elements: (1) existing and planned Transmission System and Planning Resource additions; (2) transmission import and export capability; and (3) applicable NERC contingencies. To determine the CIL and CEL for each LRZ, the Transmission Provider will use models which contain the physical location of Load and Planning Resources for each Season. Generator output will be assigned to LRZs or ERZs consistent with the PRA representation of Planning Resources. Constraints that are identified as a result of determining the CIL and/or the CEL for each LRZ will be considered in the development of the MISO Transmission Expansion Plan (MTEP) in accordance with Attachment FF.

CIL will be equal to the Zonal Import Ability plus firm capacity commitments to non-MISO load. CEL will be equal to the Zonal Export Ability minus firm capacity commitments to non-MISO load.

The CIL and CEL values for each Season for each LRZ will be updated if needed prior to the Planning Resource Auction, but no later than eight (8) Business Days before the last Business Day in March, due to changes to firm capacity commitments from MISO resources to neighboring regions prior to the Planning Resource Auction.

MISO will determine the CEL for each Season for each ERZ no later than eight (8) Business Days before the last Business Day in March as equal to the ZRC quantity of the External Resources registered to participate in the PRA.

Establishment of Local Reliability Requirement

By November 1st prior to a Planning Year, the Transmission Provider will establish a Local Reliability Requirement (LRR) metric for each LRZ to determine the quantity of Unforced Capacity needed for each Season, without consideration of the benefit of the LRZ's CIL. First, the LOLE analysis for the Planning Year will be conducted by either adding or removing capacity until the LOLE reaches 0.1 day per year for the LRZ. If the LOLE for the Planning Year is less than 0.1 day per year, a perfect negative unit with zero forced outage rate will be added until the LOLE reaches 0.1 day per year. If the LOLE for the Planning Year is greater than 0.1 day per year, proxy units based on a unit of typical size and forced outage rate will be added to the model until the LOLE reaches 0.1 day per year. If the LOLE for a Season is equal to or greater than 0.01 day per year for the LRZ, the LRR for that Season will be calculated based on this LOLE analysis. If the LOLE for any Season is less than 0.01 day per year for the LRZ, an additional LOLE analysis will be performed to determine the LRR for that Season by adding a perfect negative unit with zero forced outage rate to that season until the LOLE in that Season reaches 0.01 day per year for the LRZ.

The Transmission Provider will model the location of Load and Planning Resources based on their representation in the Planning Resource Auction to determine the LRR for each LRZ. The minimum amount of capacity above the Local Resource Zone Peak Demand in the LRZ required to meet the reliability criteria will be used to establish the LRR for each Season.

The per unit LRR in each LRZ initially will be established as the ratio of the LRR over the Local Resource Zone Peak Demand modeled in the LOLE study. An LRZ's LRR shall be calculated by multiplying the per unit LRR for the LRZ times the forecasted Local Resource Zone Peak

Demand for each Season as provided by LSEs or EDCs, or as developed by the Transmission Provider, pursuant to Section 69A.1.

Establishment of Local Clearing Requirement

The Local Clearing Requirement for each LRZ for each Season will be determined by subtracting Zonal Import Ability and controllable exports from the LRR, as set forth in the Resource Adequacy Business Practices Manual. Controllable exports are exports from MISO resources that have firm capacity commitments to non-MISO load and that may be committed and dispatched by the Transmission Provider during a declared Energy Emergency. The LCR values will be updated if needed prior to the Planning Resource Auction due to changes in controllable exports.

Establishing Planning Reserve Margin Requirements

a. The Transmission Provider will establish Planning Reserve Margin Requirements (PRMR) for each Season for an LSE's Load within any given LRZ. The Initial PRMR will be determined by multiplying the LSE's forecasted Coincident Peak Demand for each Season, including transmission losses, by (1 + Transmission Provider Region PRM).

b. The Transmission Provider will use the Transmission Provider Region PRM for the Initial PRMR calculation unless an alternate PRM is established by a State Regulatory Authority. In such event, the Transmission Provider will use the alternate PRM that a State Regulatory Authority has created for the geographic area in which the state has jurisdiction. The Transmission Provider will convert any State Regulatory Authority provided PRM to a comparable Unforced Capacity basis.

Calculation of Transmission Losses

a. The Transmission Provider shall calculate the LBA transmission loss percentages for each Season using the process described as follows:

1. The Transmission Provider's State Estimator calculates transmission losses (MW) as part of the solution output process every five (5) minutes.
2. The transmission losses (MW) are computed on all transmission lines and transformers by summing up real power at both ends for each transmission element (retaining the convention for flow direction) or as the difference in real power (without the sign convention for flow direction) for each State Estimator solution.
3. The individual transmission losses (MW) for each element are summed to a total transmission values for each Local Balancing Authorities (LBA) level.
4. These LBA transmission loss values are then integrated across each hour to calculate an hourly transmission loss value (MW) for each LBA.
5. The total transmission loss value (MW) for each LBA will be the hourly integrated transmission losses value (MW) for the hour of the Coincident Peak Demand from the calendar year two years prior to the upcoming Planning Year.
6. For the purposes of the Transmission Provider Region, the LBA transmission loss percentages are calculated as the total LBA transmission losses divided by the total LBA peak data at that MISO peak hour for each Season. For purposes of a Local Resource Zone, the LBA transmission loss percentages are calculated as the

total LBA transmission losses divided by the total LBA peak data at the LRZ peak hour for each Season.

b. The Local Balancing Authority (LBA) transmission loss percentage shall apply to the LSE's applicable LBA Coincident Peak Demand and Local Resource Zone Peak Demand forecast to determine the LSE transmission losses. Behind-the-Meter-Generation Resources that are interconnected to the Transmission System shall be treated like other Resources with respect to transmission losses. Behind-the-Meter-Generation Resources and Distributed Energy Aggregated Resources that are not interconnected to the Transmission System, Demand Resources, and Energy Efficiency Resources shall be adjusted to account for serving load without incurring transmission losses by grossing up the MW quantity of such resources by (1.0 + the appropriate LBA transmission loss percentage).

Marginal Reliability Impact (MRI) Curves

A. The following process will be used to determine the MRI Curves for the Transmission Provider Region for each Season of the upcoming Planning Year. The minimum PRM requirement for each Season established in the LOLE analysis, as described in Section 68A.2, will be the starting point. Then, for each Season, a perfect negative unit(s) with a capacity of at least 50MW and no more than 250MW, or perfect proxy unit(s) with a capacity of at least 50MW and no more than 250MW will be added to the model and the LOLE analysis will be performed. The capacity of both the perfect negative unit(s) and perfect proxy unit(s) will be of equal value. The change in EUE as a result of adding or removing capacity will be calculated. An additional unit(s) with the same capacity value will be added or removed in addition to the first increment or decrement and the LOLE analysis will be performed again. This process will be repeated until sufficient data is available to fit a curve that measures changes to EUE as MWs are added or removed from the minimum PRM requirement.

B. The First Planning Area MRI Curve is a smoothed representation of reliability changes as measured by EUE as more or less MWs are included in the LOLE analysis. The following process will be used to determine the MRI Curves for the First Planning Area for each Season in the Planning Year. Assignment of LOLE risk across the Seasons will be the same as described in Section 68A.2 for the Planning Reserve Margin analysis. A minimum PRM requirement for the First Planning Area for each Season will be established through additional LOLE analysis in which the First Planning Area and Second Planning Area each have the same reliability target established for the

Transmission Provider Region as the starting point. After establishing the starting point, the MW quantity associated with the minimum PRM requirement in the Second Planning Area will be fixed, and capacity in the First Planning Area will then be added or removed to calculate changes to EUE in the First Planning Area.

C. The Second Planning Area MRI curve is a smoothed representation of reliability changes as measured by EUE as more or less MWs are included in the LOLE analysis. The following process will be used to determine the MRI Curves for the Second Planning Area for each Season in the Planning Year. Assignment of LOLE risk across the Seasons will be the same as described in Section 68A.2 for the Planning Reserve Margin analysis. A minimum PRM requirement for the Second Planning Area for each Season will be established through additional LOLE analysis in which the First Planning Area and Second Planning Area each have the same reliability target established for the Transmission Provider Region as the starting point. After establishing the starting point, the MW quantity associated with the minimum PRM requirement in the First Planning Area will be fixed, and capacity in the Second Planning Area will then be added or removed to calculate changes to EUE in the Second Planning Area.

RAR Process

Once the Transmission Provider has established the PRM, LCR, LRR, preliminary Capacity Import Limits and Capacity Export Limits and published such values on the Transmission Provider's website, then LSEs shall provide forecasted Coincident Peak Demand and Local Resource Zone Peak Demand data for the Planning Year. For Retail Choice areas, the EDC shall provide, on behalf of LSEs within the EDC, forecasted Coincident Peak Demand and Local Resource Zone Peak Demand data for the Planning Year to be used by the Transmission Provider. The Transmission Provider will then calculate each LSE's Initial PRMR for each Season. LSEs will meet their RAR obligation by: (i) submitting a Fixed Resource Adequacy Plan; (ii) submitting ZRCs for an RBDC Opt Out; (iii) Self-Scheduling ZRCs; (iv) purchasing ZRCs through the Planning Resource Auction process; and/or (v) paying the Capacity Deficiency Charge to meet a portion of their PRMR. LSEs that submit an RBDC Opt Out may not use any of the other options to satisfy their Final PRMR. LSEs not submitting an RBDC Opt Out may use one or more of all other available options, or any combination of available options, to satisfy their Initial or Final PRMR. The Transmission Provider will enforce the LCRs, final Capacity Import Limits and Capacity Export Limits for each LRZ, and Capacity Export Limits for each ERZ in the Planning Resource Auction. An ACP will be determined through the PRA process for each LRZ and ERZ for each Season and the ACP will be used to credit ZRCs that clear in the auction and to debit LSEs for the volume of their PRMR that is procured through the auction. Market Participants that own Planning Resources used to create ZRCs which clear in the PRA (or are identified in either a submitted Fixed Resource Adequacy Plan or an RBDC Opt Out) must meet the applicable performance requirements as described in sections 69A.3.9 and

69A.5. The Transmission Provider shall provide states, upon request, with relevant resource adequacy information as available, subject to the data confidentiality provisions in Section 38.9 of the Tariff.

Load Serving Entity Responsibilities

a. LSEs shall provide Coincident Peak Demand (and also, if available, Local Resource Zone Peak Demand forecasts) forecasts as specified in Section 69A.1.1b and will also be responsible for meeting their Final PRMR for each LRZ where they serve Load by submitting Fixed Resource Adequacy Plans, by Self-Scheduling ZRCs, by purchasing ZRCs through the PRA process, by submitting ZRCs for an RBDC Opt Out and/or by paying the Capacity Deficiency Charge.

b. The Transmission Provider will use Coincident Peak Demand, Local Resource Zone Peak Demand, and Energy forecasts for each Season that are submitted by an EDC in combination with allocation procedures that are agreed to by the applicable LSEs. These procedures will allow the Transmission Provider to initially allocate appropriate portions of the total forecasted Coincident Peak Demand and Local Resource Zone Peak Demand to each LSE as applicable pursuant to 69A.1.2.1, and to re-assign ZRC-related charges caused by customer switching between suppliers to the appropriate LSE.

c. All LSEs shall report to the Transmission Provider, through the MECT, whether such LSE will meet their PRMR for each LRZ for each Season in which the LSE serves Load by: (i) submitting a Fixed Resource Adequacy Plan; (ii) Self-Scheduling ZRCs; (iii) purchasing ZRCs through the Planning Resource Auction process; (iv) submitting an RBDC Opt Out; and/or, (v) paying the Capacity Deficiency Charge.

Forecasted Demand Identification

a. The Demand forecasts required in Section 69A.1 shall include: (1) the Coincident Peak Demand within each LBA Area in the Transmission Provider Region for the upcoming Planning Year; (2) the monthly non-coincident peak Demand and net Energy for Load within each LBA Area, for the upcoming Planning Year and the following Planning Year; (3) the non-coincident peak Demand and net Energy for Load within each LBA Area, for each Season, for the eight Planning Years subsequent to the two for which monthly values are provided in (2); and (4) the available Local Resource Zone Peak Demand within each LBA Area in the Local Resource Zone for the upcoming Planning Year. All of these forecasts shall be submitted by November 1st prior to each Planning Year and shall be consistent with Good Utility Practice. Forecast providers shall use the MECT or other means described in the BPM for Resource Adequacy to submit the requisite information. Details regarding the items required in the Demand forecasts submittal are in the BPM for Resource Adequacy.

b. The supplied Coincident Peak Demand and Local Resource Zone Peak Demand forecasts shall include the Demand expected for the forecast time period (*e.g.* the Coincident Peak Demand hour) augmented to include the normal Demand from forecasted demand resources, whether registered or not registered with the Transmission Provider, including Demand from any retail demand side management programs and Demand behind a DEAR. Such forecasts shall include Demand that would have occurred but for the existence of Energy Efficiency Resources that have been in operation less than four (4) years. All submissions for such forecast values shall include distribution losses, but not transmission losses. The Transmission Provider will be responsible for the calculation of the applicable transmission losses for the forecasts provided and for annually publishing such values for each LBA on its website by October 1, as specified in Section 68A.8 and the BPM for Resource Adequacy.

c. In order to assist with the development of the Coincident Peak Demand and Local Resource Zone Peak Demand forecasts, the Transmission Provider will make available the historical monthly peak hours for each of the four months June through September, since 2005, or as available, for the Transmission Provider Region and for each Local Resource Zone. On or before March 1st of each year, the Transmission Provider will review a sampling of submitted Demand forecast methodologies and inputs to ensure accuracy and consistency, in accordance with the BPM for Resource Adequacy. If the Transmission Provider determines that the Demand forecast methodologies are inaccurate or inconsistent, the Transmission Provider shall work with the applicable LSEs to reconcile such issues. If reconciliation is not achieved, or if Local Resource Zone Peak Demand forecasts are not available, then the Transmission Provider will provide the required forecast values.

d. All Coincident Peak Demand and Local Resource Zone Peak Demand forecasts shall reflect a 50% probability that the Demand will not exceed the forecasted Demand for the relevant period.

e. Consistent with Section 69A.1.2.1, the EDC must provide both the Transmission Provider and the respective LSEs with each retail customer's peak load contribution ("PLC") in each Season, including transmission losses and PRM as determined by the Transmission Provider, in the EDC's service territory by December 15th. At least five (5) Business Days before January 15, LSEs must notify the EDC and the Transmission Provider if they disagree with the EDC calculated PLC value.

f. If an LSE knows it will gain a wholesale customer by the beginning of any Season in the next Planning Year, then that LSE may provide the Transmission Provider with the Coincident Peak Demand and the Local Resource Zone Peak Demand forecast for such acquired load by November 1. In all other cases, the existing Market Participant serving such wholesale customer shall provide the Transmission Provider by November 1st with the Market Participant's forecast of the wholesale customer's Coincident Peak Demand and Local Resource Zone Peak Demand.

Accounting for Total Demand Forecasts Given Wholesale and Retail Load Switching

a. On or before January 15th, an EDC must notify the Transmission Provider through the MECT of the Initial PRMR for the LSE's proportion of the EDC's forecast Demand that it expects to serve on the 1st day of each Season in the next Planning Year. The LSE that is the provider of last resort ("POLR") for the EDC area in question will have the obligation to procure capacity for the required PRMR for the remaining Demand (*i.e.*, the remaining Demand is the EDC's forecast Coincident Peak Demand minus the sum of the LSE's allocated portion of forecast Coincident Peak Demand, identified as described above, in the EDC's service territory). The Transmission Provider will notify the POLRs of any remaining Initial PRMR within five (5) Business Days after January 15th.

b. On or before January 15th, to account for wholesale customers that may switch LSEs during the next Planning Year, the PRMR will be met as follows: (1) if an LSE has responsibility to serve a wholesale load on the 1st day of any Season in of the next Planning Year, then such LSE shall have the obligation to procure the required PRMR for such load for such Season; (2) if no LSE has responsibility for serving a wholesale load on of the 1st day of any Season in of the next Planning Year, then the LSE with an obligation to serve such load on November 1 before the Planning Year, shall have the obligation to procure capacity for the required PRMR for each Season in the upcoming Planning Year for such load, provided that such LSE anticipates that the contract for wholesale load will be extended; or (3) if the LSE advises the Transmission Provider that the LSE will not serve the contract for wholesale load, then the customer for such wholesale load shall inform the Transmission Provider by January

30th of the name of the Market Participant that will be responsible for the PRMR obligation for such wholesale load.

Daily Assignment of Coincident Peak Demand Obligations

a. For those areas of service where an LSE's Coincident Peak Demand forecast is included in the Coincident Peak Demand forecast submission of an EDC, the EDC will determine and report each LSE's portion of such Demand to the Transmission Provider, using the default method set forth in Section 69A.1.2.1.

b. In a state that permits retail load switching, the Transmission Provider shall allocate resource capacity costs on a daily basis to LSEs by multiplying the Final PRMR associated with identified customers served by the LSE times the applicable zonal Auction Clearing Price less any zonal deliverability benefits plus any Local Clearing Requirement Charges for the Local Resource Zone where the load is located, consistent with Section 69A.1.2.1.

c. In states where wholesale load may switch, the Transmission Provider shall allocate costs on a daily basis to LSEs. The LSE that acquires wholesale load will be charged for such load based upon the Final PRMR for the wholesale load's forecast Coincident Peak Demand times the applicable zonal Auction Clearing Price less any zonal deliverability benefits plus any Local Clearing Requirement Charges for the Local Resource Zone where the wholesale load is located.

d. An LSE may challenge the EDC Demand forecast under the dispute resolution procedures pursuant to Section 12 or it may refer the dispute to the Commission for resolution.

Default Method

a. The method submitted by an EDC must describe in detail the procedures and data used to determine the assignment of the EDC's forecast Coincident Peak Demand to its retail customers, including those served by LSEs providing service within the EDC's area.

b. EDC will assign a peak load contribution ("PLC") value to each retail customer, based on the most recent PLC values derived for each Season from each retail customer's Demand at the time of the Transmission Provider's peak Demand during each Season (*i.e.*, the Prior Seasonal Retail Customer Coincident Peak ("PSRCCP")). Retail customer peak demands should be increased to reflect any load reductions achieved and for which capacity credits are earned, either through retail programs or participation in wholesale markets (*e.g.* LMRs). In the aggregate, the PLCs determined by the EDC must equal the Initial PRMR that is calculated from the forecast Coincident Peak Demand provided by the EDC for each Season. This equality is achieved by multiplying each retail customer's demand at the time of the Transmission Provider's peak Demand during each Season prior to the Planning Year by the same adjustment factor, as shown in the equation below:

$$\Sigma_i \text{ PLC}_i = \text{Initial PRMR}_{EDC}$$

$$\text{Factor} = \text{Initial PRMR}_{EDC} \div \Sigma_i \text{ PSRCCP}_i$$

In other words, for each EDC, the sum of the individual retail customer (*i.e.*, i) PLC values must equal the EDC’s Initial PRMR. In addition, a single value (“Factor”) is defined as the ratio of the Initial PRMR for any EDC divided by the sum of all of the PSRCCP values for each of the EDC’s retail customers. The EDC must use the same Factor in the following equation:

$$\text{PLC}_i = \text{Factor x PSRCCP}_i \quad \forall i$$

Thus, for each EDC it must also be true that the PLC for any individual retail customer shall be equal to the product of that customer's PSRCCP times the same Factor identified in the second equation above. For the purposes of these equations, the following mathematical symbols are used: (1) Σ equals sum; (2) $_i$ equals individual retail customer, as in PLC_i or $PSRCCP_i$; and (3) ∀i equals for all i, as in: for each member of the set of retail customers.

c. The PSRCCP shall be adjusted (upward) to reflect any demand that was reduced during the Coincident Peak for each Season hour through the effect of a Load Modifying Resource, or through the effect of an Energy Efficiency Resource during the first four (4) full Planning Years of the EE Resource's existence. The Transmission Provider will provide to the EDC the amount of measured (or estimated if final settlement data is forthcoming) load reduction that occurred as a result of an ARC or LSE deploying a DRR, LMR or EDR following a Setpoint Instruction, Scheduling Instruction or EDR Dispatch Instruction during the Transmission Provider's Coincident Peak Demand.

Load Switching

Beginning the first Calendar Day of each Season in the Planning Year, the EDC will be responsible for tracking the individual customer Final PRMR values transferred from the originally supplying LSE to the newly supplying LSE now responsible for resource adequacy commitments.

Forecasted Demand for FRP/FRS Agreements

Full Responsibility Purchases/Sales (FRP/FRS) agreements are treated effectively like a transfer of Demand and all RAR obligations from one LSE to another Market Participant. A purchaser under an FRP/FRS agreement shall submit the forecasted Coincident Peak Demand and Local Resource Zone Peak Demand associated with such agreement to the Transmission Provider through the MECT for the applicable Planning Year. A seller under an FRP/FRS agreement is contractually obligated to comply with all of the RAR obligations for the transferred Demand during the Planning Year encompassing the planned Coincident Peak Demand. The purchaser under an FRP/FRS agreement no longer has the RAR obligations for the transferred Demand; provided however, that if the seller under an FRP/FRS agreement is not an LSE under the jurisdiction of the Transmission Provider, then the purchaser under the FRP/FRS agreement will remain responsible for any RAR obligations associated with the Demand transferred under the FRP/FRS agreement. A seller under an FRP/FRS agreement will be responsible for the transferred Demand to meet this additional obligation like it was their own Demand. If a seller and a purchaser under an FRP/FRS agreement cannot agree on whether a particular transaction is an FRP/FRS agreement, then either party may invoke the dispute resolution procedures in Section 12 of the Tariff.

Multiple Region Planning Resources

If an LSE serves Demand both in the Transmission Provider Region and outside the Transmission Provider Region, then the LSE must separately satisfy its Final PRMR in all areas of the Transmission Provider Region. Compliance with RAR shall not affect an LSE's obligation to maintain distinct and separate amounts of resources to cover its applicable planning reserve obligation for the amount of Demand outside the Transmission Provider Region.

Capacity Tracking Tool

To facilitate RAR, the Transmission Provider shall administer the MECT, a title tracking and registration tool that shall include the ability to enable Market Participants and LSEs to meet their RAR responsibilities.

Planning Resource Requirements

Nothing herein shall infringe upon the requirement that LSEs comply with applicable state safety standards, planning reserve margins, or be subject to the enforcement thereof. If the Transmission Provider becomes aware that any Planning Resource fails to meet the requirements of this section, then the Transmission Provider shall promptly notify the Market Participant and specify the reasons for any such failure. Wherever possible, the Transmission Provider and the Market Participant will work in good faith to remedy deficiencies, if any, in meeting the Planning Resource requirements, through informal communications rather than Commission filings.

Capacity Resources

As described below, a Generation Resource, External Resource, Demand Response Resource - Type II, Intermittent Generation, Dispatchable Intermittent Resource, Electric Storage Resource, or Hybrid Resource is eligible to become a Capacity Resource. The Transmission Provider will qualify a Capacity Resource for any applicable Season in the upcoming Planning Year, in accordance with processes specified in the BPM for Resource Adequacy. Electric Storage Resources can be Capacity Resources if they meet all the requirements as specified in the BPM for Resource Adequacy, including the requirement to be able to continuously discharge for a minimum set of four (4) consecutive operating Hours across the Transmission Provider's coincident peak for each day, in accordance with the BPM for Resource Adequacy, provided that an Electric Storage Resource may de-rate its capacity in order to comply with this requirement.

Generation Resources that are not Dispatchable Intermittent Resources or Distributed Energy Aggregated Resources

1. Generation Resources and Electric Storage Resources that are not Dispatchable Intermittent Resources or Distributed Energy Aggregated Resources are eligible to qualify as Capacity Resources by a Market Participant that possesses ownership or equivalent contractual rights for the Resource by:

   (a) registering such resource with the Transmission Provider as documented in the BPM for Market Registration;

   (b) demonstrating GVTC capability for each Season in the Planning Year as established in the BPM for Resource Adequacy;

   (c) submitting generator availability data (including, but not limited to, NERC Generation Availability Data System (GADS) information) into a database provided by the Transmission Provider and as established in the BPM for Resource Adequacy;

   (d) by submitting the GVTC results to the Transmission Provider no later than October 31 prior to such Planning Year for existing Capacity Resources unless the Transmission Provider has granted an extension pursuant to Section 69A.3.1.a.4; and

   (e) demonstrating deliverability as described in Section 69A.3.1(g). All new Generation Resources and Electric Storage Resources that are not Dispatchable Intermittent Resources and Distributed Energy Aggregated Resources, or an existing Generation Resource and Electric Storage Resource that is not a Dispatchable Intermittent Resource and s Distributed Energy Aggregated Resource that has an increased installed capacity, shall submit their GVTC to the Transmission Provider prior to qualification, but no later than March 1 prior to the PRA, as established in the BPM for Resource Adequacy.

2. Installed Capacity (ICAP) Deferral

If a Market Participant for a Generation Resource and Electric Storage Resource that is not a Dispatchable Intermittent Resource (including a Generation Resource and Electric Storage Resource that has the status of Suspend pursuant to Section 38.2.7) and a Distributed Energy Aggregated Resource that has not completed GVTC testing by the deadlines provided in 69A.3.1.a.1, is not expected to demonstrate deliverability, or is otherwise not expected to demonstrate commercial operation prior to March 1, ZRCs from such capacity may be used in the PRA or in a FRAP (including through bilateral ZRC transactions), subject to the notification, credit, and non-compliance provisions of Section 69A.7.9.

3. Reporting generator availability data based on GVTC is not required for a Generation Resource or Electric Storage Resource that is not a Dispatchable Intermittent Resource and a Distributed Energy Aggregated Resource and that is less than 10 MW if the Market Participant has never provided such data for such Resource. A Market Participant that begins reporting generator availability data based on GVTC for a Generation Resource or Electric Storage Resource that is not a Dispatchable Intermittent Resource and that is less than 10 MW must continue to report such data. A Generation Resource or Electric Storage Resource that has provisional Interconnection Service does not qualify as a Capacity Resource.

4. A Market Participant for a Generation Resource required to submit GVTC results must use Reasonable Efforts to submit GVTC by October 31 prior to the upcoming Planning

Year. If circumstances prevent the Market Participant from submitting the GVTC results for the Generation Resource by October 31, the Market Participant must notify the Transmission Provider no later than five (5) Business Days after October 31 and request an extension. The extension request must include a reasonable explanation and justification for missing the deadline and an expected completion date prior to the upcoming Planning Year. The Transmission Provider will review each extension request on a case by case basis to determine whether or not to approve or deny the request to extend the GVTC deadline. Denial of an extension will not preclude the Market Participant for the Generation Resource from utilizing the ICAP Deferral process as described in Section 69A.7.9.

Demand Response Resources – Type II

1. Demand Response Resources – Type II backed by a Demand Resource are eligible to qualify as Capacity Resources. A Market Participant that possesses ownership or equivalent contractual rights in the DRR – Type II can register such resource as a Capacity Resource with the Transmission Provider for the upcoming Planning Year as documented in the BPM for Market Registration and by meeting the following requirements:
    a. For an existing DRR – Type II that is a Capacity Resource, the Market Participant shall demonstrate capability and availability to reduce Demand in response to instructions from the Transmission Provider for each applicable Season and shall submit such data to the Transmission Provider no later than October 31 prior to such Planning Year unless the Transmission Provider has granted an extension, as established in the BPM for Resource Adequacy.
    b. For a new DRR – Type II or for an existing DRR – Type II that has experienced an increase in its Capacity Rating, and that is backed by a Demand Resource, the Market Participant shall submit test data to the Transmission Provider prior to qualification, but no later than March 1 prior to the PRA, as established in the BPM for Resource Adequacy.
2. A Demand Response Resource – Type II that is backed by behind the meter generation is eligible to qualify as Capacity Resources. A Market Participant that possesses ownership or equivalent contractual rights in the DRR – Type II can register such resource as a Capacity Resource with the Transmission Provider for the upcoming Planning Year as

documented in the BPM for Market Registration and by meeting the following requirements:

a. A Market Participant shall demonstrate GVTC capability of the DRR – Type II backed by behind the meter generation for each Season in the Planning Year as established in the BPM for Resource Adequacy;
b. An existing DRR – Type II backed by behind the meter generation shall submit GVTC results to the Transmission Provider no later than October 31 prior to such Planning Year unless the Transmission Provider has granted an extension pursuant to Section 69A.3.1.b.4; and
c. A Market Participant shall submit generator availability data (including, but not limited to, NERC Generation Availability Data System information) for the DRR – Type II backed by behind the meter generation into a database provided by the Transmission Provider.
d. For a new DRR – Type II or an existing DRR – Type II that has an increased installed capacity, and that is backed by behind the meter generation, the Market Participant shall submit GVTC data to the Transmission Provider prior to qualification, but no later than March 1 prior to the PRA, as established in the BPM for Resource Adequacy.

3. Installed Capacity (ICAP) Deferral

If a Market Participant for a DRR – Type II has not completed GVTC testing by the deadlines provided in 69A.3.1.b.2, is not expected to demonstrate deliverability, or is otherwise not expected to demonstrate commercial operation prior to March 1, ZRCs from such capacity may be used in the PRA, in a FRAP (including through bilateral ZRC transactions), or in an RBDC Opt Out (including through bilateral ZRC transactions) subject to the notification, credit, and non-compliance provisions of Section 69A.7.9.

4. Reporting generator availability data based on GVTC is not required for a DRR – Type II backed by behind the meter generation facility of less than 10 MW if the Market Participant has never provided such data for such behind the meter generation facility. A Market Participant that begins reporting generator availability data for behind the meter generation facility that is less than 10 MW based on GVTC must continue to report such data. A Demand Response Resource – Type II that has provisional Interconnection Service does not qualify as a Capacity Resource. In accordance with the qualification provisions in the BPM for Resource Adequacy, the Transmission Provider will qualify a Demand Response Resource – Type II for the applicable Season in the upcoming Planning Year.
5. A Market Participant for a DRR – Type II required to submit GVTC results must use Reasonable Efforts to submit GVTC by October 31 prior to the upcoming Planning Year. If circumstances prevent the Market Participant from submitting the GVTC results for the DRR by October 31, the Market Participant must notify the Transmission Provider no later than five (5) Business Days after October 31 and request an extension. The extension request must include a reasonable explanation and justification for missing the deadline and an expected completion date prior to the upcoming Planning Year. The Transmission Provider will review each extension request on a case by case basis to determine whether or not to approve or deny the request to extend the GVTC deadline.

Denial of an extension will not preclude the Market Participant for the DRR – Type II from utilizing the ICAP Deferral process as described in Section 69A.7.9.

External Resources:

1. External Resources, including those specified in Diversity Contracts and PPAs (which are subject to additional qualification requirements in section 69A.3.1.c.4), are eligible to qualify as Capacity Resources by a Market Participant that possesses ownership or equivalent contractual rights in External Resources by: (a) registering such resources with the Transmission Provider as documented in the BPM for Resource Adequacy; (b) demonstrating GVTC capability for each Season that the resource will be registered in as established in the BPM for Resource Adequacy by providing operational data, and by submitting the GVTC results to the Transmission Provider no later than October 31 prior to such Planning Year for existing Capacity Resources unless the Transmission Provider has granted an extension pursuant to Section 69A.3.1.c.5; (c) submitting generator availability data (including, but not limited to, NERC Generation Availability Data System information) into a database provided by the Transmission Provider and as established in the BPM for Resource Adequacy; (d) identifying one or more specific External Resource(s) that can be verified by the Transmission Provider as Capacity Resource(s) and which does not include any portion(s) of an External Resource that has already qualified as a Capacity Resource; (e) demonstrating that there is firm transmission service for each Season that the resource is to be registered in from the External Resource to the border interface CPNode of the Transmission Provider Region and either that firm Transmission Service has been obtained to deliver capacity on the Transmission System from the border to a Load within an LRZ or demonstrating deliverability as described in Section 69A.3.1.g; and (f) certifying that any External

Resources being identified are not otherwise being used as capacity resources in any other RTO/ISO, in another resource adequacy construct, or in an external balancing authority's resource plan for its firm end-use load and capacity sales requirements within the external balancing authority area.

2. Installed Capacity (ICAP) Deferral

   If a Market Participant for an External Resource has not completed GVTC testing by the deadlines provided in 69A.3.1.c.1, is not expected to demonstrate deliverability, or is otherwise not expected to demonstrate commercial operation prior to March 1, ZRCs from such capacity may be used in the PRA, in a FRAP (including through bilateral ZRC transactions), or in an RBDC Opt Out (including through bilateral ZRC transactions) subject to the notification, credit, and non-compliance provisions of Section 69A.7.9.

3. Reporting generator availability data for an External Resource of less than 10 MW based upon GVTC is not required if the Market Participant has never provided such data for such External Resource. A Market Participant that begins reporting generator availability data for an External Resource that is less than 10 MW based on GVTC must continue to report such data. All new External Resources or an existing External Resource that has an increased installed capacity shall submit their GVTC to the Transmission Provider prior to qualification as established in the BPM for Resource Adequacy. In accordance with the qualification provisions in the BPM for Resource Adequacy, the Transmission Provider will qualify an External Resource for the applicable Season in the upcoming Planning Year.

4. In the case of a power purchase agreement (PPA), including, but not limited to a Diversity Contract, then the agreement shall meet the additional qualification requirements set forth below:

   i. A PPA that does not identify the full Installed Capacity of the External Resource from which power will be supplied must specify the portions of each such External Resource that is available under the PPA (i.e. slice-of-system resources) and that are verifiable by the Transmission Provider. Each External Resource specified in such PPA must meet the criteria for a Capacity Resource for all of the portion of the contract amount assigned to the External Resource(s). The capacity from the External Resource will be reduced proportionately to remove amounts that fail to meet such criteria.

   ii. A copy of every PPA must be provided by the Market Participant using External Resources from such PPA as a Capacity Resource to the Transmission Provider to enable it to verify the External Resource(s) that are backing the PPA and to confirm compliance with RAR. Any redacted versions of a PPA submitted by a Market Participant must contain sufficient information to allow the Transmission Provider to verify compliance with RAR. The Transmission Provider will maintain the confidentiality of these agreements in accordance with the confidentiality provisions in Section 38.9 of the Tariff.

   iii. For PPAs executed after April 3, 2014, one of the following must apply regarding the external balancing authority in which the External Resource is located:

(a) In the case of unit specific sales, if the MISO Balancing Authority Area is experiencing an Energy Emergency, the external balancing authority will not interrupt the PPA Schedule from the External Resource unless the generator being used to serve the unit specific sale has a forced outage.

(b) In the case of slice-of-system sales, if the external balancing authority area experiences an Energy Emergency and the MISO Balancing Authority Area is simultaneously experiencing an Energy Emergency, the external balancing authority will only interrupt the PPA Schedule on a pro rata basis with the shedding of firm end-use load in the external balancing authority area. Pro rata interruption of the PPA Schedule from the External Resource will be determined as the ratio of the PPA Schedule to the sum of the external balancing authority firm end-use load plus the PPA Schedule. (c) If the external balancing authority (1) is located within the Transmission Provider's reliability coordinator area; (2) participates in a contingency reserve sharing group with the Transmission Provider; and (3) has a Seams Operating Agreement with the Transmission Provider containing the following features, then in the event that the external balancing authority area experiences an Energy Emergency and the MISO Balancing Authority Area is simultaneously experiencing an Energy Emergency, the Transmission Provider and the external balancing authority will share interruption of PPA Schedules from an External Resource and load shedding in the external balancing authority area on a pro rata basis in proportion to the end-use load in the area under the Energy Emergency. Pro rata sharing shall be determined as the respective ratio of each of the balancing authority's end-use load in the Energy Emergency Area divided by the sum of the end-use load of each balancing authority in the Energy Emergency Area. The Seams Operating Agreement must (1) ensure that the external balancing authority has established a planning reserve margin and qualifications for planning resources using processes and criteria comparable to the Transmission Provider; (2) specify the actions that will be taken by both entities during an Energy Emergency prior to implementing firm end-use load shedding, and (3) specify that the external balancing authority will submit end-use load estimates to the Transmission Provider in a comparable manner as submitted by Load entities in Module E-1, provide generator GVTC and GADS data for all resources used to serve firm requirements of the external balancing authority, and provide transparency in the form of submittal of fixed resource plans comparable to processes used by Market Participants for Fixed Resource Adequacy Plans in the Transmission Provider's Module E-1.

iv. A PPA executed prior to April 3, 2014 will continue to qualify as a Planning Resource for the full term of the PPA if it is only interruptible as a last resort under Requirement 2 of NERC Standard EOP-011-1. A Diversity Contract executed prior to April 3, 2014 will continue to qualify as a Planning Resource, if it is only interruptible as a last resort under Requirement 2 of the NERC Standard EOP-011-1 between June 1st and September 30th.

v. A Market Participant may only qualify a PPA as a Capacity Resource if such agreement establishes a firm obligation on the part of the seller of the Capacity to deliver the Capacity to the Market Participant.

vi. If the terms and conditions in a PPA do not explicitly conform with every requirement of Section 69A.3.1.c. 4 (i) through (iv) above, the Transmission Provider will use alternative documentation and verification procedures to determine if the PPA qualifies as a Capacity Resource. A party seeking Capacity Resource status for a non-conforming PPA must provide the Transmission Provider with written information regarding whether: (a) the PPA was executed prior to October 20, 2008; (b) an RE has accredited the PPA to satisfy resource adequacy requirement provisions; (c) the PPA has provided reliable capacity to the Transmission Provider Region; (d) the supplier(s) of capacity in the PPA commit(s) to provide the capacity to an LSE in the Transmission Provider Region in a defined amount at a defined location based upon the supplier(s)' portfolio of generation assets; (e) energy from the PPA cannot be interrupted for economic reasons and will only be interrupted for force majeure type conditions as a last resort during Emergency conditions; (f) either the purchaser(s) or the supplier(s) of capacity in the PPA has committed to offer energy into the Day-Ahead Energy and Operating Reserves Market and all pre-Day-Ahead and the first post Day-Ahead Reliability Assessment Commitment processes for all periods for which energy is available under the PPA, consistent with the must offer provisions in Section 69A.5; (g) the physical resource(s) backing the PPA are identified by the supplier of the PPA; (h) the portion of the physical resources backing the PPA has not otherwise been registered by any other entity as Capacity Resources in the Transmission Provider Region or as capacity resources in any other region; and (i) if the PPA is renewed, the PPA will be modified to comply with the terms of section 69A.3.1.c. 4 (i) through (iv) and (vi). The Transmission Provider will analyze all available alternative documentation and verification information. Based upon such analysis, the Transmission Provider will inform the party seeking Capacity Resource status for the PPA within 30 days whether the PPA qualifies as a Capacity Resource.

vii. No PPA may be qualified as a Capacity Resource if such agreement includes provisions permitting the seller to interrupt deliveries thereunder for reasons other than Force Majeure.

5. A Market Participant for an External Resource required to submit GVTC results must use Reasonable Efforts to submit GVTC by October 31 prior to the upcoming Planning Year. If circumstances prevent the Market Participant from submitting the GVTC results for the External Resource by October 31, the Market Participant must notify the Transmission Provider no later than five (5) Business Days after October 31 and request an extension. The extension request must include a reasonable explanation and justification for missing the deadline and an expected completion date prior to the upcoming Planning Year. The Transmission Provider will review each extension request on a case by case basis to determine whether or not to approve or deny the request to extend the GVTC deadline.

Denial of an extension will not preclude the Market Participant for the External Resource from utilizing the ICAP Deferral process as described in Section 69A.7.9.

6. Existing Resources that modify their registration, scheduling and market participation in the Energy and Operating Reserves Markets and become pseudo-tied External Resources after September 1, 2022 will be accredited at the lesser of class average SAC in Schedule 53 or the accreditation provisions governing External Resources in section 69A.4.1.b.

Use Limited Resources

The Market Participant shall identify eligible Generation Resources, Electric Storage Resources, Distributed Energy Aggregated Resources or External Resources to the Transmission Provider that are Use Limited Resources. The Market Participant that seeks to qualify a Generation Resource, Distributed Energy Aggregated Resource or External Resource as a Use Limited Resource under RAR shall meet all the requirements as specified in the BPM for Resource Adequacy. A Use Limited Resource must be able to operate for a minimum set of four (4) consecutive operating Hours across the Transmission Provider's coincident peak for each day in each applicable Season in order to qualify as a Capacity Resource, in accordance with the BPM for Resource Adequacy.

Intermittent Generation, Dispatchable Intermittent Resources, and Distributed Energy Aggregated Resources

Intermittent Generation, Dispatchable Intermittent Resources, and Distributed Energy Aggregated Resources are resources that are eligible to qualify as a Capacity Resource by a Market Participant provided that the Market Participant: (a) possesses ownership or equivalent contractual rights for the resource; (b) supplies historical performance data or required documentation for the resource as established in the BPM for Resource Adequacy; and (c) registers the resource with the Transmission Provider in accordance with the BPM for Market Registration (if the resource is located within the MISO Balancing Authority Area metered boundary), or the BPM for Resource Adequacy (if the resource is located outside the MISO Balancing Authority Area metered boundary).

Curtailments

At its sole discretion, the Transmission Provider may curtail exports not being used as capacity by an external balancing authority and/or recall External Resources, PPAs, and Diversity Contracts sourced from a Capacity Resource during a declared Energy Emergency. Procedures for such actions shall be specified in the operating procedures. With respect to external balancing authorities that have a Seams Operating Agreement with the Transmission Provider pursuant to Section 69 A.3.1.c.4, during a declared Energy Emergency in the MISO Balancing Authority Area, the Transmission Provider shall only interrupt or reduce Export Schedules associated with a sale of capacity on a reciprocal pro rata basis to that required of the external balancing authority in Section 69A.3.1.c.4.(iii).

A. Determination of Deliverability of Generation Resources, Electric Storage Resources, and External Resources:

The Transmission Provider shall be responsible for determining whether Generation Resources, Electric Storage Resources, and External Resources eligible to be Capacity Resources are deliverable to Load. The deliverable amount of such Generation Resources, Electric Storage Resources, and External Resources will be any combination of the following:

i. The amount of Network Resource Interconnection Service under Attachment X;

ii. The amount of Energy Resource Interconnection Service under Attachment X that is coupled with firm Transmission Service;

iii. The amount of firm Transmission Service associated with a Grandfathered Agreement that can only be used to satisfy PRMR within the LRZ of the Load under the Grandfathered Agreement;

iv. The amount of aggregate deliverability that a Generation Resource or External Resource was granted through the market transition deliverability test by the Transmission Provider and could qualify for Network Resource Interconnection Service; or

v. The amount of non-aggregate deliverability that a Generation Resource or External Resource was granted by the transmission provider and confirmed by a Network Customer as a designated Network Resource under the OASIS reservation process in place prior to either the initial effective date of the Energy Market in 2005 or that corresponding Transmission Owner's integration date, will be accepted by the Transmission Provider as deliverable to the Network Loads of the Network Customer for that term of the confirmed designation, as such term may be extended.

B. Determination of Deliverability of Intermittent Generation, Dispatchable Intermittent Resources, and Electric Storage Resources:

The Transmission Provider shall be responsible for determining whether Intermittent Generation, Dispatchable Intermittent Resources, and Electric Storage Resources eligible to be Capacity Resources are deliverable to Load. The deliverable amount of such Intermittent Generation, Dispatchable Intermittent Resources, and Electric Storage Resources will be any combination of the following:

i. The amount of Network Resource Interconnection Service under Attachment X;

ii. The amount of Energy Resource Interconnection Service under Attachment X that is coupled with firm Transmission Service;

iii. The amount of firm Transmission Service associated with a Grandfathered Agreement that can only be used to satisfy PRMR within the LRZ of the Load under the Grandfathered Agreement;

iv. The amount of aggregate deliverability that the Intermittent Generation or Dispatchable Intermittent Resource was granted through the market transition deliverability test by the Transmission Provider and could qualify for Network Resource Interconnection Service; or,

v. The amount of non-aggregate deliverability that a Intermittent Generation or Dispatchable Intermittent Resource was granted by the transmission provider and confirmed by a Network Customer as a designated Network Resource under the

OASIS reservation process in place prior to either the initial effective date of the Energy Market in 2005 or that corresponding Transmission Owner's integration date, will be accepted by the Transmission Provider as deliverable to the Network Loads of the Network Customer for that term of the confirmed designation, as such term may be extended.

C. Determination of Deliverability of Distributed Energy Aggregated Resources

The Transmission Provider shall be responsible for determining whether Distributed Energy Aggregated Resources eligible to be Capacity Resources are deliverable to Load. The Distributed Energy Resource Aggregator will coordinate with the Electric Distribution Company in order for the Electric Distribution Company to perform a technical review of the Distributed Energy Aggregated Resource's transmission system impacts. Any MW found to be injecting onto the transmission system as a result of the technical review must demonstrate deliverability by obtaining External Network Resource Interconnection Service or firm Transmission Service in order to qualify for the Planning Resource Auction or a FRAP.

Retirement, Suspension, Installed Capacity (ICAP) Deferral and Replacement of Planning Resources

a. Retirement, Suspension, ICAP Deferral and Replacement

A Planning Resource for which a Market Participant requests a change in status in accordance with the System Support Resource (SSR) provisions described in Section 38.2.7 will no longer qualify as a Planning Resource effective as of the actual date that the status of the Planning Resource changes to Retire pursuant to Section 38.2.7. A Generation Resource that has the status of Suspend pursuant to Section 38.2.7 will continue to qualify as a Planning Resource in accordance with the BPM for Resource Adequacy. A Planning Resource for which a Market Participant submits an ICAP Deferral Notice will be subject to ICAP Deferral Requirements and Charges pursuant to Section 69A.7.9. As used in this section, “cleared ZRCs” include ZRCs that cleared in the PRA, were used in a FRAP, were used in an RBDC Opt Out, or were used to replace ZRCs in accordance with this section. As used in this section, “uncleared ZRCs” include ZRCs that did not clear in the PRA, were not used in a FRAP, were not used in an RBDC Opt Out or were not used to replace ZRCs in accordance with this section. If a Planning Resource for which a Market Participant converts Seasonal Accredited Capacity into ZRCs is Retired or Suspended prior to the end of the Season during the Planning Year in which the ZRCs cleared, such Market Participant must replace the cleared ZRCs with uncleared ZRCs. If a Market Participant does not replace such ZRCs associated with a Retired or Suspended Planning Resource, a Capacity Replacement Non-Compliance Charge will be assessed as determined below in this Section. If a Market Participant’s Planning Resource fails to satisfy the ICAP deferral requirements set forth in Section 69A.7.9 and the Market Participant does not replace cleared ZRCs with uncleared ZRCs, an ICAP Deferral Non-Compliance Charge will be assessed pursuant to Section 69A.7.9. If a Planning Resource for which a Market Participant converts Seasonal Accredited Capacity into ZRCs is unable to meet the applicable performance requirements for the cleared ZRCs as described in Section 69A.5 for greater than thirty-one (31) Days in total due to full or partial Generator Planned Outage during the Season of the Planning Year in which the ZRCs cleared, or for Planning Resources that are subject to Diversity Contracts for greater than one (1) Month during any Season of the Planning Year in which the ZRCs cleared, such Market Participant must replace the cleared ZRCs with uncleared ZRCs to transfer the performance requirements applicable to the Planning Resource. If a Market Participant does not replace such ZRCs associated with a Planning Resource, a Capacity Replacement Non-Compliance Charge will be assessed as determined below in this Section. A Planning Resource for which a Market Participant converts Seasonal Accredited Capacity into ZRCs that are used to replace cleared ZRCs must meet the applicable performance requirements as described in sections 69A.3.3.1 and 69A.5 for the balance of the Season of the Planning Year, subject to the same replacement requirements set forth above. Any combination of cleared or replaced ZRCs that are on full or partial Generator Planned Outage for greater than thirty-one (31) Days in total during a Season, or for any other reason including full or partial Generation Outages that were not planned but were known or could have been reasonably anticipated at the time of the PRA, as set forth in the Market Monitoring and Mitigation Business Practices Manual, or unavailable because subject to a Diversity Contract that is not available for greater than one (1) Month during a Season, will be assessed a Capacity Replacement Non-Compliance Charge. If a Planning Resource for which a Market Participant converts Seasonal Accredited

Capacity into ZRCs is unable to meet the applicable performance requirements for the cleared ZRCs as described in Sections 69A.3.3.1 and 69A.5 due to a Catastrophic Generator Outage any time during the Season(s) of the Planning Year in which the ZRCs cleared such Market Participant may replace the cleared ZRCs with uncleared ZRCs to transfer the performance requirements applicable to the Planning Resource. A Planning Resource may not transfer its performance requirements by replacing the cleared ZRCs with uncleared ZRCs other than in the case of suspension, retirement, ICAP deferral, Catastrophic Generator Outage or full or partial Generator Planned Outages that may exceed thirty-one (31) Days in the Season as discussed immediately above. Cleared ZRCs can be replaced with uncleared ZRCs that are not from the same LRZ or ERZ by examining post-replacement clearing as if it were the PRA clearing results, so that such replacement: (1) does not violate any CIL used in the PRA; (2) does not violate any CEL used in the PRA; (3) does not reduce the remaining total ZRCs for any LRZ of cleared ZRCs below the LCR for that LRZ; and (4) does not exceed any intra-regional flow ranges established under applicable seams agreements, coordination agreements, or transmission service agreements. ZRC replacements from LRZs or ERZs other than that of the cleared ZRCs will be processed in accordance with the following parameters:

i. ZRC replacement shall be processed on a first come, first served basis.

ii. The amount of cleared ZRCs in each LRZ or ERZs at the time of a ZRC replacement shall be based upon the current amounts of cleared ZRCs, including any previous replacement transactions.

ZRC replacement shall have no impact on settlements from the PRA, FRAPs, and RBDC Opt Out, including any assessed Capacity Replacement Non-Compliance Charges.

b. Capacity Replacement Non-Compliance Charge and Distribution

i. Capacity Replacement Non-Compliance Charges will be calculated as follows: the number of days for which the Market Participant had a replacement requirement but failed to replace per section 69A.3.1.h.a above multiplied by the amount of ZRCs that failed to be replaced multiplied by the sum of the ACP for the applicable Season and the daily CONE value (1/365 times CONE). The ACP and the CONE values will be based on the LRZ where the Planning Resource cleared those ZRCs. If the Planning Resource is represented in an ERZ connected to a single SRRZ, the applicable CONE value will be the greatest CONE value of all LRZs in the respective SRRZ. For External Resources represented in ERZs that are connected to multiple SRRZs or that are not connected to any SRRZs, the applicable CONE value will be the greatest CONE value of all LRZs in those connected SRRZs.

ii. Distribution of Capacity Replacement Non-Compliance Charges: Capacity Replacement Non-Compliance Charge revenues received by the Transmission Provider will be distributed to Market Participants representing LSEs that have met their Final PRMR during the applicable Season of the Planning Year on a *pro rata* basis, based upon their respective LSEs' share of Final PRMR for the Transmission Provider Region.

Energy Efficiency Resources (EE Resource)

An Energy Efficiency Resource is a Planning Resource, in which the Market Participant possesses ownership or equivalent contractual rights, from an end-use customer project (including the installation of more efficient devices or equipment or implementation of more efficient processes or systems) that was implemented after July 20, 2011, exceeding then-current building codes, appliance standards, or other relevant standards, designed to achieve a continuous reduction in electric energy consumption during On Peak daylight hours, as further described in the BPM for Resource Adequacy. EE Resources are eligible to qualify as Planning Resources by registering such EE Resources as Planning Resources with the Transmission Provider, as documented in the BPM for Resource Adequacy. An EE Resource can qualify as a Planning Resource for ZRCs for each Season for up to four (4) Planning Years immediately following the EE Resource's initial qualification provided that the energy efficiency measures are fully implemented prior to each Planning Year. ZRCs from EE Resources will be grossed-up by the amount of avoided transmission losses in accordance with Section 68A.8.b and also by the applicable PRM in accordance with Section 68A.2. EE Resources shall not require notice, dispatch, or operator intervention, such that the EE Resource will reduce the total amount of electrical energy needed, while delivering a comparable or improved level of end-use service, in accordance with the BPM for Resource Adequacy. The additional requirements for EE Resource measurement and verification are found in Attachment UU.

Demand Response Resources – Type I and Load Modifying Resources

Demand Response Resources – Type I and Load Modifying Resources can be offered as ZRCs in the PRA or can be used in FRAPs pursuant to Section 69A.9 or used in an RBDC Opt Out pursuant to Section 69A.9.1. As described below, a Demand Resource or behind the meter generation is eligible to qualify as a DRR – Type I or a Load Modifying Resource if it meets the following requirements. All DRR – Type I and LMRs that are cleared in the PRA or were submitted in a FRAP for a Season or submitted in an RBDC Opt Out must be available for use in the event of an Emergency as declared by the Transmission Provider, pursuant to the Emergency Operating Procedures of the Transmission Provider, unless replaced with other ZRCs pursuant to Section 69A.3.1.h. In accordance with the BPM for Resource Adequacy, the Transmission Provider will qualify a DRR – Type I or LMR for the applicable Season in the upcoming Planning Year. The Seasonal Accredited Capacity for DRR – Type Is and LMRs will be calculated pursuant to Schedule 53B.

Deployment Procedures for LMR

Procedures for deployment of LMR are found in the BPM for Resource Adequacy and emergency operating procedures. Such procedures shall be consistent with the information provided by the Market Participant regarding availability and notice time. At a minimum the Market Participant will provide the deployment parameters of the LMR (as described in Sections 69A.3.5 and 69A.3.6), during declared Emergencies prior to the use of Operating Reserves to achieve energy balance. The Market Participant shall, at all times, notify the Transmission Provider or Local Balancing Authority when the status or availability of an LMR changes, except for de minimis changes that do not need to be reported, according to procedures specified in the BPM for Resource Adequacy and emergency operating procedures. The Transmission Provider or Local Balancing Authority shall coordinate with the Market Participant that owns or controls such LMR when necessary to deploy or notify such LMR of a planned deployment. The Transmission Provider or Local Balancing Authority shall coordinate with the Market Participant that owns or controls such LMR when necessary to notify such LMR of a planned deployment through the issuance of Scheduling Instructions. Market Participants may be issued Scheduling Instructions during a declared Emergency or in anticipation of an Emergency at the discretion of Transmission Provider. Market Participants shall acknowledge Scheduling Instructions issued in accordance with BPM for Resource Adequacy for its LMRs. In the event of an anticipated Emergency where the Transmission Provider does not declare the actual Emergency at least two hours prior to the anticipated Emergency event, Market Participants are not obligated to meet the Scheduling Instructions issued in anticipation of such Emergency and will not be penalized for non-performance. This does not apply to Scheduling Instructions issued after the declaration of an Emergency.

A Market Participant that acknowledges Scheduling Instructions for its LMR(s) as required by the BPM for Resource Adequacy will receive credit for one (1) of the minimum deployments or interruptions required for the LMR for the applicable Season whether or not an Emergency is declared. However, a Market Participant that fails to acknowledge the Scheduling Instructions as required by the BPM for Resource Adequacy will not receive credit for such deployment or interruption for its LMR(s).

An LMR that does not perform consistent with the Market Participant's response to its Scheduling Instructions in the event of an Emergency is subject to the penalty provisions of Section 69A.3.9 and will not receive credit as one (1) of the minimum deployments or interruptions required for such resource for the applicable Season.

Demand Resources (DR) with an Emergency Obligation

Demand Resources registered as either a DRR – Type I or LMR may be deployed to reduce Demand consistent with the submitted Capacity Availability submitted by the Market Participant representing the Demand Resource. A Market Participant shall test, validate, and measure its Demand Resources and submit the results to the Transmission Provider, which shall verify all Demand reduction claimed by a Market Participant, consistent with the procedures specified in the BPM for Demand Response. The accrediting, testing, validation, and Measurement and Verification developed by the Transmission Provider shall take into account any applicable State Regulatory Authority, Regional Entity, or other non-jurisdictional entities' requirements regarding duration, frequency and notification processes for the candidate Demand Resource. A Demand Resource that is sensitive to temperature changes or that is using a Statistical Measurement and Verification methodology must identify, at the time of registration, the extent of such parametric sensitivity to the Transmission Provider with sufficient detail to enable the Transmission Provider to verify whether the Demand Resource would be subject to penalties in Section 69A.3.9 for failure to achieve the targeted Demand reduction amount using the appropriate consumption baseline set forth in Attachment TT. Parametric sensitive analysis must include, but is not limited to, identifying the parameter changes and the parameter's elasticity of the LSE's Load, as further described in the BPM for Demand Response. In accordance with the BPM for Resource Adequacy, the Transmission Provider will qualify a DR for each Season in the upcoming Planning Year.

Demand Resource Eligibility

A Market Participant that possesses ownership or equivalent contractual rights in a Demand Resource can register a Demand Resource as a DRR – Type I or an LMR to participate in the Planning Resource Auction as documented in the BPM for Resource Adequacy. The Market Participant registering the Demand Resource must include the contracts with each end-use customer indicating rights to require the Demand Resource to curtail Load. Notwithstanding, a copy of a contract with an end-use customer will not be required if the Market Participant is the end-use customer. In addition, the Market Participant must meet the following requirements:

a. A Market Participant shall be prohibited from registering into the PRA any component of a Demand Resource that is concurrently registered, in whole or in part, under another DRR, LMR, or EDR whether by the same or a different Market Participant. A Demand Resource registering as an LMR shall not also register as either a DRR or EDR.

b. The Demand Resource must be equal to or greater than 100 kW (a grouping of smaller resources aggregated together as a Load Modifying Resource that is capable of reducing an LSE's Demand for the applicable Season may qualify in meeting this standard).

c. The Demand Resource must be available to be scheduled for a Demand reduction with a notification time requirement: (i) less than or equal to six (6) hours to register in the PRA as a DRR – Type I or an LMR – Type I; or, (ii) less than or equal to thirty (30) minutes to register as an LMR – Type II, in the applicable Seasons.

d. When a Demand Resource is issued Setpoint Instructions or Scheduling Instructions, performance will be evaluated as set forth in Attachment TT using the applicable Measurement and Verification.

e. Once the Setpoint Instruction, Scheduling Instruction, or Firm Service Level is achieved, the Demand Resource must be able to maintain the Setpoint Instruction, Scheduling Instruction, or Firm Service Level for at least four (4) continuous Hours.

f. Unless the Demand Resource is unavailable due to Force Majeure:

(i) A Demand Resource participating as a DRR – Type I or an LMR – Type I that is unavailable to respond to all Setpoint Instructions or Scheduling Instructions shall be subject to the penalties set forth in Section 69A.3.9; and

(ii) A Demand Resource participating as an LMR – Type II that is unavailable to respond to any Scheduling Instructions shall be subject to the penalties set forth in Section 69A.3.9.

This obligation only applies to Seasons during which a Demand Resource clears the Planning Resource Auction.

g. A Demand Resource for which curtailment is not an obligation during Emergency events declared by the Transmission Provider pursuant to the Transmission Provider emergency operating procedures, will not qualify to participate in the PRA as a DRR – Type I or qualify as an LMR.

A Market Participant that submits an Offer into the Day-Ahead and/or Real-Time

Energy and Operating Reserve Markets for a Demand Resource is still subject to the requirements to be available during an Emergency pursuant to the Transmission Provider Emergency Operating Procedures, regardless of the projected or actual Real-Time Energy market LMP.

h. A Demand Resource shall submit Metered data at regular intervals as set forth in Attachment TT.

i. A Market Participant must demonstrate demand reduction capability for each Planning Year on an annual basis as established in the BPM for Resource Adequacy. Beginning with the 2020/2021 Planning Year each Demand Resource must validate its performance by meeting the Transmission Provider's Scheduling Instructions when called upon during the prior Planning Year or conducting a real power test. A Demand Resource for which a real power test is conducted will receive credit as one (1) of the minimum deployments or interruptions required for such resource for the applicable Season of the Planning Year in which such a test occurs.

A Demand Resource may provide operational data, or develop an alternative mechanism, subject to the approval of the Transmission Provider, by which the demand reduction capability can be demonstrated without requiring an actual demand reduction if a real power test is precluded or waived due to one of the two conditions as specified below:

1) Such a real power test is precluded by any applicable regulatory restriction and such a limitation is documented during DR registration; or

2) A Market Participant may waive the obligation to conduct a real power test by notifying the Transmission Provider during DR registration and accepting a penalty equal to three (3) times the Hourly Real-Time Ex Post LMP at the Load CPNode described in and distributed pursuant to Section 69A.3.9. A Demand Resource providing such notice must satisfy credit requirements by March 1 prior to the Planning Year totaling the ICAP value registered, but not tested, multiplied by $2,400/MW, where $2,400 is the product of 3 * 4 * $200 to account for the three (3) times energy penalty assumed under the waiver, the four (4) hours of LMR requirements, and a $200 LMP as a proxy for pricing under emergency conditions.

All existing accredited Demand Resources that neither conduct a real power test nor meet Scheduling Instructions issued by the Transmission Provider during the prior Planning Year must participate in training provided by the Transmission Provider on the deployment of LMRs during the prior Planning Year. Any existing accredited Demand Resource must submit (1) the real power test results, (2) reference performance of Scheduling Instructions for demand reduction when called upon during the calendar year prior to the upcoming Planning Year, (3) alternate testing mechanism, relevant data, and a reference of training participation to the Transmission Provider, or (4) a Demand Resource Deferral Notice pursuant to 69A.3.5(l) and a reference of training participation to the Transmission Provider no later than February 1 prior to such Planning Year for existing accredited DR. For new Demand Resources, (1) a real power test must be conducted and results submitted to the Transmission Provider, (2) alternate testing mechanism must be submitted, or (3) a Demand Resource Deferral Notice must be submitted prior to qualifying as a Demand Resource, but no later than March 1 prior to the PRA in accordance with the BPM for Resource Adequacy. During a transition period that shall apply only to the 2021-2022 Planning Year, Market Participants may submit a Demand Resource Deferral Notice no later than March 31, 2021 for existing accredited Demand Resource, and Market Participants may submit a Demand Resource Deferral Notice no later than March 31, 2021 prior to initially qualifying as a Demand Resource.

j. Market Participants providing physical, regulatory, or contractual limitations of the notice times and availability of Demand Resources must provide appropriate documentation to the Transmission Provider in accordance with the BPM for Resource Adequacy.

h. A Market Participant may defer the obligation to conduct a real power test, as set forth in section 69A.3.5(i), by providing a Demand Resource Deferral Notice to the Transmission Provider in writing and signed by an officer of the company no later than February 1st prior to the Planning Year. During a transition period that shall apply only to the 2021-2022 Planning Year, Market Participants may submit a Demand Resource Deferral Notice no later than March 31, 2021 for existing accredited Demand Resource, and Market Participants may submit a Demand Resource Deferral Notice no later than March 31, 2021 prior to initially qualifying as a Demand Resource. The Demand Resource Deferral Notice shall contain: (1) the expected Demand Resource test value (in megawatts) from such Demand Resource and if the Demand Resource is new, the LBA or external BA where it is represented; and (2) appropriate information validating that real power test results will be submitted to the Transmission Provider by the last Business Day of May prior to the Planning Year. A Market Participant that provides a Demand Resource Deferral Notice must satisfy credit requirements by March 1 prior to the Planning Year totaling the amount of Demand Resource test value provided in the Demand Resource Deferral Notice multiplied by $2,400/MW, where $2,400 is the product of 3*4* $200 to account for the three (3) times energy penalty assumed under the deferral, the four (4) hours of LMR requirements, and a $200 LMP as a proxy for pricing under emergency conditions. During a transition period that shall apply only to the 2021-2022 Planning Year, Market Participants that have elected to submit a Demand Resource Deferral Notice must satisfy credit requirements by March 31, 2021. If the Market Participant submits the real power test results on or before the last Business Day of May prior to the Planning Year that are equal to or greater than the expected Demand Resource test value, then the Transmission Provider will adjust the Market Participant's credit requirement to account for these changes within twenty (20) Business Days after that real power test is submitted. In the event ZRCs associated with a Planning Resource for which Demand Resource testing has been successfully deferred are unconverted in accordance with section

69A.7.3, the Market Participant may provide notice to the Transmission Provider that it wishes to forfeit the deferred Demand Resource value, in which case the Transmission Provider will adjust the Market Participant's Demand Resource value and credit requirement within twenty (20) Business Days. A Market Participant that provides a Demand Resource Deferral Notice and that either (1) has not submitted any real power test result for such Demand Resource by the last Business Day of May prior to the Planning Year, or (2) has submitted a real power test result by the last Business Day of May prior to the Planning Year that demonstrates fewer megawatts are available than the expected Demand Resource test value submitted in the Demand Resource Deferral Notice, shall be subject to a penalty equal to three (3) times the Hourly Real-Time Ex Post LMP at the Load CPNode for any such deficiency described in and distributed pursuant to Section 69A.3.9. In addition, such Market Participant shall not have their credit released until a real power test result demonstrating the availability of all megawatts submitted in the Demand Resource Deferral Notice is submitted and verified by the Transmission Provider, or the end of the Planning Year, whichever is earlier.

Behind the Meter Generation Eligibility

1. A Market Participant that possesses ownership or equivalent contractual rights in a behind the meter generator can register such behind the meter generator as a DRR – Type I or an LMR to participate in the Planning Resource Auction as documented in the BPM for Resource Adequacy. A behind the meter generator registered as a DRR – Type I or an LMR is a BTMG. The Market Participant registering the BTMG must include the contracts with each end-use customer indicating rights behind the BTMG to generate behind-the-meter generation. Notwithstanding, a copy of a contract with an end-use customer will not be required if the Market Participant is, or has non-contractual legal rights to control, the end use customer. In addition, the Market Participant must meet the following requirements:

    a. A Market Participant shall be prohibited from registering into the PRA any BTMG that is concurrently registered, in whole or in part, under another DRR, LMR, or EDR, whether by the same or a different Market Participant. A BTMG registering as an LMR shall not also register as a DRR or EDR.

    b. The BTMG must be equal to or greater than 100 kW (a grouping of smaller resources aggregated together as a Load Modifying Resource that is capable of reducing an LSE’s Demand for the applicable Season may qualify in meeting this standard).

    c. A behind the meter generator for which curtailment is not an obligation during Emergency events declared by the Transmission Provider will not qualify to participate in the PRA as a DRR – Type I or qualify as an LMR.

A Market Participant that submits an Offer in the Day-Ahead Market and/or Real-Time Energy and Operating Reserve Markets for a BTMG is still subject to the requirement to be available during an Emergency pursuant to the Transmission Provider Emergency Operating Procedures, regardless of the projected or actual Real-Time Energy Market LMP.

d. A Market Participant shall demonstrate GVTC capability for applicable Season in each Planning Year on an annual basis as established in the BPM for Resource Adequacy, and by submitting the GVTC results to the Transmission Provider no later than October 31 prior to such Planning Year for existing accredited BTMG unless the Transmission Provider has granted an extension pursuant to Section 69A.3.6.1.j. All new BTMGs or an existing accredited BTMG that has an increased installed capacity shall submit their GVTC to the Transmission Provider prior to qualification, but no later than March 1 prior to the PRA as established in the BPM for Resource Adequacy.

e. A Market Participant shall submit generator availability data (including, but not limited to, NERC GADS information) into a database provided by the Transmission Provider and as established in the BPM for Resource Adequacy. A Market Participant is not required to report generator availability data based on GVTC for a BTMG less than 10 MW if the Market Participant has never provided such data for such BTMG. A Market Participant that begins reporting generator availability data based upon GVTC for a BTMG that is less than 10 MW must continue to report such data.

f. A BTMG must be available to provide Energy with a notification time requirement: (i) of six (6) hours or less notice if registering in the PRA as a DRR – Type I or an LMR – Type I; or (ii) with thirty (30) minutes or less notice if registering as an LMR – Type II in the applicable Seasons.

g. A Market Participant shall demonstrate that the BTMG is able to sustain energy production at the MW level being registered for at least four (4) continuous Hours;

h. Unless unavailable due to Force Majeure:

(i) A BTMG participating as a DRR – Type I or LMR – Type I that is unavailable to respond to all Setpoint Instructions or Scheduling Instructions shall be subject to the penalties set forth in Section 69A.3.9; and

(ii) A BTMG participating as an LMR – Type II that is unavailable to respond to any Scheduling Instruction shall be subject to the penalties set forth in Section 69A.3.9.

This obligation only applies during Seasons which the BTMG clears the Planning Resource Auction.

i. A BTMG shall submit Metered data at regular intervals as set forth in Attachment TT.

j. A Market Participant registering a BTMG may not register as a DRR – Type II or Non-Emergency BTMG for three years (3) Planning Years. After three (3) Planning Years, a Market Participant may commit to participate as a BTMG for an additional three (3) Planning Years or may elect to participate as a DRR – Type II or Non-Emergency BTMG. A BTMG may opt to participate as a DRR – Type I or LMR at any time by satisfying the requirement of such participation option.

k. A Market Participant for a BTMG required to submit GVTC results must use Reasonable Efforts to submit GVTC by October 31 prior to the upcoming Planning Year. If circumstances prevent the Market Participant from submitting the GVTC results for the BTMG by October 31, the Market Participant must notify the Transmission Provider no later than five (5) Business Days after October 31 and request an extension. The extension request must include a reasonable explanation and justification for missing the deadline and an expected completion date prior to the upcoming Planning Year. The Transmission Provider will review each extension request on a case by case basis to determine whether or not to approve or deny the request to extent the GVTC deadline. Denial of an extension will not preclude the Market Participant for the BTMG from utilizing the ICAP Deferral process as described in Section 69A.7.9.

2. Installed Capacity (ICAP) Deferral

If a Market Participant for a BTMG has not completed GVTC testing by the deadlines provided in 69A.3.6.1.d, is not expected to demonstrate deliverability, or is otherwise not expected to demonstrate commercial operation prior to March 1, ZRCs from such capacity may be used the PRA, in a FRAP (including through bilateral ZRC transactions) or in an RBDC Opt Out, subject to the notification, credit, and non-compliance provisions of Section 69A.7.9.

Transmission Provider Initiated Testing of Demand Resources

1. A Demand Resource participating as a DRR or a LMR that is registered in the PRA shall be subject to a Transmission Provider initiated test according to the following requirements:

   a. Test frequency:

      i. A Demand Resource using an Attachment TT defined Statistical Measurement and Verification methodology shall be tested once per Planning Year;

      ii. A Demand Resource participating as a DRR or LMR – Type I shall be tested once per three (3) Planning Years;

      iii. A Demand Resource participating as an LMR – Type II shall be tested once per Planning Year. A Market Participant representing a Demand Resource participating as an LMR – Type II may request a Transmission Provider initiated test opt out as set forth in Section 69A.3.8.2; or

      iv. Notwithstanding the provisions above, the Transmission Provider may test a resource at any time due to its non-performance.

   b. A Demand Resource that has successfully deployed in response to a Setpoint Instruction or Scheduling Instruction issued during an Emergency in either the past one (1) or three (3) Planning Years as applicable pursuant to sub-section a. above, shall count as a successful Transmission Provider initiated test.
   Provided there are no deployment failures for a Demand Resource participating as an LMR during the 2025/2026, 2026/2027, and 2027/2028 Planning Years, full

response to Setpoint Instructions or Scheduling Instructions issued during an Emergency shall count as a successful Transmission Provider initiated test for the first one (1) or three (3) Planning Year cycle, as applicable, beginning with the 2028/2029 Planning Year.

c. A new Demand Resource participating as a DRR or an LMR shall undergo a Transmission Provider initiated test during the first Planning Year it is registered for the PRA.

d. A Market Participant shall receive at least 24 hours notification prior to the initiation of a Transmission Provider initiated test. Additional requirements regarding the Transmission Provider initiated test shall be set forth in the BPM for Resource Adequacy.

2. A Demand Resource participating as an LMR – Type II may opt out of the annual Transmission Provider initiated test requirement if it has responded to all Scheduling Instructions and successfully passed all Transmission Provider initiated tests, within the past three (3) Planning Years.

a. If opting out of a test, a Demand Resource opting out of the test shall be subject to increased real-time penalties equal to the product of Pricing VOLL and the amount of specified Demand reduction, measured in MWh, not achieved in response to a Setpoint Instruction or Scheduling Instruction issued during an Emergency, in addition to any other penalty provisions set forth in 69A.3.9.

3. A Demand Resource will be deemed to have fully satisfied the Transmission Provider initiated test if the resource has met its performance obligations, as set forth in

Attachment TT, within the registered notification time, and maintained the Demand reduction or Firm Service Level as applicable for four (4) continuous hours.

4. A Demand Resource will have partially failed the Transmission Provider initiated test if the Demand Resource fully deploys outside of the registered notification time and within six (6) hours of initiating the test for participating as DRR – Type I or LMR – Type I, within thirty (30) minutes of initiating the test for participating as LMR – Type II, and within the Offered Shut-Down time for participating as a DRR – Type II. A partial failure of a Transmission Provider initiated test will result in:

   a. The Demand Resource being charged the product of the amount of the Demand shortfall, measured in MW at the Hour equal to the initiation of the Transmission Provider test plus the registered response time, and the Auction Clearing Price, for the lesser of:

      i. The remainder of the Season; or

      ii. Such time as the Demand Resource fully deploys in response to a Setpoint Instruction or Scheduling Instruction during a Transmission Provider declared Emergency.

   b. The Transmission Provider will adjust the resource's registered response time to reflect its tested response. A Market Participant must provide evidence to the Transmission Provider to register such resource with a response time less than the response time achieved during the Transmission Provider initiated test during subsequent Planning Years.

   c. The Demand Resource may be tested in subsequent Seasons during the same

Planning Year.

d. The Demand Resource shall be tested in the subsequent Planning Year.

5. A Transmission Provider initiated test shall be deemed to be fully failed if the Demand Resource failed to achieve its required Demand reduction, as measured per the applicable Attachment TT Measurement and Verification identified during the registration of the resource, within six (6) hours of initiating the test for participating as DRR – Type I or LMR – Type I, within thirty (30) minutes of initiating the test for participating as LMR – Type II, and within the Offered Shut-Down time for participating as a DRR – Type II.

a. A Demand Resource experiencing a complete test failure will be subject to penalties equal to the product of the cleared ZRCs and the ACP for the entire Season in which the test was performed.

b. The Transmission Provider shall perform a test in the subsequent Season the resource has cleared ZRCs.

c. A resource failing two (2) tests during a single Planning Year shall be fully disqualified for the remainder of the Planning Year and shall pay 2.748 times the applicable LRZ's CONE multiplied by the amount of cleared ZRCs for each Season.

Penalty Provisions for LMRs

Unless an LMR is unavailable as a result of maintenance requirements, for reasons of Force Majeure, or because the number of required deployments based on the registered number has been reached, the Market Participant representing the entity that had ZRCs from LMRs that cleared in the PRA, were used in a FRAP, or were used in an RBDC Opt Out will be subject to the following penalties in the event the LMR is called upon during an Emergency as declared by the Transmission Provider and the LMR fails to perform in accordance with its Market Participant's response to such Market Participant's Scheduling Instructions. The penalties defined below will only apply to the portion of the Market Participant's response to such Market Participant's Scheduling Instruction that is not followed during the Emergency declaration and will only be assessed by the Transmission Provider after giving the operator of the LMR an opportunity to provide documentation of the specific circumstances that would justify exemption from such penalties. There will not be an LMR penalty assessed for any portion of the Scheduling Instruction which had already been accomplished by an LMR for other reasons (*e.g.*, for economic considerations, self-scheduling at or above the credited amount of BTMG or local reliability concerns in accordance with instructions from the Local Balancing Authority) at the time the request for interruption is made by the Transmission Provider. Likewise, for certain Demand Resources that are temperature dependent (*e.g.*, a Demand Resource program involving air conditioning load), the specified Demand reduction may be adjusted in a manner defined in the measurement and verification procedures developed by the Transmission Provider to reflect the circumstances at the time a Demand Resource is called upon to reduce Demand.

a. The Transmission Provider shall assess the responsible Market Participant the costs that were otherwise incurred to replace the deficient Planning Resource at the time the Market Participant's LMR is called upon by the Transmission Provider and does not respond in full or in part consistent with the Market Participant's response to MISO's Scheduling Instructions. These costs will be the product of the amount of specified Demand reduction not achieved and the Hourly Real-Time Ex Post LMP at the Load CPNode, plus any applicable Revenue Sufficiency Guarantee charges. The Transmission Provider shall allocate any such penalty revenues only to the Market Participants representing the LSEs in the Local Balancing Authority Area(s) that experienced the Emergency that required the use of an LMR. Such revenues shall be distributed on a Load Ratio Share basis. For any situation where either an LMR does not respond to an interruption request, including those circumstances where the LMR is claimed to be unavailable as a result of maintenance requirements or for reasons of Force Majeure, the Transmission Provider shall initiate an investigation with the Market Participant which has registered the Demand Resource or BTMG and was qualified as an LMR into the cause of the LMR not being available when called upon to reduce Demand. If deemed appropriate by the Transmission Provider, the Transmission Provider will disqualify the Demand Resource or BTMG from further use as an LMR for the remainder of the current Planning Year, and will discontinue payment of the applicable ACP for the remainder of the current Planning Year when the LMR was unavailable. If such

LMR was used in a FRAP or cleared in the PRA or used in an RBDC Opt Out, then the Market Participant will be charged the applicable ACP for the remainder of the current Planning Year for the Unforced Capacity of the LMR. The revenues collected will be distributed on a *pro rata* basis in such LRZ based upon an LSE's Final PRMR.

b. In the event the same LMR is unavailable on a second occasion (with at least a separation period of 24 hours) when called upon to respond to Scheduling Instructions, except for a validated circumstance of maintenance requirements or for reasons of Force Majeure, the Market Participant taking credit for that LMR shall make the same penalty payment as indicated in Section 69A.3.9.a above, and the Demand Resource or BTMG will no longer qualify as an LMR and will not receive the applicable ACP for the remainder of the current Planning Year and will not be eligible for LMR status for the next Planning Year. If such LMR was used in a FRAP or cleared in the PRA or used in an RBDC Opt Out, then the Market Participant will be charged the applicable ACP for the remainder of the current planning year for the Unforced Capacity of the LMR. The revenues collected will be distributed on a *pro rata* basis in such LRZ based upon an LSE's Final PRMR.

Non-Emergency Behind the Meter Generation Eligibility

1. A Market Participant that possesses ownership or equivalent contractual rights in a behind the meter generator can register such behind the meter generator as a Non-Emergency BTMG to participate in the Planning Resource Auction as documented in the BPM for Resource Adequacy. The Market Participant registering the Non-Emergency BTMG must include the contracts with each behind the meter generator indicating rights behind the Non-Emergency BTMG to generate behind-the-meter generation. Notwithstanding, a copy of a contract with a behind the meter generator will not be required if the Market Participant is, or has non-contractual legal rights to control, the behind the meter generator. In addition, the Market Participant must meet the following requirements:

   a. A Market Participant shall be prohibited from registering into the PRA any Non-Emergency BTMG that is concurrently registered, in whole or in part, whether by the same or a different Market Participant.

   b. The Non-Emergency BTMG must be equal to or greater than 100 kW (a grouping of smaller resources aggregated together as a single Non-Emergency Behind the Meter Generation resource may qualify in meeting this standard).

   c. At registration, a Market Participant registering a Non-Emergency BTMG must commit to participate as a Non-Emergency BTMG for three (3) Planning Years. After three (3) Planning Years, a Market Participant may commit to participate as a Non-Emergency BTMG for an additional three (3) Planning Years or may elect to participate as a DRR – Type I or an LMR. A resource participating as a Non-

Emergency BTMG may opt to participate as a DRR – Type II Resource at any time by satisfying the requirements of a DRR – Type II.

d. A Non-Emergency BTMG has no obligation to respond to a Transmission Provider Setpoint Instruction or Scheduling Instruction.

e. A Market Participant registering a Non-Emergency BTMG shall demonstrate GVTC capability for the applicable Season in each Planning Year on an annual basis as established in the Business Practices Manual for Resource Adequacy. A Market Participant of an existing Non-Emergency BTMG must submit the GVTC results to the Transmission Provider no later than October 31 prior to such Planning Year. If circumstances prevent the Market Participant from submitting the GVTC results for the Non-Emergency BTMG by October 31, the Market Participant must notify the Transmission Provider no later than five (5) Business Days after October 31 and request an extension. The extension request must include a reasonable explanation and justification for missing the deadline and an expected completion date prior to the upcoming Planning Year. The Transmission Provider will review each extension request on a case by case basis to determine whether or not to approve or deny the request to extend the GVTC deadline. Denial of an extension will not preclude the Market Participant for the Non-Emergency BTMG from utilizing the ICAP Deferral process as described in Section 69A.7.9.

A Market Participant of all new Non-Emergency BTMGs, or an existing accredited Non-Emergency BTMG that have increased installed capacity, shall submit their GVTC to the Transmission Provider prior to qualification, but no later than March 1 prior to the PRA.

A Market Participant may request an extension of these deadlines pursuant to Section 69A.3.10.2.

f. A Market Participant shall submit generator availability data (including, but not limited to, NERC GADS information) into a database provided by the Transmission Provider and as established in the Business Practices Manual for Resource Adequacy. A Market Participant is not required to report generator availability data based on GVTC for a Non-Emergency BTMG less than 10 MW if the Market Participant has never provided such data for such Non-Emergency BTMG. A Market Participant that begins reporting generator availability data based upon GVTC for a Non-Emergency BTMG that is less than 10 MW must continue to report such data.

g. A Market Participant for Non-Emergency BMTG shall submit Meter data at regular intervals as set forth in Attachment TT.

2. Installed Capacity (ICAP) Deferral

If a Market Participant for a Non-Emergency BTMG has not completed GVTC testing by the deadlines provided in 69A.3.10(e), is not expected to demonstrate deliverability, or is otherwise not expected to demonstrate commercial operation prior to March 1, ZRCs from such capacity may be used the PRA, in a FRAP (including through bilateral ZRC transactions), or in an RBDC Opt Out, subject to the notification, credit, and non-compliance provisions of Section 69A.7.9.

Planning Resource Capacity Values

In order for the Transmission Provider to account for resource performance and availability, Capacity Resources, Demand Response Resources – Type I, Load Modifying Resources, and Non-Emergency Behind the Meter Generation will be given a capacity value for each applicable Season based on the Seasonal Accredited Capacity calculation applicable to its Resource type; and EE Resources will be given capacity values based on the measurement and verification data provided for such resources, as provided in the BPM for Resource Adequacy.

Seasonal Accredited Capacity of Capacity Resources

The Transmission Provider will determine the Seasonal Accredited Capacity for each Capacity Resource.

a. The Seasonal Accredited Capacity for a Capacity Resource that is a Generation Resource, but not a Dispatchable Intermittent Resource, Intermittent Generation, Electric Storage Resource, External Resource, or Use Limited Resource, is based on an evaluation of the type and volume of interconnection service, GVTC value, and Real-Time offered availability of such Generation Resource or Electric Storage Resource for each Season as set forth in Schedule 53.

b. The Seasonal Accredited Capacity for a Capacity Resource that is an External Resource, but not a Dispatchable Intermittent Resource, Intermittent Generation or Use Limited Resource, is based on the GVTC value and $XEFOR_d$ values of such External Resource for each Season. External Resources that are not required to report generator availability data will have a forced outage rate based on the class average forced outage rate of the resource type.

c. The Transmission Provider will determine the Seasonal Accredited Capacity for a DRR – Type II that qualifies as a Capacity Resource, for each Season, as set forth in Schedule 53B.

d. The Seasonal Accredited Capacity for a Capacity Resource that is a Dispatchable Intermittent Resource or Intermittent Generation will be determined by the Transmission Provider based on historical performance, availability, and type and volume of interconnection service, for each Season in accordance with the BPM for Resource Adequacy.

e. The Seasonal Accredited Capacity value for a Capacity Resource that is a Hybrid Resource will be established by the Transmission Provider based on the sum of the Seasonal Accredited Capacity values of its respective Electric Facilities for the production and/or storage for later injection of electricity, up to the level of firm interconnection service, prior to a minimum amount of operating data becoming available. Once sufficient operation data is available, as defined in the BPM, the Seasonal Accredited Capacity value for a Hybrid Resource will be determined by the Transmission Provider based on historical performance, availability, and type and volume of interconnection service, for each Season in accordance with the BPM.

f. The Seasonal Accredited Capacity of a Capacity Resource that is an Electric Storage Resource will be established by the Transmission Provider based on an evaluation of the type and volume of interconnection service, a GVTC value based upon a power and energy test, and an $XEFOR_d$. Electric Storage Resources that are not required to report generator availability data will have an $XEFOR_d$ rate based on their class average forced outage rate.

g. The Seasonal Accredited Capacity for a Capacity Resource that is a Use Limited Resource will be determined by the Transmission Provider based on the type and volume of interconnection service, the GVTC and $XEFOR_d$ values of such Use Limited Resource in accordance with the BPM for Resource Adequacy.

Seasonal Accredited Capacity of Demand Resources

The Transmission Provider will determine the appropriate Seasonal Accredited Capacity value for Demand Resources that qualify as a Planning Resource as established in Schedule 53B.

Seasonal Accredited Capacity of Behind the Meter Generation and Non-Emergency Behind the Meter Generation

The Transmission Provider will determine the Seasonal Accredited Capacity for each BTMG and Non-Emergency BTMG as set forth in Schedule 53B. If such BTMG or Non-Emergency BTMG is interconnected to the Transmission System, the Transmission Provider will consider the type and volume of interconnection service when determining the Seasonal Accredited Capacity.

EE Resources

The Seasonal Accredited Capacity for a qualified EE Resource will be determined by the Transmission Provider based upon submitted measurement and verification documents, as provided in the BPM for Resource Adequacy.

Attributes of ZRCs

A Market Participant that owns or possesses equivalent contractual rights to a qualified Planning Resource can convert the convertible Seasonal Accredited Capacity of the Resource (Seasonal Accredited Capacity MW) as determined in section 69.A.3.1.g into ZRCs through the MECT in order to offer such ZRCs into a PRA. Market Participants also can unconvert and/or transfer ZRCs through the MECT to another Market Participant, as described in the BPM for Resource Adequacy.

A. Eligibility for Zonal Resource Credits for a Capacity Resource that is a Planning Resource that is not Intermittent Generation or Dispatchable Intermittent Resource.

For a Capacity Resource that is not Intermittent Generation or Dispatchable Intermittent Resource the amount of Capacity that is eligible to be converted to Zonal Resource Credits shall be the convertible Seasonal Accredited Capacity value of the Capacity Resource. The convertible Seasonal Accredited Capacity shall be determined by:

i. Determining the Installed Capacity;

ii. Determining the Seasonal Accredited Capacity of the Capacity Resource;

iii. Allocating the Capacity Resource's Seasonal Accredited Capacity value where:

   a. If the Capacity Resource has only Energy Resource Interconnection Service, the Seasonal Accredited Capacity will be allocated to the Capacity Resource's Energy Resource Interconnection Service Seasonal Accredited Capacity value, which will be calculated by multiplying the lesser of the Capacity Resource's ICAP or Energy Resource Interconnection Service by SAC divided by ICAP;

b. If the Capacity Resource has both Network Resource Interconnection Service and Energy Resource Interconnection Service, the Seasonal Accredited Capacity will be allocated first to the Capacity Resource's Network Resource Interconnection Service Seasonal Accredited Capacity value, which will be calculated by multiplying the lesser of the Capacity Resource's ICAP or Network Resource Interconnection Service by SAC divided by ICAP, as provided below:

$NRIS\ SAC = MIN\ (NRIS, ICAP) \times (SAC/ICAP)$

c. Any remaining total Seasonal Accredited Capacity value will then be allocated to Energy Resource Interconnection Service Seasonal Accredited Capacity as provided below:

$ERIS\ SAC = MAX\ (0, (ICAP\text{-}NRIS)) \times (SAC/ICAP)$

d. The resulting Network Resource Interconnection Service Seasonal Accredited Capacity value shall be eligible to be converted into Zonal Resource Credits; and

e. The resulting Energy Resource Interconnection Service Seasonal Accredited Capacity value that is coupled with firm Transmission Service shall be eligible to be converted into Zonal Resource Credits up to the Energy Resource Interconnection Service Unforced Capacity value of the Capacity Resource, by multiplying the firm Transmission Service amount by SAC divided by ICAP.

B. Eligibility for Zonal Resource Credits for a Capacity Resource that is an Intermittent Generation or Dispatchable Intermittent Resource

For Intermittent Generation and Dispatchable Intermittent Resources that are Capacity Resources, the amount of Capacity eligible to be converted to Zonal Resource Credits shall be the convertible Seasonal Accredited Capacity value of the Intermittent Generation or Dispatchable Intermittent Resource, which is equal to the total Seasonal Accredited Capacity value multiplied by the quotient of the deliverability adjusted Capacity factor divided by the peak performance Capacity factor of the Capacity Resource where:

a. the deliverability-adjusted capacity factor is the average of the actual Energy output capped at the demonstrated deliverability of the Intermittent Generation or Dispatchable Intermittent Resource determined in Section 69A.3.1.g during the highest system peak load observances for each Season that the Capacity Resource was in service divided by the Installed Capacity of the Capacity Resource; and,

b. the existing peak performance Capacity factor is the average of the actual Energy output during the highest system peak load observances for each Season that the Capacity Resource was in service divided by the Installed Capacity of the Capacity Resource.

C. Eligibility for Zonal Resource Credits for a Capacity Resource that is a Distributed Energy Aggregated Resource

For Distributed Energy Aggregated Resources that are Capacity Resources, the amount of Capacity eligible to be converted to Zonal Resource Credits shall be the convertible Seasonal

Accredited Capacity value of the Distributed Energy Resources within the aggregation according to their resource type as determined in section 69A.3.1.g.

Capacity Resource Must Offer and Performance Requirements

a. Market Participants that convert Seasonal Accredited Capacity from Capacity Resources into ZRCs that clear in a Season in the PRA or are used in a FRAP (and that do not replace such ZRCs in accordance with Section 69A.3.1.h) or used in an RBDC Opt Out, including Capacity Resources that are the subject of Diversity Contracts, must submit Self-Schedules or Offers for Energy, and Contingency Reserve if qualified, and offers for Short-Term Reserve if qualified, for the Installed Capacity value of the Capacity Resources converted to ZRCs and clear in a Season in the PRA or used in a FRAP or used in an RBDC Opt Out for each Hour of each Day during the applicable Season in the Planning Year, in the Day-Ahead Energy Market and all pre Day-Ahead and the first post Day-Ahead Reliability Assessment Commitment process. This must offer obligation does not apply to the extent that the Capacity Resource is unavailable due to a full or partial forced or scheduled outage, in accordance with the BPM for Resource Adequacy and the BPM for Outage Operations. Additionally, this must offer obligation is modified to the extent the Capacity Resource is provided an operating limitation, such as thermal, voltage, or stability limits referenced in the BPM for Outage Operations, by the Transmission Provider or Transmission Operator to preserve the reliability of the Transmission System, that is lower than the must offer obligation described above, for the duration of such limitation.

Any such Capacity Resource with full or partial Generator Planned Outages that exceeds thirty-one (31) Days during any Season will be deemed not to have met its performance requirement for any Days greater than thirty-one (31) Days and must replace ZRCs in accordance with Section 69A.3.1.h, provided that Capacity Resources subject to Diversity Contracts that are unavailable for greater than thirty-one (31) Days in total during any Season, will be deemed not to have met its performance requirement and will be subject to the ZRC replacement provisions set forth in Section 69A.3.1.h. Self-Schedules or Offers for Energy must be made consistent with requirements specified in Sections 39 and 40 of this Tariff as well as in the BPM for Resource Adequacy and the Business Practices Manual for Energy and Operating Reserves Markets. Partial or full forced or scheduled outages or derates of Capacity Resources must be reported in the Transmission Provider's Outage Scheduler, as described in further detail in the Business Practices Manual for Outage Operations. Must offer requirements specified in the BPM for Resource Adequacy will reflect resource operational limitations, including those related to Use Limited Resources, fuel limited, energy output limited or Intermittent Generation and including all state regulations and laws, including but not limited to, state safety standards, planning reserve margins, or the enforcement thereof. The Transmission Provider will monitor compliance with must offer requirements in accordance with the BPM for Resource Adequacy.

b. If a Capacity Resource that has ZRCs cleared in the PRA during any Season or is used in a FRAP during any Season or used in an RBDC Opt Out is capable of performing but fails to perform when called upon by the Transmission Provider for an Emergency, the Transmission Provider shall assess the owner of such Capacity Resource the costs that were otherwise incurred to replace the energy from the deficient Capacity Resource at the time that the Capacity Resource is called upon by the Transmission Provider and does not respond in full or in part, for each day of non-performance of such Capacity Resource, provided that the planned or forced outage of the Capacity Resource is not properly reported in the Transmission Provider's Outage Scheduler, as set forth in the Business Practices Manual for Outage Operations. These costs will be the product of the amount of qualified ZRCs not achieved and the real-time LMP at the Capacity Resource's CPNode, plus any applicable related Revenue Sufficiency Guarantee charges. The Transmission Provider shall allocate any such revenues to the Market Participants representing the LSEs in the Local Balancing Authority Area(s) that experienced the Emergency. Such revenues shall be distributed on a Load Ratio Share basis.

c. Market Participants must input all Energy Efficiency Resource and Load Modifying Resource information into the MECT at least seven (7) Business Days prior to the Planning Resource Auction.

State RAR Standards

The Transmission Provider will assist states in meeting any state resource adequacy standards by providing relevant MECT information as available and as may be requested by states, subject to the data confidentiality provisions in Section 38.9 of this Tariff. Nothing in the RAR shall prohibit any state from requesting data relating to state safety standards, planning reserve margins, or the enforcement thereof.

Information regarding RAR Obligations

The Transmission Provider will maintain databases and will report to states and the affected LSEs, upon request, aggregated, non-confidential information regarding jurisdictional LSEs' RAR obligations during relevant time periods. Confidential Data regarding RAR status will be provided to states only in accordance with the data confidentiality provisions in Section 38.9 of this Tariff.

Facilitation of a Bilateral Capacity Bulletin Board

The Transmission Provider shall maintain an electronic bulletin board platform that may be used by Market Participants to facilitate voluntary bilateral ZRC transactions and to monitor the conversion of Seasonal Accredited Capacity to ZRCs.

Facilitation of LSE's RAR Information

The Transmission Provider shall, upon request, submit RAR information to the applicable RE, Electric Reliability Organization, state (in the case of an LSE subject to regulation or using delivery services rates, terms or conditions established by such State Regulatory Authority) or to the Commission, subject to the provisions of Section 38.9 of this Tariff.

Reliability Based Demand Curve Procedures

A. Translation of MRI Curves to RBDCs

The following process will be utilized to determine the RBDC for the Transmission Provider Region for each Season of the upcoming Planning Year. The MRI Curves for the Transmission Provider Region as described in Section 68A.9 will be multiplied by a scaling factor measured in $/MWh. The scaling factor for an RBDC is calculated to support ACPs that achieve annual Net CONE when the Transmission Provider Region is at the reliability requirement established by the LOLE analysis for each Season. LOLE risk across the Seasons is modeled as described in Section 68A.2.1. The scaling factors shall be determined as set forth in the Business Practices Manual for Resource Adequacy.

The process used to determine the RBDCs for each of the First Planning Area and the Second Planning Area for each Season in the Planning Year is similar to the process used for developing the RBDC curve for the Transmission Provider Region.

B. Monte Carlo Analysis

Every three Planning Years, the Transmission Provider will evaluate the ability of RBDCs, through probabilistic analysis, to reliably serve the Transmission Provider Region's Demand while supporting ACPs that achieve annual Net CONE when the Transmission Provider Region is at the reliability requirement established by the LOLE analysis for each Season. The probabilistic analysis shall use a Monte Carlo study that assumes there are no internal transmission limitations within the Transmission Provider Region.

The Monte Carlo analysis will model both in-market supply and demand based on historic supply and demand variability, respectively, observed through a minimum of the three most recent PRAs. The Monte Carlo model will produce seasonal clearing prices and quantities with each draw. Overall model results will be assessed by comparing the average of seasonal prices from the study against the estimate of Net CONE described in section 69A.8. The scaling factor is adjusted in each successive Monte Carlo simulation so that long run equilibrium conditions are ultimately achieved, indicated by the average of seasonal prices from the study equal to the estimate of Net CONE. Net CONE values used for the Monte Carlo analysis will be the simple arithmetic average of all LRZ Net CONE values.

A separate Monte Carlo analysis will be performed to evaluate the RBDCs for the First Planning Area and the Second Planning Area. Separate scaling factors will be used in the Monte Carlo analysis for each of the First Planning Area and the Second Planning Area that supports achievement of Net CONE values for the corresponding Planning Area, indicated by the average of seasonal capacity prices under long run equilibrium conditions. Net CONE values used in the Monte Carlo analysis for the RBDCs for the First Planning Area and the Second Planning Area will be the simple arithmetic average of LRZ Net CONE values for the specific LRZs in the corresponding Planning Area.

Planning Resource Auction

Within twenty (20) Business Days after the last Business Day in March, the Transmission Provider will conduct a PRA to determine the ACP in each LRZ and ERZ for the upcoming Planning Year which begins on June 1st. The Transmission Provider will post the results of the PRA on its website, consistent with the standards and procedures set forth in the BPM for Resource Adequacy. The Transmission Provider shall ensure that each Market Participant submitting a ZRC Offer is qualified to submit such an offer consistent with the Transmission Provider's creditworthiness provisions. The Transmission Provider will ensure that the LCR, the CEL and CIL are respected for each LRZ, the CEL is respected for each ERZ, and the SREC and the SRIC are respected for each SRRZ, if applicable, when conducting the PRA.

PRA Procedures

a. **Participating ZRCs in the PRA:** All Market Participants that own or have contractual rights to the Planning Resources that are represented within an LRZ or ERZ and have converted Seasonal Accredited Capacity to ZRCs, will have an option to (consistent with withholding provisions) submit offers into the PRA for such ZRCs, to the extent that the Market Participant has not submitted a FRAP, or RBDC Opt Out, as described in Section 69A.9. Owners of jointly-owned facilities can individually offer their share of any such resources into the PRA, either as self-schedule price takers or with specific offers, or use their share of such resources as part of their FRAPs, or RBDC Opt Outs. These ZRC Offers must be submitted in price/quantity pairs on a monotonically increasing basis expressed as MW-day and must consist of a stepped ZRC Offer curve of up to five (5) segments for each Planning Resource. ZRC Offers shall be submitted to the Transmission Provider via the MECT during the PRA offer window. Only ZRCs that are not otherwise committed for the remainder of the Planning Year are permitted to participate in the PRA. The PRA offer window shall begin at 8:00 am EPT three (3) Business Days before the last Business Day in March and shall end at 6:00 pm EPT on the last Business Day in March. The Transmission Provider may extend or reopen the PRA offer window based on unanticipated events that: (i) interfere with the Transmission Provider's ability to receive and/or process accurate and complete ZRC Offers or (ii) are otherwise likely to have a widespread negative impact on the results of the PRA. The Transmission Provider shall notify Market Participants and post such notice of any extension or reopening of the PRA on its website. The notice shall state the extension or reopening's circumstances, rationale, and duration. The price associated with these ZRC Offers cannot exceed the annual CONE value divided by the number of days in the Season for the LRZ where the ZRC is represented. ZRC Offers from External Resources represented in ERZs, which are connected to single SRRZ, cannot exceed the greatest CONE value of all LRZs in respective SRRZ. ZRC Offers from External Resources represented in ERZs, which are connected to multiple SRRZs or are not connected to any SRRZs, cannot exceed the greatest CONE value of all LRZs in those connected SRRZs. Owners of ZRCs may bilaterally sell or buy ZRCs; however if a ZRC has cleared in the auction, the Market Participant that registered the Planning Resource that is the subject of such ZRC shall be responsible for complying with all Tariff requirements. The Independent Market Monitor will review the actions of owners/operators of all qualified Seasonal Accredited Capacity from Planning Resources and conversion to ZRCs to evaluate potential withholding of Planning Resources from the PRA, consistent with Module D. External Resources, including Generation Resources pseudo-tied into the MISO Balancing Authority Area, will be granted ZRCs in the applicable External Resource Zone. Notwithstanding the above, External Resources located within a Coordinating Owner that (i) borders the Transmission Provider Region; (ii) whose external ties are predominantly to the Transmission System; and (iii) has Seams Operating Agreements that allow for coordinated operations, will be granted ZRCs in the LRZ where their firm transmission service crosses the border of the Transmission Provider Region, and Border External Resources will be granted ZRCs in the LRZ where the Transmission System connects to the substation with its interconnection facilities.

Generation Resources, Intermittent Generation, Electric Storage Resources, and Dispatchable Intermittent Resources will have to meet the terms of Section 69A.3.1.g.

To the extent a Capacity Resource is located on the border of two or more LRZs (e.g., has transmission lines from two or more LRZs terminating at the substation containing the Capacity Resource's interconnection facilities), the Capacity Resource will be assigned to an LRZ as follows:

(i) if the Capacity Resource is located within the MISO BA, MISO will assign that Capacity Resource to the LRZ that contains the Local Balancing Authority in which the Capacity Resource is physically located; or

(ii) if the Capacity Resource is a Border External Resource, MISO will assign that Capacity Resource to the LRZ with which it has the greatest electrical connection. This connection will be determined by the impacts of the Resource on the system, including (i) the electrical loading of transmission facilities within and tying to the Zone and (ii) the transmission constraints which define the CIL and CEL for the Zone.

Once assigned, Capacity Resources which border two or more LRZs will not be reassigned unless significant changes occur in the Transmission Provider Region, including but not limited to, significant changes in LRZ boundaries, membership, the Transmission System, and/or Resources.

b. Participating Demand: All LSEs will be required to meet their Final PRMR through the PRA process, unless they have decided to pay the Capacity Deficiency Charge. LSEs can Self-Schedule ZRCs to meet their PRMR, consistent with the Self-

Scheduling Option in Section 69A.7.8. The Transmission Provider will conduct the PRA based upon the PRMR for the Transmission Provider Region minus the amount of PRMR associated with the Capacity Deficiency Charge, expressed as a variable reliability target through RBDCs for all of the LSEs located within the Transmission Provider Region.

c. Conducting the PRA: The Transmission Provider will conduct the PRA for each Season using the following auction procedures to determine the ACP for each LRZ and ERZ. The PRA shall be designed to commit resources equal to the Final PRMR determined by application of the RBDC for each LSE, minus the amount of PRMR associated with the Capacity Deficiency Charge but including resources used in a FRAP and an RBDC Opt Out, in each LRZ up to the total volume of offered ZRCs. All ZRCs offered at zero price will clear the PRA. The PRA shall clear for each LRZ and ERZ of the Transmission Provider Region. A multi-zone optimization methodology shall be employed to simultaneously perform the following tasks: (1) conduct the PRA to meet the supply and demand balance both for the Transmission Provider Region and for each of the First Planning Area and the Second Planning Area by clearing ZRC Offers and establishing the Final PRMR, as determined by application of the RBDCs, minus the amount of PRMR associated with the Capacity Deficiency Charge for each LRZ of the Transmission Provider Region to yield cleared ZRCs; (2) meet the LCR for each LRZ; (3) efficiently use transmission transfer capability between LRZs and from ERZs; and (4) respect the SREC and SRIC for each SRRZ, if applicable.

(i) **Objective Function:** The objective of the multi-zone optimization methodology shall be to maximize social surplus, using the as-offered overall costs of capacity procurement and the as-bid overall benefits of capacity procurement reflected in the RBDCs over the time horizon, subject to LCR, network constraints, and SRICs and SRECs, if applicable. The overall costs will include the ZRC Offers of all Planning Resources selected for cleared ZRCs. CILs of each LRZ are simultaneous to the extent that imports into the LRZ are concurrently simulated; and CELs of each LRZ and ERZ are simultaneous to the extent that exports out of the relevant LRZ or ERZ are concurrently simulated. Network constraints will be represented by an initial set of zonal CELs and CILs, driven by the dispatch from planning models. The CELs and CILs will be reviewed by the Transmission Provider to determine if there are network loading violations when based on the geographical dispatch derived from the initial auction clearing. If no network violation is indicated, then the auction results are final. If a network violation is indicated, then reductions will be made to the affected export and import capabilities to avoid network violations and the auction will be cleared again with the new set of export and import capabilities. After a maximum of two (2) successive iterations per Season to address network violations, the auction clearing iteration with the fewest megawatts of network violations will be deemed as the final auction result.

(ii) **Time Horizon:** For purposes of clearing the system-wide PRMR the time horizon is an hour, representing the projected maximum Coincident Peak Demand. For a Local Resource Zone, the time horizon is the hour representing the Local Resource Zone Peak Demand, over each Season for the next Planning

Year for the Transmission Provider Region. Coincident Peak Demand is used to establish an LSE's Initial PRMR while Local Resource Zone Peak Demand is used to establish an LRZ's LRR.

(iii) **Capacity Market and Congestion Management:** The multi-zone optimization methodology will perform congestion management simultaneously with the scheduling of capacity for each Season in the Planning Year. Congestion management is the process where ZRCs are cleared to eliminate network constraint violations and to maximize the social surplus of procuring PRMR to meet applicable reliability standards.

(iv) **Model of Transmission Provider Transmission System:** The multi-zone optimization methodology will enforce network constraints represented by CILs, CELs and LCRs that are obtained by using a model of the transmission system including Planning Resources and Demand which will be updated annually to reflect existing and planned transmission and generation projects. Transmission and Planning Resources shall be modeled as part of the multi-zone optimization methodology to reflect their expected state during the peak Hour of each Season in the Transmission Provider Region. The model is of zonal form, which shall include all Planning Resources, Demand, and a representation of systems external to the Transmission Provider Region, and which will be consistent with seams agreements with neighboring regions.

Network Constraints. The multi-zone optimization methodology shall enforce constraints on transmission lines, transformers, and groups of transmission branches that compose transmission interfaces represented by LCR, CIL, and CEL. Most of these constraints shall represent thermal limits on the power flow through transmission facilities. Certain constraints may impose more restrictive limits on power flow, taking into account contingencies and typically represented through operating guides.

Transmission Losses. The multi-zone optimization methodology will clear ZRCs to cover transmission losses; the PRMR will include estimates of transmission losses in its calculation for each Season.

(v) **LRZ ACP Calculation:** The Auction Clearing Price (ACP) for an LRZ is the marginal cost of serving the Demand in that LRZ. The ACP is composed of the system marginal cost of capacity, the regional marginal cost of capacity, the marginal cost of financially binding LCR, CEL, and CIL for a LRZ, (*i.e.*, network constraints that are active at the optimal solution prohibiting a lower cost outcome), and the marginal cost of financially binding SRECs and SRICs for SRRZs, if applicable. The ACP is calculated by considering the next increment or decrement to Demand for each LRZ. The Transmission Provider will calculate ACPs for each LRZ. For accounting purposes, ACP will be expressed in dollars per megawatt-day ($/MW-day).

(vi) **External Resource Zone (ERZ) ACP:** The ACP for an ERZ is comprised of the system marginal cost of capacity, marginal cost of financially binding CEL for the ERZ, the marginal cost of financially binding SRECs and SRICs for SRRZ with which the ERZ interconnects. For ERZs which connect with more than one

SRRZ, or which do not directly connect to a single SRRZ, a weighted average of the marginal cost of financially binding SREC and SRIC will be applied, with weights derived from the distribution of annual energy flows into the SRRZs from the ERZ. For accounting purposes, ACP will be expressed in dollars per megawatt-day ($/MW-day).

(vii) **ACP Inputs:** Primary inputs to the ACP calculation are network constraints represented by CIL, CEL, LCR, and other constraints established by the Transmission Provider associated with SRECs and SRICs for SRRZs in accordance with applicable seams agreements, coordination agreements, or transmission service agreements and the set of valid ZRC Offers and the Final PRMR for the Transmission Provider Region minus the amount of Initial PRMR associated with the Capacity Deficiency Charge for each LRZ. Valid ZRC Offers may include offers from ZRCs converted from confirmed Seasonal Accredited Capacity from Planning Resources. ZRC Offers can be submitted as Self-Schedules, in accordance with Section 69A.7.8.

(viii) **ACP Outputs:** For non-zero ACPs, Resources that set the ACP in a LRZ or ERZ will be cleared in proportion to the amount of ZRCs necessary to meet the Final PRMR. When more than one resource is marginal and offered at the ACP, then all resources offered at the ACP are cleared *pro rata* up to the amount required to meet the reliability requirement. This may result in a portion of multiple Resources clearing as the marginal resources that set the ACP.

(ix) **Eligibility Rules:** ACPs can be set by any ZRC Offers.

(x) **ACP for multiple Seasons with ZRC Shortage Conditions or ZRC Near-Shortage Conditions to meet Local Clearing Requirements:**

When an LRZ has more than one Season in any combination of ZRC Shortage Conditions and/or ZRC Near-Shortage Conditions the final Auction Clearing Price (ACP) for the LRZ will be set as the minimum of: (a) the original ACP as determined in Section 69A.7.1.c.(v) reflecting the effective financial binding of an LCR constraint; or (b) the summation of: (i) the amount composed of the system marginal cost of capacity, the regional marginal cost of capacity, and the marginal cost of financially binding SRECs and SRICs for SRRZs, if applicable; and (ii) the LCR price adder. The LCR price adder will be set as the amount obtained by dividing the applicable LRZ's annual CONE value by the summation of the number of days in Seasons in each Season of the Planning Year in which the LRZ was in ZRC Shortage Conditions in the Planning Resource Auction and the number of days in each Seasons of the Planning Year in which the LRZ was in ZRC Near-Shortage Conditions in the Planning Resource Auction.

(xi) **Notification:** ACPs and total summarized cleared ZRC Offers determined as described above shall be calculated and published by the Transmission Provider by 11:59 pm EST on the twentieth Business Day following the last Business Day in March. The Transmission Provider may extend the publishing deadline based on unanticipated events that: (i) interfered with the Transmission Provider's ability to receive and/or process accurate and complete ZRC Offers or (ii) were otherwise likely to have a widespread negative impact on the results of the PRA. The Transmission Provider shall notify Market Participants and post such notice of any extension of publishing the results of the PRA on its website. The notice shall state the extension's circumstances, rationale, and duration.

Consequences of PRA

All PRA transactions will be financially binding. Market Participants with cleared ZRC Offers must comply with all of the ZRC requirements for all ZRCs that clear in the PRA.

Uncleared ZRCs

Once the PRA has concluded, a Market Participant may convert back to Seasonal Accredited Capacity any ZRCs that do not clear in the PRA.

PRA Reporting

The Transmission Provider will not reveal the ZRC Offers submitted by any Market Participant in a PRA until one (1) month following the completion of the PRA, except as required pursuant to the provisions of Section 38.9 of the Tariff. When the ZRC Offers are posted, price/quantity pairs will be made public, however the names of the Market Participants submitting such offers and the names of the Planning Resources offered shall not be publicly revealed.

Market Monitoring

All actions of Market Participants participating or failing to participate in the PRA shall be subject to the provisions of Module D, except to the extent that a Market Participant has opted out of the PRA as described in Section 69A.9. The Transmission Provider will report any known attempt to exercise market power by LSEs or by Market Participants in the PRA procedures to the Independent Market Monitor.

PRA Settlement

a. Cleared ZRC Offers will be settled at the ACP for the LRZ or ERZ where the ZRC is represented on a daily basis and the Market Participants submitting cleared ZRC Offers will be credited on a weekly basis by the Transmission Provider. The Transmission Provider will settle the LSEs cost of their Final PRMR minus the amount of PRMR associated with the Capacity Deficiency Charge at the ACP for the LRZ where the Demand is located on a daily basis and will debit LSEs weekly, to the extent that an LSE has not opted out of the PRA pursuant to Section 69A.9 or submitted an RBDC Opt Out pursuant to Section 69A.9.1. For LSEs not selecting RBDC Opt Out, the Final PRMR will be established based on the financial binding of RBDCs representing the Transmission Provider Region and applicable planning area (i.e., the First Planning Area or the Second Planning Area).

Final PRMRs will be determined as follows:

i. LSEs using the RBDC Opt Out will have Final PRMRs calculated by multiplying the LSE's forecasted Coincident Peak Demand for each Season, including transmission losses, by (1 + Transmission Provider Region PRM + RBDC Opt Out Adder).

ii. LSEs not using the RBDC Opt Out will have Final PRMRs calculated using the formula below:

$$Final\ PRMR\ for\ a\ LSE\ not\ using\ the\ RBDC\ Opt\ Out$$
$$= \Big(PRA\ Cleared\ Capacity$$
$$- \sum Final\ PRMR\ for\ LSEs\ using\ the\ RBDC\ Opt\ Out\Big)$$
$$\times \frac{Initial\ PRMR\ of\ the\ LSE\ not\ using\ the\ RBDC\ Opt\ Out}{\sum Initial\ PRMR\ of\ all\ LSEs\ not\ using\ the\ RBDC\ Opt\ Out}$$

iii. LSEs under state jurisdiction where the State Regulatory Authority has overridden the PRM established by the Transmission Provider will have Final PRMRs for each Season calculated by multiplying the LSE's forecasted Coincident Peak Demand for each Season, including transmission losses, by (1 + the planning reserve margin established by the State Regulatory Authority).

The Transmission Provider will financially net the ZRC credits and LSE debits for Market Participants. Market Participants with cleared ZRCs sourced from Diversity Contracts will receive reduced credit for any ZRC volumes cleared above their PRMR up to the cleared volume of ZRCs from Diversity Contracts. The reduced compensation will be based on the total number of days the capacity from the Diversity Contract is dedicated to Demand in the Transmission Provider Region in each Season divided by the total number of days in the Season.

b. An LSE that submits a FRAP or an RBDC Opt Out with PRMR in an LRZ and ZRCs in an ERZ or a separate LRZ may be subject to a ZDC, as described below: (i) The Zonal Deliverability Charge will be the maximum of: (a) the difference between the ACP for the LSE's PRMR within an LRZ where an LSE has Demand that is not met by ZRCs from Planning Resources that are represented in such LRZ and the ACP in the LRZ or ERZ where the LSE's ZRCs are represented; or (b) zero. The Transmission Provider will multiply the ZDC by the ZRCs to obtain the deliverability charge that the Transmission Provider will assess the LSE. The Zonal Deliverability Charge will only be assessed to an LSE's Load that is part of a FRAP or for LSEs submitting ZRCs for an RBDC Opt Out.

c. Any portion of an LSE's PRMR not covered by the FRAP, minus the amount of PRMR associated with the Capacity Deficiency Charge, shall be purchased through the PRA. An LSE will be charged the applicable ACP for any PRMR that is not recovered by ZRCs in a FRAP.

d. For instances where a LRZ clears under ZRC Shortage Conditions or ZRC Near-Shortage Conditions to meet Local Clearing Requirement in more than one Season in a Planning Resource Auction and final ACPs are adjusted per Section 69A.7.1.c.(x), certain cleared ZRC Offers may exceed the final ACPs. In this case, such cleared ZRCs may be eligible for a ZRC Offer Revenue Sufficiency Credit, to the extent that settlement amounts credited in paragraph 69A.7.6.a above for a Planning Year are insufficient to cover Allowable ZRC Offer Costs, needed to be incurred by the Planning Resource to be available for cleared Seasons.

ZRC Offer Revenue Sufficiency Credit will be calculated as the greater of: (i) zero; or, (ii) the difference between Allowable ZRC Offer Costs, and the total settlement amounts credited per paragraph 69A.7.6.a for the associated cleared

ZRC Offers for all Seasons in a Planning Year.

Where Allowable ZRC Offer Costs shall equal the minimum of: (i) the sum of all cleared ZRC Offer segment volumes multiplied by the ZRC Offer segment price, multiplied by the number of Days in the Season, calculated for all Seasons for which the ZRCs clear in the Planning Resource Auction; or, (ii) the annual CONE for the LRZ where the ZRCs are represented; or, (iii) the applicable facility-specific Reference Level costs for the Planning Resource, if a Market Participant received a facility-specific Reference Level per Section 64.1.4.

ZRC Offer Revenue Sufficiency Credits will be allocated pro-rata across the Seasons where the ZRC Offer cleared for settlement and distribution.

e. ZRC Offer Revenue Sufficiency Charges will be assessed as the sum of all ZRC Offer Revenue Sufficiency Credits for a Season distributed to Market Participants representing LSEs in an LRZ clearing under ZRC Shortage Conditions or ZRC Near-Shortage Conditions on a pro rata basis, based upon their respective LSE’s share of Final PRMR minus the Initial PRMR associated with the Capacity Deficiency Charge in the appropriate LRZ.

Distribution of Excess Auction Revenue

The following provisions address situations where LSEs will be entitled to receive financial benefits on contractual commitments and/or use of the Transmission System. These benefits will provide LSEs with financial hedges for ACP separation between LRZs and/or ERZs based on excess revenue from the Planning Resource Auction.

The Transmission Provider will distribute any such excess revenues in two stages:

(i) in the first stage, the Transmission Provider shall distribute such excess revenues to LSEs qualifying for Historic Unit Considerations (HUCs) as described in Section 69A.7.7(a) and ZDC Hedges as described in Section 69A.7.7.(b), then

(ii) any remaining excess revenue will be distributed in accordance with the Zonal Deliverability Benefit provisions of Section 69A.7.7(c).

The LSE will only receive excess PRA revenue if the ACP paid by the LSE is higher than the ACP received for such Planning Resources. If there are not sufficient excess revenues to fully fund all Historic Unit Considerations and ZDC Hedges, the revenues will be allocated on a pro rata basis to all HUCs and ZDC Hedges.

Historic Unit Considerations (HUCs)

The Transmission Provider will allocate excess PRA revenue to LSEs with ownership or contractual arrangements, limited to a) Grandfathered Agreements, b) arrangements that predate July 20th, 2011, or c) arrangements that predate March 26, 2018 and pertain to External Resource represented in External Resource Zones in which:

i. The LSE has Initial PRMR obligations equal to or greater than the amount of the Planning Resource designated in the arrangement;

ii. The Planning Resource designated in the arrangement and Initial PRMR obligation span multiple LRZs and/or ERZs;

iii. The LSE has long-term (five years or more) contracts for or ownership of the Planning Resource and has maintained continuous firm Transmission Service or firm Network Resource Interconnection Service, and in the case of External Resources, firm transmission service on the applicable external Balancing Authority transmission system, for that Planning Resource to the LRZ containing the LSE’s associated Initial PRMR obligation; and

iv. LSEs must note qualification for HUCs and submit information supporting HUC eligibility to the Transmission Provider by January 15th prior to the upcoming Planning Year.

A combination of arrangements that require the delivery of capacity throughout the Planning Year will qualify to receive excess PRA revenue through a HUC, provided that the arrangements satisfy the criteria herein. The volume of MW eligible to receive excess PRA revenue will be the lesser of the cleared ZRCs from the Planning Resource(s) or the amount of Initial PRMR that are associated with the qualified arrangement. A qualified arrangement shall remain eligible to receive excess PRA revenue for the current term of the executed contract, excluding any evergreen contract extension, or for two Planning Years, whichever is longer. In the event that the owned resource status is changed to retired, the transmission service is not maintained, or the arrangement is terminated or otherwise expires, the arrangement shall no longer be eligible to receive excess PRA revenue.

ZDC Hedges

An LSE will also be able to receive excess Planning Resource Auction revenue if the LSE qualifies for a ZDC Hedge. A ZDC Hedge can result from approved firm Transmission Service Request where the source and sink are in separate LRZs or between an LRZ and an ERZ that result in required Network Upgrades. The Market Participant that funds the Transmission System upgrades that result in an increase in the CIL, as determined by the Transmission Provider, for an LRZ where the sink is located, will receive a ZDC Hedge. The Market Participant submitting the Transmission Service Request will receive one hundred percent(100%) of the MW volume of the CIL increase. ZDC Hedges will be granted based upon the order that the Transmission Provider receives Transmission Service Requests. Market Participants must submit information supporting ZDC Hedges to the Transmission Provider by November 1st prior to a Planning Year. The volume of a ZDC Hedge will be the incremental increase in the CIL that resulted from the Network Upgrades identified in the approved firm Transmission Service Request. ZDC Hedges will be effective for thirty (30) years or the service life of the Transmission System facility or Network Upgrade, whichever is less.

Zonal Deliverability Benefit

If there are any remaining excess PRA revenues, the Transmission Provider will distribute the remaining amounts to Deliverability Benefit Zones.

First, the Transmission Provider will subtract PRMR and ZRCs associated with HUCs and ZDC Hedges to derive an adjusted PRMR (Adjusted PRMR) and ZRC (Adjusted ZRC). Second, the Transmission Provider shall create a DBZ for each group of LRZs that have equal ACPs which result from the same auction constraint. Third, the Transmission Provider, for each DBZ, will subtract the sum of Adjusted PRMR for each LRZ within the DBZ from the sum of Adjusted ZRCs for each LRZ within the DBZ. A DBZ will be considered a net importing DBZ if the sum of the Adjusted PRMR is greater than the sum of Adjusted ZRCs. A DBZ will be considered a net exporting DBZ if the sum of the Adjusted PRMR is less than the sum of Adjusted ZRCs. A net exporting DBZ shall not receive any ZDB credit. A net importing DBZ shall receive a ZDB credit allocation based upon a weighted average approach. Fourth, the Transmission Provider will calculate the weighted average ACP of all net exporting DBZs (Weighted Average Export ACP) to determine a financial value of export capacity within the Transmission Provider region per the formula below:

$$Weighted\ Average\ Export\ ACP = \frac{\sum(Net\ Export_j \times ACP_j)}{\sum Net\ Export_j}$$

Where j = Each net exporting DBZ

Fifth, the Transmission Provider will calculate the ZDB credit allocation, in dollars, for each net importing DBZ:

$$ZDB\ Credit_k = Net\ Import_k \times (ACP_k - Weighted\ Average\ Export\ ACP)$$

Where k = Each net importing DBZ

Finally, the Transmission Provider will distribute the ZDB credit in each DBZk by dividing the ZDB credit by the sum of Adjusted PRMR of the LRZs within each DBZk. This distribution is a credit to the initial ACP calculated for each LRZ from the PRA.

The Transmission Provider will receive FRAP and RBDC Opt Out related revenue from Zonal Deliverability Charges. The Transmission Provider will allocate such revenue to the DBZ where the PRMR associated with the ZDC is physically located. This revenue will be allocated on a *pro rata* basis by Adjusted PRMR to all LSEs within the DBZ to develop an ACP credit adjustment. The Transmission Provider will also receive FRAP and RBDC Opt Out related revenues derived from ZRCs that would have received payments greater than the charges to the associated FRAP or RBDC Opt Out PRMR. The Transmission Provider will allocate such revenue to the DBZ where the ZRC associated with the FRAP or RBDC Opt Out is represented. This revenue will be allocated on a *pro rata* basis by Adjusted PRMR to all LSEs within the DBZ to develop an ACP credit adjustment. After calculating the ZDB rate(s), if there exists any remaining excess revenue (i.e. surplus), the surplus will be allocated back to the Deliverability Benefiting Zone(s) on a PRMR *pro-rata* basis.

Whenever an LRZ has an ACP that exceeds the System ACP because the LCR for that LRZ exceeds the sum of PRMR for LSEs within that LRZ, payments made to ZRCs in that LRZ will exceed the sum of receipts from LSEs within that LRZ plus any receipts from other LRZs related to such ZRCs. The revenue shortfall within such LRZ will be recovered from all LSEs within that LRZ on a PRMR pro-rata basis. PRMR covered by FRAPs and RBDC Opt Outs will be included in the pro-rata calculation, and the related amounts charged to the LSEs that use FRAPs and RBDC Opt Outs through this Local Clearing Requirement Charge.

Self-Scheduling Option:

LSEs with sufficient ZRCs within an LRZ where the LSE has forecasted Demand will be able to avoid the financial impact of that LRZ's ACP for the Final PRMR by Self-Scheduling such ZRCs into the PRA (*i.e*., by Offering ZRCs into the PRA at a zero price so that the ZRCs will clear). For Planning Resources associated with ZRCs represented outside the LRZ where the LSE has PRMR, an LSE would also need to use the financial hedges described in Section 69A.7.7 to avoid the financial effects of potential price differences between LRZs or between an LRZ and an ERZ.

Installed Capacity (ICAP) Deferral Requirements and Charges

a. ICAP Deferral Notice. Market Participants that request ICAP deferral as provided in Sections 69A.3.1.a.2, 69A.3.1.b.2, 69A.3.1.c.2, and/or 69A.3.6.2. must provide an ICAP Deferral Notice to the Transmission Provider in writing by an officer of the company no later than February 15th prior to the Planning Year: (1) the expected ICAP value (in megawatts) from such Planning Resource and if the Planning Resource is new, the LBA or external BA where it is represented for any Season for which it wants to be eligible to offer ZRCs, (2) appropriate information validating that ICAP will be submitted to the Transmission Provider by the last business day of the Month prior to the start of any Season in which it wants to be eligible.

b. ICAP Deferral Credit Requirements. A Market Participant that provides ICAP Deferral Notice must satisfy credit requirements by March 1st prior to the Planning Year totaling the ICAP value provided in the ICAP Deferral Notice, multiplied by ninety (90) days of daily CONE values (i.e., 90/365 times CONE) for the LRZ where the Planning Resource is represented. If the Planning Resource is represented in an ERZ connected to a single SRRZ, the applicable CONE value will be the greatest CONE value of all LRZs in respective SRRZ. For External Resources represented in ERZs which are connected to multiple SRRZs, or which are not directly connected to any SRRZs, the applicable CONE value will be the greatest CONE value of all LRZs in those connected SRRZs. If the Market Participant: (1) submits GVTC results, demonstrates deliverability, and demonstrates commercial operation, or (2) registers replacement ZRCs in accordance with Section 69A.3.1.h, then the Transmission Provider will adjust the Market

Participant's credit requirement to account for these changes within ten (10) Business Days after ICAP is submitted or replacement ZRCs have been provided to the Transmission Provider. In the event ZRCs associated with a Planning Resource for which ICAP has been deferred are unconverted in accordance with 69A.7.3, the Market Participant may provide notice to the Transmission Provider that it wishes to forfeit the deferred ICAP value. Then the Transmission Provider will adjust the Market Participant's ICAP value and credit requirement within ten (10) Business Days.

c. ICAP Deferral Non-Compliance Charges.

i. A Market Participant that provides ICAP Deferral Notice and that either (1) has not submitted ICAP for such Planning Resources by the last business day of the Month prior to the start of any Season for which it has deferred, or (2) has submitted an ICAP value demonstrating fewer megawatts are available than the ICAP value submitted in the ICAP Deferral Notice, shall be assessed ICAP Deferral Non-Compliance Charges unless it completes ZRC replacement in accordance with Section 69A.3.1.h. Assessment of ICAP Deferral Non-Compliance Charges will commence on the first day of the any Season for which a Market Participant has an ICAP deferral and continue until ICAP is submitted and verified by the Transmission Provider, replacement ZRCs are registered per the BPM for Resource Adequacy, the ICAP value is forfeited, or the end of any deferred Season, whichever is earlier. Market Participants with Planning Resources subject to ICAP Deferral Non-Compliance Charges do not have to meet the applicable performance requirement as described in Sections 69A.3.9

and 69A.5 for such Resources, until such time that they are no longer subject to these charges.

ii. ICAP Deferral Non-Compliance Charges will be calculated as follows: the amount of ICAP that has not been submitted to the Transmission Provider multiplied by the sum of the ACP and the daily CONE value (i.e., 1/365 times CONE). The ACP and the CONE values will be based on the LRZ where the Planning Resource is represented. If the Planning Resource is represented in an ERZ connected to a single SRRZ, the applicable CONE value will be the greatest CONE value of all LRZs in respective SRRZ. For External Resources represented in ERZs which are connected to multiple SRRZs or which are not connected to any SRRZs, the applicable CONE value will be the greatest CONE value of all LRZs in those connected SRRZs.

iii. Distribution of ICAP Deferral Non-Compliance Charges: ICAP Deferral Non-Compliance Charge revenues received by the Transmission Provider will be distributed to Market Participants representing LSEs on a *pro rata* basis, based upon the LSE's share of Final PRMR minus the Initial PRMR associated with the Capacity Deficiency Charge for the Transmission Provider Region during the applicable Season.

Calculation of CONE and Net CONE

a. The CONE value shall initially be the rate proposed by the Transmission Provider in a 2012 Federal Energy Regulatory Commission filing and approved by the Commission for the Planning Year commencing on June 1, 2013. The Transmission Provider and the IMM shall consider factors, including, but not limited to: (1) physical factors (such as, the type of Generation Resource that could reasonably be constructed to provide Planning Resources, costs associated with locating the Generation Resource within the Transmission Provider Region, the estimated costs of fuel for the Generation Resource); (2) financial factors (such as, the hypothetical debt/equity ratio for the Generation Resource, the cost of capital, a reasonable return on equity, applicable taxes, interest, insurance); and (3) other costs (such as, costs related to permitting, environmental compliance, operating and maintenance expenses). In calculating the CONE, the Transmission Provider and the IMM shall not consider the anticipated net revenue from the sale of capacity, Energy or Ancillary Services. CONE values will be calculated for each LRZ. The Transmission Provider shall arrange for CONE values to be calculated in concert with the IMM no later than September 1 beginning on September 1, 2012. The recalculated CONE values shall be filed with the Commission annually thereafter.

b. The Transmission Provider shall calculate Net CONE values for each LRZ. Net CONE represents the difference between CONE values and Inframarginal Rents, for the Generation Resource type used in the CONE value calculation (the Reference Resource Type) . The following process will be used to estimate Net CONE:

To determine Inframarginal Rents, the most recent three Planning Years of historic data will be compiled for each Generation Resource of the Reference Resource Type operating in the Transmission Provider Region consisting of all revenues for the Generation Resource from the Transmission Provider's Energy and Operating Reserve Markets, on a per MW or MWh basis, whichever is applicable, calculated hourly, and Production Costs calculated hourly. The greater of the market revenues minus Production Costs, or zero, shall be calculated hourly, and summed across all Hours for each Planning Year, for each resource of the Reference Resource Type. Inframarginal Rents outside of two standard deviations from the sample mean are removed. The Generation Resources are then grouped into LRZs based on their location. An average Inframarginal Rents is calculated for each LRZ and then scaled using a capacity factor for each LRZ. The capacity factor is the ratio of the commitment hours of the Generation Resource of the Reference Resource Type that is committed for the maximum number of hours in the Planning Year amongst all Generation Resources of the Reference Resource Type to the average commitment hours of all Generation Resources of the Reference Resource Type that were committed in the LRZ in the Planning Year. This results in Inframarginal Rents values for each LRZ for each Planning Year, which will be averaged over a three-year period to determine an initial Inframarginal Rents for each LRZ.

To determine the final Inframarginal Rents values to be used for the upcoming Planning Year, the Transmission Provider will apply a scaling factor to the initial Inframarginal Rents. The scaling factor will be based on statistical models between: a) LMPs to gas, and; b) LMPs to Inframarginal Rents. Readily available settled futures gas prices for the upcoming Planning Year will be applied to the statistical models to calculate the scaling factor.

Each LRZ's final Inframarginal Rents are then grouped and averaged into values in the First Planning Area and Second Planning Area. The values from the First Planning Area and Second Planning Area are then subtracted from the LRZ-specific CONE values to get an estimate of Net CONE for each LRZ. For use in the PRA, Net CONE values are sorted into values in the First Planning Area and Second Planning Area.

The Transmission Provider shall arrange for Net CONE values to be calculated no later than September 1 prior to the subsequent Planning Year beginning on September 1, 2024. The recalculated Net CONE values shall be filed with the Commission annually thereafter.

Use of FRAP in the Planning Resource Auction

An LSE electing to use a Fixed Resource Adequacy Plan (FRAP) in the PRA for any Season can continue to use its existing resource planning processes to meet all or any portion of its Initial PRMR by providing the Transmission Provider with a FRAP, as described below:

a. An LSE electing to use a FRAP for any Season must submit a FRAP for each LRZ to the Transmission Provider by the 7th Business Day of March prior to a Planning Year in order for the LSE to demonstrate that the LSE has designated ZRCs in order to meet all or any portion of the LSE's Initial PRMR for such LRZ. Market Participants submitting registrations for new and existing Load Modifying Resources can be included in the Module E Capacity Tracking Tool beginning as early as December prior to the Planning Year. Load Modifying Resources registrations submitted to the Transmission Provider will be evaluated to determine if Load Modifying Resources meet the qualification requirements. Market Participants that submit registrations by February 1 prior to the Planning Year will be evaluated by the Transmission Provider and will be notified of the outcome on or before February 21 that precedes the Planning Year.

Market Participants that submit registrations between February 2 and February 15 prior to the Planning Year will be evaluated by the Transmission Provider and will be notified of the outcome at least two Business Days prior to the FRAP deadline. The Transmission Provider will make a good faith effort to notify Market Participants that submit registrations after February 15 but not later than March 1 of the outcomes of such registrations no later than the FRAP deadline. The FRAP must include the LSE's forecasted Coincident Peak Demand for each LRZ for each Season and also identify the

ZRCs that the LSE owns, or has contractual rights to, in order to provide Planning Resources to meet the FRAP designated portion of its Initial PRMR and also its load ratio share of the LCR for each LRZ for each Season. The Transmission Provider will evaluate each LSE's FRAP to determine if it meets the designated portion of the LSE's Initial PRMR and the LSE's share of LCR and the Transmission Provider will notify the LSE via the MECT prior to March 15th before a Planning Year of the extent that the portion of an LSE's Initial PRMR or share of LCR for each LRZ is not covered by a submitted FRAP. The LSE will have until the PRA offer window opens to remedy any deficiencies in their FRAP for each Season.

b. To the extent that the LSE's ZRCs satisfy the portion of the LSE's Initial PRMR for the applicable Season(s) submitted through a FRAP, (1) the LSE will not have an obligation to make ZRC Offers for the ZRCs included in the FRAP into the PRA, or otherwise participate in the PRA for such Season; and (2) the LSE will not have an obligation to pay the applicable ACP for the LSE's Initial PRMR within such LRZ that is covered by the FRAP. The Transmission Provider will consider all PRMR and ZRCs, including PRMR and ZRCs in FRAPs, as part of the Transmission Provider's reliability assessment when conducting the PRA.

c. Any portion of an LSE's Initial PRMR not covered by the FRAP may be purchased through the PRA. An LSE will be charged the applicable ACP for any PRMR that is procured through the PRA.

d. If an LSE owns or controls ZRCs that are not included in the LSE's FRAP, then such LSE may submit ZRC Offers into the PRA for all such excess ZRCs, subject to Module D.

e. To the extent that an LSE designates ZRCs in a FRAP that are represented in the same LRZ as the LSE's Demand to meet the LSE's Initial PRMR for such LRZ, then the LSE will not be subject to a Zonal Deliverability Charge for such ZRCs.

f. An LSE that contains ZRCs from Planning Resources that are not represented in the same LRZ where the LSE has Demand may be subject to a Zonal Deliverability Charge, which will be calculated as described in Section 69A.7.6(b).

Use of RBDC Opt Out in the Planning Resource Auction

An LSE electing to use the RBDC Opt Out can continue to use its existing resource planning processes to meet its Final PRMR by providing the Transmission Provider with an RBDC Opt Out, as described below:

a. The RBDC Opt Out Lock-In Period will be three consecutive Planning Years for all Seasons. If an LSE fails to submit an RBDC Opt Out then the LSE will be required to participate in the PRA through any combination of the other Tariff-defined options, or pay the Capacity Deficiency Charge, for each Planning Year in which the LSE does not submit an RBDC Opt Out.

b. An LSE under state jurisdiction where the State Regulatory Authority has overridden the PRM established by the Transmission Provider is not eligible to select the RBDC Opt Out.

c. An LSE selecting the RBDC Opt Out will be required to meet its Final PRMR for the entirety of its load and losses, and its entire share of LCR for each LRZ, for each Season.

d. An LSE must provide an initial notification of its intent to elect the RBDC Opt Out no later than January 15th prior to the upcoming Planning Year. An LSE electing the RBDC Opt Out must submit its final plan for each LRZ to the Transmission Provider by the 7th Business Day of March prior to each Planning Year during the RBDC Opt Out Lock-In Period in order for the LSE to demonstrate that the LSE has designated ZRCs in order to meet the LSE's Final PRMR, and share of LCR for each LRZ, for each Season. Market Participants using the RBDC Opt Out must submit all registrations for new and existing resources to be used in the RBDC Opt Out through the MECT consistent with the timelines established in the Business Practices Manual for Resource Adequacy. The RBDC Opt Out must include the LSE's seasonal forecasted Coincident Peak Demand for each LRZ and also identify the ZRCs that the LSE owns, or has contractual rights to, in order to provide Planning Resources to meet its Final PRMR, and also its share of the LCR for each LRZ for each Season. The Transmission Provider will evaluate each LSE's RBDC Opt Out on an annual basis to determine if it meets the LSE's Final PRMR and the LSE's share of LCR requirements for all Seasons. The Transmission Provider will notify the LSE prior to March 15th before the applicable Planning Year whether the submitted RBDC Opt Out meets the LSE's Final PRMR, and share of LCR for each LRZ, requirement for each Season during the applicable Planning Year. The LSE must remedy any deficiencies in its RBDC Opt Out for each Season before the PRA offer window opens.

e. The Transmission Provider will notify the RERRA(s) following the submission of an initial intent to elect the RBDC Opt Out by an LSE. RERRA(s) may elect to notify the Transmission Provider within twenty (20) Business Days whether the LSE's load subject to the RERRA's respective jurisdiction is authorized to select the RBDC Opt Out. Upon receipt of such a notification from the RERRA(s) that the LSE is not authorized to elect the RBDC Opt Out for the LSE's load subject to the RERRA's respective jurisdiction, the Transmission Provider will reject the

LSE's RBDC Opt Out for such load. If the Transmission Provider receives no notification from the RERRA(s) within the twenty (20) Business Day period, and an LSE has demonstrated that it has designated ZRCs in order to meet its Final PRMR, and share of LCR for each LRZ, for each Season, then the proposed RBDC Opt Out by the LSE will be deemed accepted by the Transmission Provider.

f. To the extent that the LSE's ZRCs satisfy the LSE's Final PRMR for the applicable Season(s) submitted through an RBDC Opt Out, (1) the LSE will not have an obligation to make ZRC Offers for the ZRCs included in the RBDC Opt Out into the PRA, or otherwise participate in the PRA for such Season; and (2) the LSE will not have an obligation to pay the applicable ACP for the LSE's Final PRMR within such LRZ. The Transmission Provider will consider all PRMR and ZRCs, including PRMR and ZRCs in RBDC Opt Outs, as part of the Transmission Provider's reliability assessment when conducting the PRA.

g. If an LSE owns or controls ZRCs that are not included in the LSE's RBDC Opt Out, then such LSE may submit ZRC Offers into the PRA for all such excess ZRCs, subject to Module D.

h. To the extent that an LSE designates ZRCs in an RBDC Opt Out that are represented in the same LRZ as the LSE's Demand to meet the LSE's Final PRMR for such LRZ, then the LSE will not be subject to a Zonal Deliverability Charge for such ZRCs.

i. An LSE that designates ZRCs from Planning Resources that are not represented in the same LRZ where the LSE has Demand may be subject to a Zonal Deliverability Charge, which will be calculated as described in Section 69A.7.6(b).

j. LSEs that submit an RBDC Opt Out may not use any of the other options to satisfy their Final PRMR including: (i) submitting a Fixed Resource Adequacy Plan; (ii) Self-Scheduling ZRCs; (iii) purchasing ZRCs through the Planning Resource Auction process, and/or (iv) paying the Capacity Deficiency Charge to meet all or a portion of their Initial PRMR.

k. LSEs that elect the RBDC Opt Out that do not meet their Final PRMR shall pay the RBDC Opt Out Deficiency Charge, which is 2.748 times applicable LRZ's CONE multiplied by the difference in ZRCs between the LSEs Final PRMR and the amount of ZRCs submitted as the LSEs RBDC Opt Out for each Season in which the LSE fails to meet its Final PRMR.

l. RBDC Opt Out Deficiency Charge revenues will be distributed to Market Participants representing LSEs on a pro rata basis, based upon their respective LSE's share of Final PRMR for the Transmission Provider Region minus the Final PRMR associated with the RBDC Opt Out Deficiency Charge. If the LRZ where LSEs incurred RBDC Opt Out Deficiency Charges failed to meet its Local Clearing Requirement ("LCR"), then RBDC Opt Out Deficiency Charge revenues will be distributed to Market Participants representing LSEs on a pro rata basis, based upon their respective LSE's share of Final PRMR minus the Final PRMR associated with the RBDC Opt Out Deficiency Charge in such LRZ.

m. The Transmission Provider will determine the RBDC Opt Out Adder that will be applicable for the upcoming Planning Year every year on or before December 15. The RBDC Adder applicable during the first Planning Year in which an LSE elects to use the RBDC Opt Out will apply for such LSE's entire RBDC Opt Out Lock-In Period.

n. The Transmission Provider will determine the RBDC Opt Out Adder based on a Seasonal average of the RBDC based PRA clearing for the prior three Planning Years. If the prior year RBDC based PRA clearing is not available, simulated RBDC based PRA clearing will be used to determine the RBDC Opt Out Adder.

Capacity Deficiency Charge

a. The Transmission Provider will impose a Capacity Deficiency Charge on an LSE that has provided notification prior to the Planning Resource Auction that they will meet their Initial PRMR in part or in whole by removing Initial PRMR from the Transmission Provider's capacity construct for one or more Seasons by paying the Capacity Deficiency Charge. The Capacity Deficiency Charge will be calculated as follows: The CONE value for the LRZ(s) where the LSE has provided notice it will be meeting its Initial PRMR by paying the Capacity Deficiency Charge for each Season of the Planning Year will be multiplied by 2.748 times the Initial PRMR volume indicated by the LSE. The Capacity Deficiency Charge will be assessed to Market Participants representing their respective LSE paying the Capacity Deficiency Charge on the first Business Day after the results of the Planning Resource Auction have been published.

b. Distribution of Capacity Deficiency Charge Revenues: A Market Participant representing an LSE that provided notice it will be meeting all or part of its Initial PRMR by paying the Capacity Deficiency Charge will not be distributed any Capacity Deficiency Charge revenues for that LSE's Initial PRMR that was met by paying the Capacity Deficiency Charge. Capacity Deficiency Charge revenues received by the Transmission Provider will be distributed to Market Participants representing LSEs on a *pro rata* basis, based upon their respective LSE's share of Initial PRMR for the Transmission Provider Region minus the Initial PRMR associated with the Capacity Deficiency Charge. If the LRZ where LSEs incurred Capacity Deficiency Charges failed to meet its Local Clearing Requirement ("LCR"), then Capacity Deficiency Charge revenues will be distributed to Market Participants representing LSEs on a *pro rata* basis, based upon their respective LSE's share of Initial PRMR minus the Initial PRMR associated with the Capacity Deficiency Charge in such LRZ.

BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c) Emergency Order: Midcontinent Independent System Operator and Northern Indiana Public Service Company LLC	)))))	Order No. 202-26-19
Federal Power Act Section 202(c) Emergency Order: Midcontinent Independent System Operator and CenterPoint Energy Indiana South	))))	Order No. 202-26-20

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

Exhibit 60
MISO Tariff Section 38.2.7

38.2.7 Generation Suspension, Generation Retirement, and System Support Resources

a. Generator or SCU Notification of Change in Status.

(i) Notification Procedures for Units.

An owner of a Generation Resource, Synchronous Condenser Unit (SCU), or a Generator that is directly interconnected to the Transmission System but is Pseudo-tied out of the Transmission Provider's Balancing Authority Area that is planning to Suspend operations of all or any portion of that resource must notify the Transmission Provider of such a plan by submitting a completed Attachment Y Notice to the Transmission Provider. This notification provision also applies to a Generation Resource connected to the underlying lower voltage facilities within Transmission Provider region and to Generation Resources that are not directly interconnected to the Transmission System, but are External Resources that are Pseudo-tied into the Transmission Provider's Balancing Authority Area. The Transmission Provider shall coordinate with the entity to which the External Resource is directly connected to determine whether the External Resource is necessary for reliability of the Transmission System, in accordance with applicable coordinated planning provisions between the Transmission Provider and the regional planning entity to which the External Resource is interconnected.

The owner of a Generation Resource or SCU shall submit an Attachment Y Notice to the Transmission Provider at least four full Quarterly Study Periods prior to changing to Suspend status, unless the Generation Resource or SCU is inoperable due to Forced Outage in which case Attachment Y Notice must be submitted to the Transmission Provider at least thirty (30) days prior to changing to Suspend status. A Generation Resource that has undergone a Reliability Assessment Study that performs an Attachment Y equivalent study as part of the Generating

Facility Replacement process and all reliability violations identified through such study have been mitigated must submit an Attachment Y Notice to the Transmission Provider at least thirty (30) days prior to changing to Suspend status. The owner of a Pseudo-tied out Generator shall submit an Attachment Y Notice to the Transmission Provider at least thirty (30) days prior to the anticipated effective date of change of status.

A Generation Resource or SCU that is inoperable due to Forced Outage or a Pseudo-tied out Generator shall not be designated as an SSR Unit. The provisions for time limitations on suspension within Section 38.2.7 shall apply to a Generation Resource or SCU that is inoperable due to Forced Outage and a Pseudo-tied out Generator.

A Generation Resource that is designated as a Blackstart Unit by a Transmission Operator in its System Restoration Plans shall not be designated as an SSR Unit to solely provide Blackstart Service. However, the Transmission Provider may determine that SSR Unit status is justified if such Generation Resource is required to maintain the reliability of the Transmission System based on its Attachment Y Reliability Study. Section 38.2.7 shall not modify or alter a Transmission Operator's obligations under the Tariff to identify Blackstart Units that are included in its System Restoration Plans, or a Blackstart Unit Owner's obligations to comply with the terms of any Blackstart Service agreement, in accordance with Schedule 33, or the requirements of Commission approved reliability standards.

The following exception applies to the Generation Suspension, Generation Retirement and System Support Resource (SSR) provisions in Section 38.2.7: The owner of a Generation Resource or SCU that requests a Generator Planned Outage or submits a Generator Forced Outage through the Transmission Provider's outage scheduling system (Control Room

Operations Window – CROW or its successor) does not need to submit an Attachment Y Notice to the Transmission Provider if the request does not involve a change of status to Suspend.

An owner of a Generation Resource, SCU, or a Pseudo-tied out Generator certifies by submitting an Attachment Y Notice that it has elected to Suspend such resource and the Attachment Y Notice shall be executed by an officer of such owner attesting to that claim. The decision to Suspend may be modified by rescission as specifically provided in this Section 38.2.7.

An owner may not submit a new Attachment Y Notice to Suspend that supersedes a prior notification unless the prior Attachment Y Notice is rescinded. The new Attachment Y Notice shall be submitted to the Transmission Provider at least four full Quarterly Study Periods prior to changing to Suspend status.

(ii) Confidentiality of Attachment Y Notice.

The Transmission Provider shall treat all Attachment Y Notices as Confidential Information unless the Attachment Y Reliability Study is complete and any of the following occurs: 1) the owner has elected to waive its rescission rights; 2) the resource fails to return to operation before the period for rescission has lapsed; 3) public release is required under Section 38.2.7.b in order to evaluate the need for an SSR Agreement; or 4) the information is otherwise publicly disclosed by the owner of a Generation Resource, SCU, or a Pseudo-tied out Generator. The Transmission Provider shall promptly post on OASIS that an Attachment Y Notice was submitted, along with the effective date of retirement, under the first three of these circumstances.

(iii) Notification of the Outage Scheduler After Submittal of Attachment Y Notice.

After receipt of an Attachment Y Notice, the Transmission Provider shall schedule such outage notification through the Transmission Provider's Control Room Operations Window ("CROW") outage scheduling system, or successor system, to coordinate the outage planning of a Generation Resource or SCU through CROW, on behalf of the owner.

b. SSR Unit Procedures.

System Support Resource (SSR) procedures provide a mechanism for the Transmission Provider to enter into agreements with Market Participants that own or operate Generation Resources or Synchronous Condenser Units (SCUs) that are required by the Transmission Provider to maintain reliability of the Transmission System, if all or a specified portion of the capacity of such Generation Resources or SCUs would otherwise either Retire or Suspend. SSR Agreements are a last-resort measure to address a reliability issue on the Transmission System facilities under the functional control of the Transmission Provider and shall only be entered into once all potential SSR Agreement alternatives have been examined.

An owner of a Generation Resource or SCU must submit all necessary information to enable the Transmission Provider to evaluate whether SSR Unit status is appropriate for such Generation Resource or SCU. If, after completing a reliability study (Attachment Y Reliability Study) and analyzing potential alternatives (Attachment Y Alternatives Study), the Transmission Provider determines that SSR Unit status is justified for a Generation Resource or SCU, that is not subject to an exception under Section 38.2.7.a, then the Transmission Provider and Market Participant of such Generation Resource or SCU shall enter into an SSR Agreement, in accordance with the Attachment Y-1 form of agreement. The SSR Unit will be operated in accordance with the terms of the SSR Agreement, which contains detailed terms and conditions regarding operation and compensation of such Generation Resource or SCU. The Transmission Provider shall periodically review the reliability requirements of the Transmission Provider Region and shall determine which, if any, SSR Agreements should be extended.

The Transmission Provider shall use reasonable efforts to respond to the owner within 150 Calendar Days after the start of the individual Attachment Y Reliability Study, regarding whether the subject of an Attachment Y Notice appears to be required for transmission system reliability, unless an alternative date is agreed to by the owner and the Transmission Provider.

If the Attachment Y Reliability Study determines that a reliability concern exists, and a response is provided by the Transmission Provider to the owner, the Transmission Provider shall promptly post on OASIS: (1) that an Attachment Y Notice was submitted; (2) that the Transmission Provider's Attachment Y Reliability Study concluded that the Generation Resource or SCU was required for the reliability of the Transmission System; (3) the draft report on the Attachment Y Reliability Study with the CEII information redacted from the report; and (4) how the associated SSR Unit costs would be allocated in the event that the Generation Resource or SCU is required to provide service under an SSR designation.

The Transmission Provider shall discontinue Confidential treatment of an Attachment Y Notice and Attachment Y Reliability Study in the event that the Attachment Y Reliability Study results determine that the Generation Resource or SCU is required to maintain system reliability and would be eligible for treatment as an SSR Unit. The Transmission Provider may use information related to Retire or Suspend status in its Transmission Planning processes (pursuant to Attachment FF and the Transmission Planning BPM) and in its Generator Interconnection process (pursuant to Attachment X and the Generation Interconnection BPM), provided that recipients of the information have signed appropriate Non-Disclosure Agreements with the Transmission Provider.

c. Evaluation of Need for the SSR Designation.

The Transmission Provider will perform an Attachment Y Reliability Study to determine whether the Generation Resource or SCU is necessary for the reliability of the Transmission System based on the analyses described in this section and the criteria set forth in the Business Practices Manuals, but will not determine in this initial analysis the available alternatives to designating the Generation Resource or SCU as an SSR Unit. The Transmission Provider will start the study process at the beginning of the Quarterly Study Period. A request to Suspend operations submitted in an Attachment Y Notice received during a quarter will be studied individually, beginning in the subsequent Quarterly Study Period.

In collaboration with the affected Transmission Owners, the Transmission Provider will cause an evaluation to be performed of transmission system conditions (an Attachment Y Reliability Study) that result from the change in status of the unit(s) subject to Attachment Y notification requirements. The evaluation will consider the performance of the transmission system to determine if thermal or voltage violations of applicable NERC Standards and Transmission Owner planning criteria occur when the unit is offline compared to conditions when the unit is online. The scope of this evaluation will include a steady state analysis, and may require analyses of stability and import limitations for the particular study area. Study cases will be derived from approved MTEP models that are representative of the period of time for which the suspension of the unit(s) is requested, and will include models that represent near-term and/or longer-term scenarios as appropriate for the study period. Models that are developed to reflect both the online and offline status of the unit being evaluated will be analyzed to compare the differences in results to determine the impact of the unit on the transmission system. The results of the evaluation will be reviewed with the participating Transmission Owners to verify the Transmission Provider's findings and to evaluate proposed solutions that should be considered to address the reliability issues. The need to retain a unit(s) as a System Support Resource, absent implementation of a feasible alternative, shall be determined by the presence of unresolved reliability violations on the Transmission System that is under the functional control of the Transmission Provider.

The Transmission Provider shall post the determination of reliability need on the Transmission Provider's OASIS and shall: (1) begin negotiations of a potential SSR Agreement with the Market Participant owning or operating the Generation Resource or SCU; and (2) use reasonable efforts to hold a stakeholder meeting pursuant to Attachment FF within thirty (30) Calendar Days to review alternatives to the potential SSR Unit designation or designations (if multiple Attachment Y Notices apply). The Transmission Provider will schedule subsequent stakeholder meetings as needed. The Transmission Provider shall complete the Attachment Y Alternatives Study within four full Quarterly Study Periods after receipt of an Attachment Y Notice, if the Attachment Y Notice provides only four full Quarterly Study Periods of advance notification, unless otherwise agreed to by the owner of the potential SSR Unit. If no alternative is identified as available by the Attachment Y Notice date to Suspend, then the Transmission

Provider shall file the SSR Agreement with an effective date as of the Attachment Y Notice date to Suspend.

Before entering into an SSR Agreement with any Generation Resource or SCU, the Transmission Provider shall assess, in an open and transparent planning process in accordance with the provisions of the Transmission Expansion Planning Protocol Attachment FF to the Tariff, feasible alternatives to the proposed SSR Agreement. The list of alternatives to SSR Unit status that the Transmission Provider shall consider and expeditiously approve as applicable include (depending upon the type of reliability concern identified): (i) redispatch/reconfiguration through operator instruction; (ii) remedial action plans; (iii) special protection schemes initiated upon Generation Resource trips or unplanned Transmission Outages; (iv) contracted demand response or Generator alternatives; and (v) transmission expansions. Consistent with Section B.1.b of Attachment FF, the Transmission Provider will review and evaluate alternatives to an SSR Agreement on a comparable basis and select the most appropriate solution. Comparability includes the ability of the Transmission Provider to require contractual assurances that the party who provides the alternative solution will implement the solution before the Generation Resource or SCU with the Attachment Y Notice is permitted to Retire or Suspend. The executed contractual arrangements must provide a binding arrangement that obligates the Market Participant who provides the alternative solution to complete any required infrastructure changes that are needed to avoid the reliability issues that would otherwise be addressed by transmission upgrades. While the contractual arrangements will vary based on the particular solution, the terms of the contractual arrangements must further obligate the party who provides the alternative solution to implement actions when required by the Transmission Provider to provide necessary relief. A Generator alternative may be a new Generator, an existing Generator that is made available after the Attachment Y Reliability Study is completed, or an increase to existing Generator capacity that has an executed Generator Interconnection Agreement pursuant to Attachment X for a Commercial Operation Date that is prior to the commencement of the change of status date of the Generation Resource or SCU that has submitted an Attachment Y Notice and must be registered as a Generation Resource that is obligated to offer into the market and respond to instructions from the Transmission Provider. Contractual commitments associated with demand-side resource alternative solutions shall require demonstration to the Transmission Provider of an executed contract between LSE or ARC and Energy Consumers as well as necessary procedures and protocols for responding to Transmission Provider instructions. Such demand-side contracts must be in place by the time that the SSR Agreement alternative solution would otherwise need to be committed in order to ensure a timely solution to the identified planning need, and must be of a sufficient duration such that a reliable alternative solution can be assured. In assessing applicability for SSR status, the Transmission Provider will not require continued operation when the continued operation of a portion or all of Generation Resources or SCUs would be contrary to applicable law, regulations, or court or agency orders (such as a settlement with an environmental agency or a consent decree approved by a court). In performing the Attachment Y Reliability Study and the Attachment Y Alternatives Study to an SSR Agreement, the Transmission Provider shall collaborate with the affected Transmission Owners and NERC-registered Transmission Planners, and if appropriate, may consult with a retained consultant. The Transmission Provider will appropriately identify any Confidential Information regarding a decision to Suspend before the Transmission Provider transfers such information to any entity. An entity that receives Confidential Information must agree in writing to maintain such confidentiality, to comply with any confidentiality obligations owed to Transmission Provider under the Tariff or pursuant to a related non-disclosure agreement, and to comply with applicable Standards of Conduct found in 18 C.F.R. § 358. The owner of the Generation Resource or SCU subject to review under this section shall make good faith efforts to minimize the costs to be incurred by seeking any available waivers or exemptions from environmental or other regulatory requirements that would necessitate improvements to the potential SSR Unit. The Transmission Provider will reasonably assist the owner of a potential SSR Unit in working with regulatory agencies to obtain environmental or other waivers or exemptions to the extent necessary to maintain the reliability of the Transmission System. For purposes of determining whether a Generation Resource or SCU qualifies as an SSR Unit, the Transmission Provider will process multiple Attachment Y Notices in the order in which the Attachment Y Notices are received. If a subsequent Attachment Y Notice is received before a determination is made for a Generation Resource or SCU that is the subject of a prior Attachment Y Notice, the Generation Resource or SCU that is the subject of a prior Attachment Y Notice will not be the subject of an SSR Agreement to avoid reliability issues caused by the subsequently noticed suspension of another Generation Resource or SCU.

The filing of a SSR Agreement with FERC shall be accompanied by a corresponding report on the Attachment Y Reliability Study and the Attachment Y Alternatives Study that details the methodologies used, study assumptions, Transmission Owner planning criteria used (including when the criteria became effective and the approving regulatory body, if any), analysis results, an evaluation of alternatives and the conclusion of the study (including a short explanation of the proposed solution to any reliability issue identified and estimated timetables for implementing the preferred solution). An affirmation that the results, in whole or in part, from a previously filed report remain applicable may substitute for filing an entirely new report on the Attachment Y Reliability Study and the Attachment Y Alternatives Study.

d. Modification or Rescission of an Attachment Y Notice.

(i) Rescission of an Attachment Y Notice Prior to the Transmission Provider's Reliability Study Response.

The Transmission Provider shall notify the owner prior to publicizing the Attachment Y Notice and Attachment Y Reliability Study results that the Attachment Y Reliability Study is complete. However, the Transmission Provider shall not provide any information related to the Attachment Y Reliability Study results to the owner at that time. The owner may rescind its Attachment Y Notice by submitting an amended Attachment Y Notice to the Transmission Provider stating its intention, not more than fifteen (15) Business Days after receiving notice from the Transmission Provider that the Attachment Y Reliability Study is complete. In the event of such rescission, the confidentiality of the Attachment Y Notice shall be preserved.

(ii) Modification or Rescission of an Attachment Y Notice After the Owner of Generation Resource or SCU Receives the Results of Attachment Y Reliability Study, but Prior to Commencing Suspension, Retirement, or an SSR Agreement.

(1) An owner of a Generation Resource or SCU that notifies the Transmission Provider in writing of a decision to Suspend, and for which the Transmission Provider has determined that the Generation Resource or SCU is not necessary for the reliability of the

Transmission System, may rescind its decision to Suspend any time prior to the end of the period for rescission following the effective date or may modify the start of the suspension any time prior to the original effective date by submitting an amended Attachment Y Notice to the Transmission Provider stating its intention. If the revised date for suspension is prior to the original date specified in the Attachment Y Notice, a new Attachment Y Notice shall be submitted to the Transmission Provider at least four full Quarterly Study Periods prior to the effective date of suspension.

At any time during the Attachment Y Conversion Period, the owner of the Generation Resource or SCU for which the Transmission Provider has determined is not necessary for the reliability of the Transmission System, may elect to convert the Attachment Y Notice to retirement by notifying the Transmission Provider of its intent to waive the right to both rescind and modify the Attachment Y Notice. After the owner has waived the right to both rescind and modify the Attachment Y Notice, the requested status of the Generation Resource will change to Retire, and the interconnection service will be terminated in accordance with Section 38.2.7.k. The Attachment Y Notice will no longer be treated as Confidential Information once the owner has elected to waive its right to both rescind and modify the Attachment Y Notice and committed to retirement of the Generation Resource or SCU.

(2) An owner of a Generation Resource or SCU that notifies the Transmission Provider in writing of a decision to Suspend, and for which the Transmission Provider has determined that the Generation Resource or SCU is required as an SSR Unit may rescind its decision to Retire or Suspend or modify the date of suspension at any time while designated as an SSR Unit by submitting an amended Attachment Y Notice specifying the modified effective date or stating its decision to rescind.

At any time during the Attachment Y Conversion Period, the owner of the Generation Resource or SCU for which the Transmission Provider has determined is required as an SSR Unit may elect to convert the Attachment Y Notice to retirement by notifying the Transmission Provider of its intent to waive the right to both rescind and modify the Attachment Y Notice for the initial rescission period of the Attachment Y Notice. The owner that provides such notification will retain rescission rights (*i.e.* those additionally acquired by virtue of operating as an SSR Unit) only while designated as an SSR Unit after which time the Generation Resource or SCU will have a Retire status and the interconnection service will be terminated in accordance with Section 38.2.7.k.

(iii) Modification or Rescission of an Attachment Y Notice After Commencing a Suspension, Retirement, or an SSR Agreement.

(1) An owner of a Generation Resource or SCU that notifies the Transmission Provider in writing of a decision to Suspend, and for which the resource has not been designated as an SSR Unit or is not continuing to operate pursuant to an SSR Agreement, may rescind its decision to Suspend by submitting an amended Attachment Y Notice to the Transmission Provider stating its intention to rescind any time during the period for rescission following the effective date.

At any time during the Attachment Y Conversion Period, the owner of the Generation Resource or SCU for which the Transmission Provider has determined is not necessary for the reliability of the Transmission System, may elect to convert the Attachment Y Notice to retirement by notifying the Transmission Provider of its intent to waive the right to rescind and modify the Attachment Y Notice. After the owner has waived the right to rescind, the Generation Resource will have a Retire status, and the interconnection service will be terminated in accordance with Section 38.2.7.k. The Attachment Y Notice will no longer be treated as Confidential Information once the owner has elected to waive their right to rescind and committed to retirement of the Generation Resource or SCU.

(2) An owner of an SSR Unit may rescind its decision to Suspend or to Retire or modify the effective date prior to the termination date of the SSR Agreement by submitting an amended Attachment Y Notice specifying the modified effective date or stating its intention to rescind. After receiving an amended Attachment Y Notice from an owner of an SSR Unit to rescind or modify its decision to Suspend or to Retire, the Transmission Provider will then exercise the termination provisions of the SSR Agreement.

At any time during the Attachment Y Conversion Period, the owner of the Generation Resource or SCU for which the Transmission Provider has determined is required as an SSR Unit may elect to convert the Attachment Y Notice to retirement by notifying the Transmission Provider of its intent to waive the right to both rescind and modify the Attachment Y Notice for the initial rescission period of the Attachment Y Notice. The owner that provides such notification will retain rescission rights (*i.e.* those additionally acquired by virtue of operating as an SSR Unit) only while designated as an SSR Unit after which time the Generation Resource or SCU will have a Retire status and the interconnection service will be terminated in accordance with Section 38.2.7.k.

e. Refund of Costs.

(i) If the owner of a Generation Resource or SCU that notifies the Transmission Provider of a decision to Suspend and for which the Transmission Provider has not determined the Generation Resource or SCU is needed for reliability rescinds an Attachment Y Notice prior to commencing suspension, then such owner shall pay the Transmission Provider all of the costs that the Transmission Provider incurred in conducting an Attachment Y Reliability Study.

(ii) The Market Participant that owns or operates an SSR Unit must refund to the Transmission Provider with interest at the FERC-approved rate, all costs, less depreciation, for repairs and capital expenditures that were needed to continue operation of the Generation Resource or SCU and to meet applicable regulations and other requirements (including environmental) while the Generation Resource or SCU was subject to an SSR Agreement if the owner: (1) rescinds its decision to Suspend or to Retire the unit while it is designated a SSR; (2) rescinds its decision to Suspend following its previous designation as an SSR Unit; or **(**3**)** returns a unit to service following its previous designation as an SSR Unit and later retirement of the unit.

(iii) An owner of a Generation Resource or SCU that returns the unit to service upon failure to Retire or Suspend according to an Attachment Y Notice (*i.e*. returns from retirement or rescinds the Attachment Y Notice, including a Generation Resource or SCU that was not a SSR Unit, a former SSR Unit that no longer operates pursuant to an SSR Agreement, or an SSR Unit) will be allocated the total costs of Network Upgrades incurred or financially committed to as of the date of the notification of modification of the decision to Retire or Suspend if all the following apply:

- the rescission obviates the need for such Network Upgrades that were identified by the Transmission Provider in an Attachment Y Reliability Study;
- such Network Upgrades were necessitated solely by the Attachment Y Notice to Suspend; and
- such Network Upgrades were approved by the Transmission Provider's Board of Directors as Attachment FF Appendix A projects.

The total costs will include all pre-construction costs and interest at the FERC-approved rate. Such an owner will also be allocated the costs of expedited construction of such Network Upgrades that were approved for purposes other than dealing with needs identified in an Attachment Y Reliability Study to the extent that such expedited construction was necessitated by the Attachment Y Notice to Suspend.

In the event that multiple Attachment Y studies identified reliability issues that required the Network Upgrades and the owners of the units subject to the studies return their units to operation upon failure to Retire or Suspend (*i.e*. return from retirement or rescind the Attachment Y Notices, including Generation Resources and/or SCUs that were not SSR Units, former SSR Units that no longer operate pursuant to an SSR Agreement, or SSR Units), the owners will be allocated the total costs of such Network Upgrades incurred or financially committed to as of the date of notification of the last modification of a decision to Retire or Suspend if all the following apply:

- the rescission obviates the need for such Network Upgrades that were identified by the Transmission Provider in the Attachment Y Reliability Study;

- such Network Upgrades were necessitated solely by the Attachment Y Notice to Suspend; and
- such Network Upgrades were approved by the Transmission Provider’s Board of Directors as Attachment FF Appendix A projects.

The total costs will include all pre-construction costs and interest at the FERC-approved rate. Such owners will also be allocated the costs of expedited construction of such Network Upgrades that were approved for purposes other than dealing with needs identified in an Attachment Y Reliability Study to the extent that such expedited construction was necessitated by an Attachment Y Notice to Suspend.

Except as provided in this Section, cost responsibility is assigned only for Network Upgrades that are identified to fully alleviate the violations identified in the Attachment Y Reliability Study in connection with a change in a plan to Retire or Suspend a Generation Resource or SCU. Costs of Network Upgrades that have been identified in the MTEP to address Transmission issues other than the issues identified in the Attachment Y Reliability Study of a unit that requests suspension will not be allocated to the owner of that unit if such costs of construction were not expedited as the result of an Attachment Y Notice to Suspend. In accordance with Attachment FF of the Tariff, the estimated costs of such Network Upgrades are included in the MTEP when it is approved by the Board of Directors of the Transmission Provider for inclusion in the MTEP. The Transmission Provider will solicit from the constructing Transmission Owner the actual costs (including the costs of expediting construction, and pre-construction costs, if any) incurred or committed to as of the date of notification for the last modification of a decision to Retire or Suspend. Each owner shall pay its pro rata share of the incurred or committed Network Upgrade costs, based on the relative Generation Verification Test Capacity of each resource whose operation causes the assignment of Network Upgrade costs to its owner. The Transmission Provider will promptly notify the responsible owner of their share of the total costs once actual costs are determined.

f. Execution and Filing of SSR Agreement.

The Transmission Provider shall enter into an SSR Agreement with the Market Participant owning or operating a Generation Resource or SCU that is needed for SSR purposes based on the *pro forma* Attachment Y-1. The SSR Agreement shall state that it incorporates by reference the compensation authorized by the Commission. Resources that are ineligible to continue operating for legal or regulatory reasons, however, shall not be required to enter into an SSR Agreement. If a potential SSR Unit is ineligible or an existing SSR Unit becomes ineligible to continue operation, then the Transmission Provider shall seek to minimize the impact to Load by operating the Transmission System in the same manner as for any Resource that becomes ineligible to continue operation due to Forced Outage.

The Transmission Provider will file an SSR Agreement with the Commission for approval if the Transmission Provider's analysis determines that the Generation Resource or SCU is required for reliability of the Transmission System. All potentially affected parties will receive notification of such Commission filing. SSR service is a contracted service between the Market Participant that owns or operates an SSR Unit and the Transmission Provider and shall be for a term of twelve (12) months, unless the Transmission Provider requires a different term. The Transmission Provider must have available the entire capacity specified in the SSR Agreement of each SSR Unit.

g. Operation of SSR Unit.

Once the Transmission Provider has entered into an SSR Agreement with a Generation Resource or SCU, the Transmission Provider shall have the right to dispatch the SSR Unit at any time for reliability of the facilities within the Transmission Provider Region. The Transmission Provider shall make every attempt to minimize the use of an SSR Unit for reliability purposes. The Transmission Provider will commit the SSR Unit when conditions are identified that require the use of the SSR Unit and will make best efforts to minimize the uneconomic commitment of the SSR Unit. The SSR Agreement found in Attachment Y-1 to this Tariff shall provide for equitable compensation to an SSR Unit when it is dispatched by the Transmission Provider.

h. Scheduling Rules for SSR Units.

The Transmission Provider shall notify Market Participants with SSR Units as to the time period of Energy, Operating Reserve, Up Ramp Capability, Down Ramp Capability, Short-Term Reserve, and/or Other Ancillary Services required from each SSR Unit in accordance with Section 39.1.5 for the Day-Ahead Energy and Operating Reserve Markets, Section 40.1 for Reliability Assessment Commitment processes, and Section 40.1.A.3 Look Ahead Commitment processes.

i. SSR Unit Participation in Markets.

A Market Participant may offer Energy or Ancillary Services from SSR Units into the Day-Ahead Energy and Operating Reserve Market, RAC, or Real-Time Energy and Operating Reserve Market during times when the Transmission Provider has not requested the Market Participant to run the SSR Unit at full capacity unless this would impair the ability of the SSR

Unit to provide the Energy, Operating Reserve, Up Ramp Capability, Down Ramp Capability, Short-Term Reserve, or Other Ancillary Services when requested by the Transmission Provider.

Market Participants that own or operate an SSR Unit shall not use the SSR Unit to: (i) participate in Interchange Schedules; (ii) except for plant auxiliary Load obligations under the SSR Agreement, use the SSR Unit as a Self-Scheduled Resource to submit Self-Schedules for Energy and/or Operating Reserve; or (iii) submit Self-Schedules for Other Ancillary Services, if applicable, to the extent that Other Ancillary Services are required by the Transmission Provider under this Section.

j. SSR Unit Compensation.

(**i)** The Market Participant will be compensated for only costs incurred for the extended operation as an SSR Unit that do not exceed the full cost-of-service (including the fixed cost of existing plant). The hourly component of compensation will be provided as stated in this Tariff. For the determination of any additional compensation, the Market Participant shall submit a filing to the Commission under Section 205 of the FPA that states the additional compensation the Market Participant deems appropriate that is associated with the SSR Agreement filed by the Transmission Provider, but the Market Participant shall not separately file an SSR Agreement. The Market Participant shall provide the Transmission Provider and the Independent Market Monitor with a copy of all compensation-related filings regarding a SSR-designated unit.

(**ii)** Any compensation for the SSR Unit will be reduced by payments for operation of the SSR Unit, according to the provisions in this Tariff. Monthly compensation under Schedule 2 of this Tariff and payments under resource adequacy programs (a percentage of such payments to a Market Participant whose generating unit designations are not made) shall be identified in the filing for compensation submitted by the Market Participant.

Hourly compensation will be provided for those hours in which the SSR Unit has Actual Energy Injections and the SSR Unit is committed by the Transmission Provider in the Day-Ahead Energy and Operating Reserve Market or committed by the Transmission Provider in any of the RAC processes, or in the Look Ahead Commitment ("LAC") process, including any Reliability Assessment Commitment ("RAC") process conducted prior to the Day-Ahead Energy and Operating Reserve Market, in which hours the Transmission Provider shall calculate the Market Participants' Production Cost and Operating Reserve Cost. For the purposes of this calculation, "Production Cost" means the Energy output cost pursuant to Section 39.3.2B Day-Ahead Revenue Sufficiency Guarantee Payments of the Tariff for commitments by the Transmission Provider in the Day-Ahead Energy and Operating Reserve Market or the Energy output cost pursuant to Section 40.2.19 Real-Time Sufficiency Guarantee of the Tariff for commitments by the Transmission Provider in any of the RAC processes, or in the LAC process, including any RAC process conducted prior to the Day-Ahead Energy and Operating Reserve Market, of each SSR Unit based upon Start Up, No Load, and Energy Offer cost components that reflect the actual costs of physically operating the SSR Unit(s). "Operating Reserve Cost" mean the actual cost to provide Operating Reserves. All Production Costs and Operating Reserve Costs will be subject to audit by the Transmission Provider, and will be subject to audit and enforcement by the Independent Market Monitor.

Through the Transmission Provider settlement process, the Transmission Provider will compare the "SSR Unit Compensation," which (for each SSR Unit) is equal to the sum of

Production Cost and Operating Reserve Cost, to the SSR Unit Energy, Operating Reserve Credit, and Short-Term Reserve. The SSR Unit Energy, Operating Reserve, and Short-Term Reserve Credit are those charges and credits calculated pursuant to Sections 39.3 Day-Ahead Energy and Operating Reserve Market, 40.3 Real Time Energy and Operating Reserve Market Settlement and 40.7 Determination of Inadvertent Energy of the Tariff, plus any revenues from Schedule 2 associated with the SSR Unit or from Planning Resource designation and any charges assessed through Schedule 17 and Schedule 24. In those hours where the SSR Unit Compensation is greater than the SSR Unit Energy, Operating Reserve, and Short-Term Reserve Credit for that SSR Unit, the Transmission Provider will make the applicable make-whole payment to Market Participant (such make-whole payment to be equal to the difference between the SSR Unit Compensation and the SSR Unit Energy, Operating Reserve, and Short-Term Reserve Credit). In those hours where the SSR Unit Compensation is less than the SSR Unit Energy, Operating Reserve, and Short-Term Reserve Credit, the Transmission Provider will debit from Market Participant (such debit to be equal to the difference between the SSR Unit Energy, Operating Reserve, and Short-Term Reserve Credit and the SSR Unit Compensation). If the SSR Unit receives revenue pursuant to Sections 39.3 Day-Ahead Energy and Operating Reserve Market and 40.3 Real Time Energy and Operating Reserve Market Settlement of the Tariff in hours other than those described above, the Transmission Provider will debit those revenues from the Market Participant.

(iii) The Market Participant shall file with the Commission for a Monthly SSR Payment for compensation not covered by the hourly compensation stated in the previous sub-section. The Market Participant's filing shall state the requested Monthly SSR Payment along with its sub-components (including amounts for monthly Schedule 2 payments for each SSR Unit) and applicable cost support, including an affidavit executed by an officer of the Market Participant attesting to the accuracy of the submitted cost information. The Market Participant shall provide the Monthly SSR Payment information for each SSR Agreement, including any renewals of an SSR Agreement, and may update the information in a Section 205 filing to revise such Monthly SSR Payment following any material, unforeseen circumstances affecting the SSR Unit that changes the costs incurred by the Market Participant. The Transmission Provider shall pay the Market Participant the Monthly SSR Payment as directed by the Commission, commencing on the effective date established by the Commission.

The filing for the additional compensation should evaluate, at a minimum, the following factors in negotiating compensation for an SSR Unit: (1) operations and maintenance labor expenses directly related to the SSR Unit; (2) administrative expenses directly related to employees at the SSR Unit, including employee expenses environmental fees, safety and operator training, office supplies, communications, and plant inspection/testing expenses; (3) non-labor maintenance expenses, including chemical and materials consumed during maintenance of the SSR Unit and rental expenses for maintenance equipment used to maintain the SSR Unit; (4) taxes, permit and licensing fees, site security expenses, and insurance; (5) carrying charges**,** including charges for maintaining reasonable levels of inventories of fuel and spare parts that result from short-term operating unit decisions based on Good Utility Practice; (6) corporate expenses, including those incurred for legal services, environmental reporting, and procurement; (7) costs associated with capitalized projects; (8) depreciation, and (9) return on the undepreciated plant costs for the SSR Unit.

k. Termination of Interconnection Service.

Except as provided in Attachment X, the Transmission Provider shall file with the Commission to terminate the interconnection service to the Transmission Provider's system held by an owner of a Generation Resource or SCU or Pseudo-tied out Generator, that certifies by submitting an Attachment Y Notice that it plans to Suspend a Generation Resource or SCU or Pseudo-tied out Generator, upon the latter of: (1) the termination of an SSR Agreement; (2) the effective date for which the owner has elected to convert the Attachment Y Notice to retirement by waiving the right to rescind the decision; or (3) the end of the period for rescission for which the owner has not waived the right to rescind. Such termination of interconnection service shall be contained in a filing with the Commission and also posted by the Transmission Provider on its OASIS to the extent that such interconnection service was filed with the Commission, and shall otherwise be terminated by the Transmission Provider by a posting on its OASIS. If the owner rescinds or modifies the Attachment Y Notice in accordance with Section 38.2.7.d, the owner of such resource may retain its interconnection service and continue to operate after the conclusion of an SSR Agreement or the date specified in the Attachment Y Notice.

l. Allocation of SSR Unit Costs.

The costs pursuant to the SSR Agreement shall be allocated to the LSE(s) which require(s) the operation of the SSR Unit for reliability purposes.

m. Annual Review of SSR Unit Status.

On at least an annual basis, the Transmission Provider will review Generation Resource or SCU characteristics to determine whether the Generation Resource or SCU is qualified to remain as an SSR Unit in coordination with a review of the Transmission Provider’s annual regional transmission expansion plan in accordance with Attachment FF. If an SSR Unit continues to be required for reliability of the Transmission System, then the Transmission Provider will have the unilateral right to negotiate and enter into a subsequent SSR Agreement by providing the Market Participant at least ninety (90) days advance notice prior to the termination date of the existing SSR Agreement and by negotiating and filing a new SSR Agreement at the Commission. If not, the SSR Agreement will expire by its own terms and the Generation Resource or SCU will lose its SSR Unit status and will resume suspension in accordance with the Attachment Y Notice or Retire. Any subsequent SSR Agreement also shall be filed with the Commission.

n. Time Limitations on Suspension.

An owner of a Generation Resource or a SCU or a Pseudo-tied out Generator may request suspension pursuant to the provisions of this Section 38.2.7 and remain for a maximum of thirty-six (36) cumulative months during any five (5) year period under any combination of suspended and SSR-designated statuses. An owner of a Generation Resource or a SCU or a Pseudo-tied out Generator that had not exhausted its maximum period may request an additional suspension period by submitting a new Attachment Y Notice four full Quarterly Study Periods prior to the effective date of the extension period, provided that the combined period is not greater than thirty-six (36) months in a five (5) year period. If a Generation Resource or a SCU or a Pseudo-tied out Generator does not return to service at the end of the thirty-six (36) month maximum suspension period, the Transmission Provider will terminate interconnection service of the resource pursuant to Section 38.2.7.

o. Non-Binding Informational Studies.

An owner of a Generation Resource or a SCU may complete an Attachment Y-2 to request that the Transmission Provider conduct a study to determine whether it is likely that a portion or all of such Generation Resource of SCU would qualify as an SSR Unit. The Transmission Provider will collaborate with the affected Transmission Owners and NERC-registered Transmission Planners, and if appropriate, will consult with a retained consultant to evaluate whether the facility is required for the reliability of the Transmission System. The Transmission Provider will appropriately identify any Confidential Information regarding a decision to Suspend that the Transmission Provider transfers to any entity. An entity that receives Confidential Information must agree in writing to maintain such confidentiality, or to any confidentiality obligations owed to Transmission Provider under the Tariff or related non-disclosure agreement, and to comply with applicable Standards of Conduct found in 18 C.F.R. § 358. The owner will not be bound to the change of status indicated in an Attachment Y-2 request. Along with a completed Attachment Y-2, such owner shall submit a study deposit of $70,000 to the Transmission Provider for the reasonable costs and expenses of such study. The Transmission Provider shall invoice such owner for all costs and expenses incurred in addition to the deposit amount, or shall refund any unused portion of such deposit upon completion of the study.

The Transmission Provider will process multiple Attachment Y-2 requests in the order in which the Attachment Y-2 requests are received. The Transmission Provider shall use reasonable efforts to submit the results of such study to the owner upon its completion within 150 days of receipt of the deposit and completed Attachment Y-2, unless an alternative period is mutually agreed to. The Transmission Provider shall treat Attachment Y-2 as Confidential

Information. If an owner rescinds an Attachment Y-2 study request, then such owner shall not receive the results of the study and the owner shall pay the Transmission Provider all of the costs incurred in conducting the study up until the date of such rescission.

Once a response is provided by the Transmission Provider to the owner, the Transmission Provider shall promptly notify the Independent Market Monitor of any Resource that may qualify as an SSR Unit. The results of such study will provide the owner with the outcome if the owner elects to submit an Attachment Y Notice to request SSR status in the future and does so in accordance with Section 38.2.7.p.

The Transmission Provider shall maintain regional power flow models pursuant to Section I.C of Attachment FF, for use by the owner of a Generation Resource or a SCU choosing to conduct a study.

p. Submission of Attachment Y Notice Following Non-Binding Reliability Studies Under Y-2.

The Attachment Y Notice following a non-binding Y-2 request must be submitted at least four full Quarterly Study Periods prior to the date of the planned change of status. The Transmission Provider shall conduct the subsequent Attachment Y process consistent with timeline and milestones in Section 38.2.7.