BEFORE THE IDAHO PUBLIC UTILITIES COMMISSION

IN THE MATTER OF THE APPLICATION OF ROCKY MOUNTAIN POWER FOR AUTHORITY TO INCREASE ITS RATES AND CHARGES IN IDAHO AND APPROVAL OF PROPOSED ELECTRIC SERVICE SCHEDULES AND REGULATIONS	)))))))	CASE NO. PAC-E-24-04 DIRECT TESTIMONY OF JOHN TSOUKALIS

ROCKY MOUNTAIN POWER

CASE NO. PAC-E-24-04

May 2024

I. INTRODUCTION AND QUALIFICATIONS

Q. Please state your name, position, and business address.

A. My name is John Tsoukalis. I am a Principal at The Brattle Group. My business address is 1800 M Street NW, Suite 700N, Washington, DC 20036.

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

A. I am submitting this direct testimony before the Idaho Public Utility Commission ("Commission") on behalf of PacifiCorp d/b/a/ Pacific Power ("PacifiCorp" or the "Company").

Q. Please describe The Brattle Group.

A. The Brattle Group is a consulting firm with a professional staff in excess of 400 individuals and offices in North America, Europe, and the Asia-Pacific region. The firm was founded in 1990 in Cambridge, Massachusetts. We have a large electric power practice focused on market, regulatory, and financial matters in the industry. We are an industry leader and provide planning support as well as expert testimony on electricity rate design, transmission system expansion and coordination, analysis of the benefits and risks of investments or ownership of electricity assets and contracts, and analysis of wholesale electricity markets. We also advise clients on the design, pricing, and risk management of wholesale and retail services, and provide testimony on these matters before regulatory agencies for electric utilities and other market participants.

Q. Please summarize your education and professional experience.

A. I am an energy economist and regulatory expert with an educational background in economics and over 10 years of experience advising clients in the electric power industry. For multiple clients, I have assessed the benefits, costs, and operational impacts of participation in regional wholesale markets in the western U.S. and in the southeastern U.S. I have analyzed and modeled the power system in various parts of North America, advised clients on market entry decisions, regulatory and policy matters, market design, transmission investment decisions, rate design, and compliance with market power rules. In addition, I have assisted clients in comprehensive organizational strategic planning efforts.

I have provided testimony before the Federal Energy Regulatory Commission ("FERC") on several occasions, before the Alberta Utilities Commission, and before a U.S. District Court.

I hold a Bachelor of Arts in Economics from Washington and Lee University, a Master of Science in Economics from The Barcelona Graduate School of Economics, and a Master of Science in Economic Analysis from the Universitat

Autònoma de Barcelona. My resume is provided in Exhibit No. 29.

Q. Please summarize the purpose and conclusions of your direct testimony.

A. My testimony addresses how the Extended Day-Ahead Market ("EDAM")—being developed jointly by PacifiCorp, the California Independent System Operator ("CAISO"), and other potential participants in the region, with operations expected to begin in 2026—will create benefits that reduce operating costs and eliminate the need for risk-sharing under the Energy Cost Adjustment Mechanism ("ECAM"). The EDAM's market clearing process achieves these benefits because it is an enhanced way of scheduling and dispatching resources for efficient use of all the power plants in a very large region. It is designed to solve for the lowest cost expected day-ahead outcome for customers subject to the constraints on the power system. The EDAM will optimize the use of all the transmission and generation resources of its members, which will cause it to solve for a lower cost outcome than would be possible by the individual members using only their own transmission, generation, and bilateral trading. Therefore, the Company will no longer have the need or the ability to unilaterally try to improve upon the market operations, once they are provided through EDAM. For this same reason, the incentive structures under the ECAM will become unnecessary, redundant, and ineffective. That is, by joining the EDAM, the pooling of transmission and generation assets with neighboring utilities and allowing the market to commit and dispatch generation resources will provide a lower-cost outcome than what the Company could achieve on its own.

This improvement occurs not because PacifiCorp's existing market activity processes are ineffective but because the EDAM will incorporate a much broader and more accurate information set about the available trade and scheduling opportunities in the region, and it will automatically schedule those for all participants a day ahead of real time operations. This efficiency from participation in the EDAM eliminates the need for and the potential benefit of any ECAM risk-sharing incentives on the Company to efficiently schedule and dispatch its generating fleet and trade bilaterally, because the market will do that automatically.

Lastly, I review the mechanism used in other states to address over- or under-recovery of ECAM-like costs. I find that most other comparable states have full pass-through cost recovery of net power costs, without any deadbands or sharing bands. This is also true in states where utilities participate in regional wholesale markets like the EDAM. This indicates to me that those states and regulators have realized that risk sharing of operational variances is not productive or helpful once this kind of market structure is in place.

II. THE EDAM

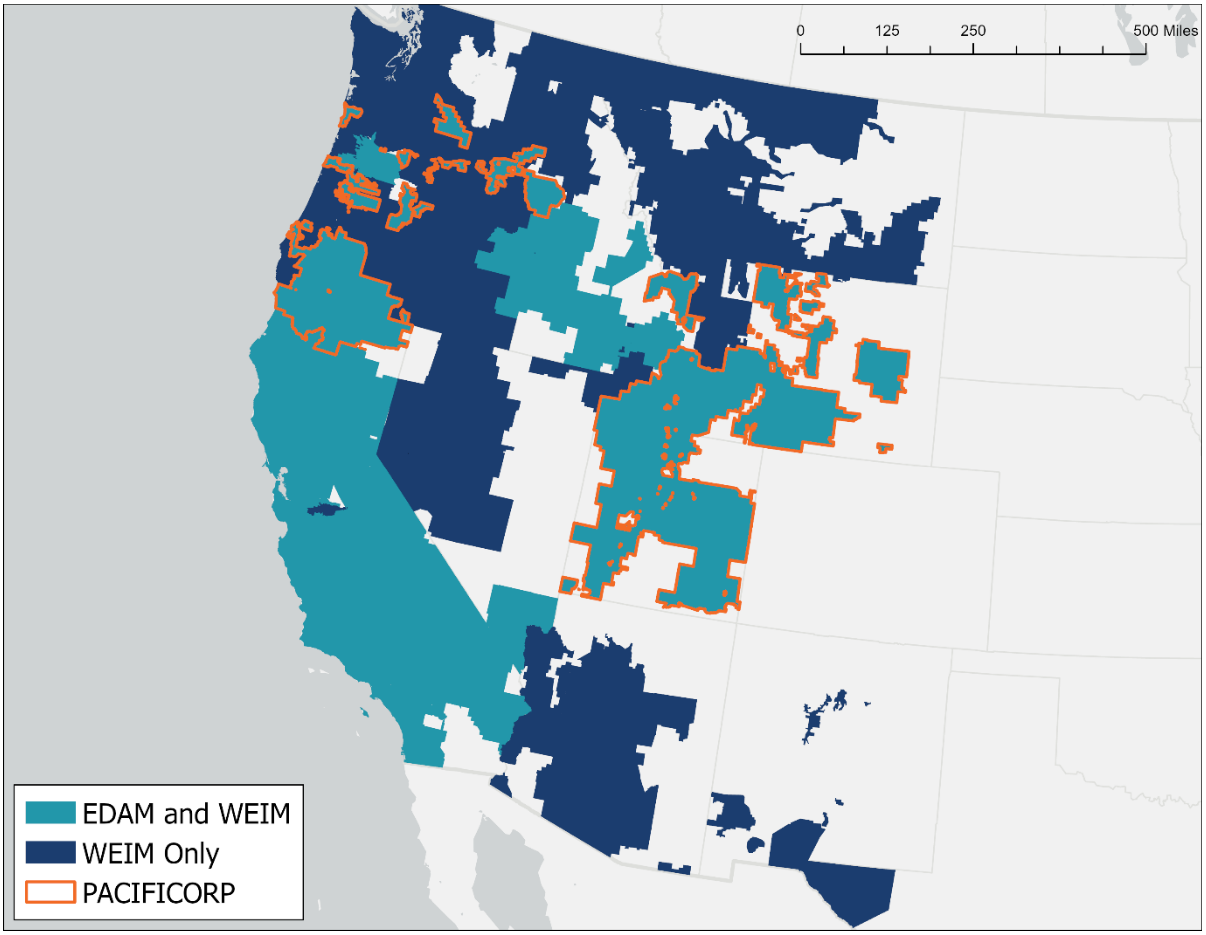
Q. What is the EDAM?

A. The EDAM is a day-ahead energy market that builds on the CAISO's current day-ahead energy market, allowing utilities in the Western Electricity Coordinating Council ("WECC") that are not CAISO members to voluntarily participate. The EDAM will be administered by the CAISO, and will provide centralized optimization of unit commitment, dispatch, and power transfers between participants to most efficiently serve forecasted demand across the market footprint. The EDAM will cover a larger footprint than the CAISO's existing day-ahead market (and likewise, much larger than PacifiCorp's system footprint) and will jointly optimize the generation and transmission assets of participating non-CAISO utilities in addition to those of existing CAISO members to find the most efficient market solution subject to constraints on the system. In addition to CAISO members, the utilities that have announced their intention to participate in the EDAM include PacifiCorp, most members of the Balancing Authority of Northern California ("BANC") (including the Sacramento Municipal Utility District ("SMUD")), the Los Angeles

Department of Water and Power ("LADWP"), the Idaho Power Company, and Portland General Electric.[1] The already-committed EDAM footprint as of May 2024 is shown in Figure 1 below. These are many of the same companies that PacifiCorp currently tries to trade with every day, looking for opportunities to substitute available cheaper resources for its own, or to sell excess power supply on its system to other systems. The EDAM will do that automatically.

[1] *PacifiCorp to build on success of real-time energy market innovation as first to sign on to new Western day-ahead market*, PACIFICORP (Dec. 8, 2022), https://www.pacificorp.com/about/newsroom/news-releases/EDAM-innovative-efforts.html; *EDAM gains more momentum at recent Las Vegas forum*, CALIFORNIA ISO (Sept. 7, 2023), https://www.caiso.com/about/Pages/Blog/Posts/EDAM-gains-more-momentum-at-recent-Las-Vegas-forum.aspx (the Sacramento Municipal Utility District next announced its intent to join EDAM in the fall of 2023); *Approval of Participation in the California Independent System Operator's Extended Day-Ahead Market,* LOS ANGELES DEPARTMENT OF WATER AND POWER (Feb. 2024), https://ladwp.primegov.com/Portal/Meeting?meetingTemplateId=3019; *Idaho Power and Portland General Electric signal intent to join EDAM*, CALIFORNIA ISO (Mar. 21, 2024), https://www.caiso.com/Documents/idaho-power-and-portland-general-electric-signal-intent-to-join-edam-iso-statement.pdf.

Figure 1. The planned EDAM Footprint as of February 2024



Q. Please describe the operating process of the EDAM.

A. EDAM operations fall into three phases: pre-market, the day-ahead market clearing, and after-market. The outcome of the EDAM will be integrated with the Western Energy Imbalance Market ("WEIM"), the existing real-time balancing market administered by the CAISO. The three market phases will operate as follows:

- The pre-market timeframe takes places the morning of market clearing prior to 10 a.m. (on the day prior to delivery). In this timeframe, participants bid their resources and demand into the market, report forecasts of variable energy resources to the CAISO, and report operating reserve needs for their Balancing Authority

Areas (“BAAs”) to the CAISO. Market participants will also report their transmission obligations for the next day, allowing the EDAM to know how much transmission capability is available for market transfers. In this timeframe, the CAISO will conduct the resource sufficiency test to ensure that participants have enough resources available to meet their own expected load along with necessary operating reserves.[2]

- The day-ahead market timeframe starts at 10:00 a.m. the day prior to delivery and runs until 1:00 p.m. of the same day. The CAISO uses the information collected in the pre-market timeframe, including resource and load bids and available transmission capability, and runs the market clearing engine to achieve the most efficient set of resource commitments, day-ahead dispatch instructions, and energy transfers to meet demand. This timeframe also includes greenhouse gas (“GHG”) emissions accounting mechanisms that track the emissions associated with meeting demand in states that have GHG pricing programs.[3] At 1:00 p.m., the day prior to delivery, market prices are published, and commitment and dispatch instructions are shared with participants.[4]

- The after-market period, which takes place over the weeks and months following day-ahead market clearing, includes financial settlements, such as the allocation of transmission congestion charges, payments to generators, collection from load, dispute

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[2] CAISO Extended Day-Ahead Market – Draft Tariff Language, California ISO (July 25, 2023) Section 33 *available at* https://www.caiso.com/InitiativeDocuments/UpdatedRevisedDraftTariffLanguage-ExtendedDay-AheadMarket-Section33-ExtendedDayAheadMarket.docx.
[3] Based on the current state policies and announced members of the EDAM, that would include both California and Washington.
[4] *CAISO Day-Ahead Market Overview*, California ISO (Dec. 2, 2019), https://www.caiso.com/Documents/Presentation-Existing-Day-Ahead-Market-Overview.pdf.

resolution, assessing penalties for market rules violations, and greenhouse gas emissions cost accounting.[5]

The EDAM will be integrated with the existing WEIM administered by the CAISO. The WEIM's function is to efficiently balance any variations that occur relative to what was expected and planned for in the EDAM. Like EDAM, the WEIM extends the opportunity to participate in the CAISO's real-time market to non-member utilities. The WEIM provides centralized coordination of generation and transmission assets down to a five-minute real-time energy market, helping participating utilities to cure (and be compensated for fixing or creating) real-time energy imbalances in an efficient way.

Since its inception in 2014, the WEIM has generated over $5 billion in benefits for customers of member utilities through "[production] cost savings, increased integration of renewable energy, and improved operational efficiencies including the reduction of the need for real-time flexible reserves."[6] PacifiCorp has been a member of the WEIM since 2014.

The WEIM has demonstrated the customer savings possible through regional cooperation in the WECC, and the

[5] *Id.*; CAISO Extended Day-Ahead Market – Draft Tariff Language, July 23, 2023, Section 33.
[6] *Energy Imbalance Market Report: Fourth Quarter 2023*, California ISO (Jan. 2024), https://www.westerneim.com/Documents/iso-western-energy-imbalance-market-benefits-report-q4-2023.pdf.

creation of the EDAM will further increase the customer savings created by the WEIM. The EDAM will extend the same type of customer savings from regional cooperation to the process of scheduling resources, which will position the system in the day-ahead to more efficiently serve demand. In effect, the EDAM and WEIM will work together to provide further cost savings to customers than the WEIM alone can provide. The WEIM will continue to be able to adjust certain commitment decisions, dispatch schedules, and energy transfers determined by the EDAM, thus re-optimizing the system closer to real-time based on changing conditions after the close of the EDAM.

Q. Please contrast how the EDAM will deliver efficiencies and customer cost-savings compared to decentralized regional system operations today.

A. The EDAM delivers operational efficiencies that reduce customer electricity costs by optimizing the usage of generation and transmission resources across its footprint and automating economically advantageous energy transfers among member utilities, compared to the status quo today where each individual utility schedules and dispatches their own resources and transmission and trades bilaterally.

Today, utilities outside of a market largely rely on their fleet of owned or contracted generation resources to serve electric demand, making bilateral trades when their in-house traders identify opportunities to do so that will result in lower costs for customers. Utilities generally dispatch their resources following a merit order approach that utilizes the lowest-cost resources first,[7] with some variation in dispatch strategies and outcomes arising from differences in operator experience, regulatory constraints, utility-specific heuristics, and the effectiveness of bilateral trading.

Transition to a regional day-ahead market, like the EDAM, will improve on this process in several ways:

- The use of security-constrained unit commitment ("SCUC") and a security-constrained economic dispatch ("SCED") fully optimizes the usage of generation and transmission assets. The EDAM will employ these advanced tools for scheduling and dispatching transmission and generation resources, like the WEIM and the CAISO Day-Ahead Market today, which are more efficient in finding least-cost outcomes than dispatch strategies used by utilities today.

- The EDAM will have access to a more complete set of information about the system than any individual utility is able to leverage when scheduling and dispatching their own resources. The regional market will collect bids, forecasts, outage data, transmission usage data, and other information from all market members, and utilize it to solve for least-cost outcomes. An individual utility would have the

[7] The Department of Energy's survey of utility economic dispatch methods notes that "cost-minimization goals and methods appear to vary across the industry." *The value of economic dispatch: a report to congress pursuant to section 1234 of the energy policy act of 2005*, UNITED STATES DEPARTMENT OF ENERGY (Nov. 7, 2005) p. 21, *available at* https://eta-publications.lbl.gov/sites/default/files/value-econ-dispatch-congress.pdf.

same information for its own system but is forced to rely on estimates for neighboring utilities.

- The EDAM will more efficiently utilize the transmission infrastructure in its footprint than the current system operations. This occurs for two reasons. First, EDAM members will make their transmission available to the market without short-term transmission charges (depancaking). Second, the SCUC and SCED processes will automatically utilize the complete physical capacity of the transmission system to execute market transfers, unlike utilities today that can only schedule off-system purchases or sales if they have secured transmission rights from the point of sale to the point of delivery (contract path approach).

- The EDAM will cover a larger geographic footprint than any of the individual member utility service territories. The large geographic footprint implies a diverse pattern of resource production, load, and a diversity of conventional generation resources across the market. Access to a diverse mix of resources and the non-coincidence between loads across the footprint will allow the market to leverage the lowest cost resources, including variable generation that might otherwise be curtailed.

All these factors will contribute to more trading of economic energy across the EDAM footprint than is achievable today under isolated utility operation and bilateral trading, which will lower power costs for customers. I explain each of these improvements over current operations provided by the EDAM in more detail in the remainder of this section of my testimony.

Q. What are SCUC and SCED?

A. SCUC and SCED are economic optimization processes that find least-cost solutions for committing and dispatching generation facilities in a way that obeys the physical capabilities and limitations of generation and transmission facilities and maintains reliability in the face of operational uncertainties.[8,9]

Serving demand, or forecasted demand, in each operational period involves a series of decisions about which generating plants will need to be turned on and what their output levels should be. The decisions regarding what plants should be turned on are known as "unit commitment" decisions and are typically taken a day in advance of real-time operation to provide plants with adequate time to come online.[10] SCUC solves this problem of what plants should be committed so that they are available the next day. Once committed, the decisions regarding plants' specific output levels are known as "dispatch" decisions

[8] Such constraints include generating facility min/max output levels and ramping capabilities, transmission line ratings, and the impacts of contingencies on power flows over remaining transmission facilities.

[9] SCED and SCUC are designed to achieve "economic dispatch," which the FERC defines as "the operation of generation facilities to produce energy at the lowest cost to reliably serve customers, recognizing any operational limits of generation and transmission facilities." *The value of economic dispatch: a report to congress pursuant to section 1234 of the energy policy act of 2005*, United States Department of Energy (Nov. 7, 2005), *available at* https://eta-publications.lbl.gov/sites/default/files/value-econ-dispatch-congress.pdf.

[10] Commitment decisions for some generation facilities with long startup times can be issued as much as a week or more in advance of operations. On the other hand, some fast-start resources like gas combustion turbines can start up in less than an hour and can therefore be committed after the day-ahead market timeframe. Some resources can elect to provide generation regardless of their competitiveness in the market in a process known as "self-scheduling." Facilities with long lead times, high start costs, and low operating costs (such as nuclear plants) frequently self-schedule into the market.

and can be updated as late as minutes ahead of real-time operations. Dispatch decisions are solved using SCED.

SCUC and SCED will automatically account for potential transmission outages, which helps mitigate the reliability risks and economic costs of unexpected changes in system conditions. The optimization algorithm of SCUC and SCED will test and adjust the unit commitment and dispatch solution under selected outage conditions to optimally position and operate the system in a way that maintains reliability and minimizes costs under uncertainties like those in the examples above.

The SCUC optimization process is typically run one day ahead of operation,[11] and considers expected demand, generation facilities' availability and technical parameters (including start-up costs), grid constraints, and other system conditions, such as weather. SCUC outputs a set of instructions about which generating facilities should be switched on to be ready to meet demand and provide sufficient additional backup capacity ("operating reserves") to reliably serve demand at lowest cost.

The SCED optimization process that will be used in the EDAM creates a day-ahead dispatch schedule. SCED is then run more frequently in WEIM for five-minute intervals

[11] The SCUC optimization nonetheless considers forecasts for operations beyond a day in advance to issue commitment instructions for generating facilities with long lead times.

in advance of real-time operations. SCED relies on the most up-to-date information about system conditions, short-term demand forecasts, and North American Electric Reliability Corporation ("NERC") reliability standards to determine a set of generator dispatch instructions that deploy available plants at the lowest cost.[12]

The output of the SCUC and SCED includes the necessary energy transfers between market members to make the unit commitment and dispatch solution feasible while supporting reliability. For example, the SCUC and SCED conducted under the EDAM may find that it is economic to turn off one member's generation resource that would have otherwise been committed by that member. In this case, the EDAM will automatically schedule the power transfers necessary to serve load in that member's service area, absent the output of that generation resource.

Q. How do SCED and SCUC improve the efficiency of system operation and reduce costs for customers compared to system operations today?

A. When SCED and SCUC are not used, utility dispatch strategies vary,[13] typically relying on heuristic methods and knowledge of their systems to make unit commitment and

[12] *The value of economic dispatch: a report to congress pursuant to section 1234 of the energy policy act of 2005*, United States Department of Energy (Nov. 7, 2005), *available at* https://eta-publications.lbl.gov/sites/default/files/value-econ-dispatch-congress.pdf.

[13] *Id.*

dispatch decisions that are not as effective as true optimization algorithms. Under this approach, system operators make unit commitment and dispatch decisions based on forecasts of demand, renewable energy output, generation and transmission availability, and other factors that can affect their ability to reliably serve demand.[14] The objective, similar to SCUC and SCED, is to achieve the lowest possible cost of commitment and dispatch. If there were no technical limitations on the power system and the operator had perfect knowledge of future demand, achieving the lowest-cost outcome would be easy, as system operators would simply turn on and dispatch its most efficient generation facilities to their maximum output level until reaching enough generation to serve load. In practice, the power system's technical limitations, such as transmission constraints, and an imperfect knowledge of future system conditions makes such a theoretical lowest-cost solution impossible. This is where SCUC and SCED can improve the outcome for customers.

Given the technical limitations and imperfect information faced by system operators, the efficiency of resulting decisions for a given set of system conditions can thus vary, depending on the experience and knowledge

[14] Additional factors affecting dispatch decisions include generation ramping rates, changing transmission line ratings, trading activity with neighboring utilities, fuel availability, and others.

of the system operators. The reliance on the "human decisions" in selecting commitment and dispatch solutions is inherently less efficient than a system-wide optimization and introduces additional costs beyond the practically-attainable minimum. Even if utility methods are very sophisticated, at the very least those decisions are not coordinated across all the utilities in the region, even though they depend on what others are planning to do.

The benefit of SCED and SCUC is that the resulting commitment and dispatch decisions are automated to achieve economically optimal outcomes—meaning lowest cost—while obeying the technological and engineering limitations of the system. The high computational speed allows SCED and SCUC to consider a broader set of solutions than a human operator could consider, which allows it to find a more optimal, lower-cost commitment or dispatch solution than a human system operator could.

Q. Please explain how the EDAM will be able to utilize a larger and more accurate set of information to optimize the use of transmission and generation resources than individual utilities.

A. In addition to pooling their generation and transmission resources, market participants in the EDAM are also, in effect, pooling information (though not directly sharing it as such, just providing it to the market administrator).

Market participants will bid all their generation resources (at bids that typically reflect the operating cost of the generation resource) and load into the market, as well as share information with the CAISO (the market administrator for the EDAM) on the availability of their transmission assets. The CAISO will utilize all this information to run SCUC and SCED and clear the market. Individual utilities only have information about their own systems, which limits their ability to identify cost-reducing opportunities to trade power with neighbors.

Through the bids and information collected from market participants, the EDAM will be able to optimize the usage of transmission and generation assets for the market with the knowledge of what the costs of generation resources are across the entire footprint and what transmission capacity is available to deliver the lowest-cost resources to load. As a result, the EDAM can then find dispatch efficiencies that would be imperceptible and unachievable for individual market participants who do not know the operating costs or transmission availability for neighboring utility systems.

Q. How will the EDAM be able to schedule the transmission infrastructure more efficiently in the market than each member utility operating individually?

A. There are two reasons why the EDAM will be able to more efficiently schedule the transmission infrastructure compared to today's utility-specific approach.

First, the EDAM will eliminate short-term transmission service charges (wheeling fees) for transaction between members (depancaking). This will lower the cost of transacting power in the EDAM compared to the cost of buying or selling power bilaterally. The lower transaction cost in the EDAM will increase the volume of trading that is economic in the market relative to the current bilateral trading process in the WECC. The higher volume of economic energy trading in the market will increase usage of the transmission system and lower costs for customers.

Second, the EDAM will schedule the transmission in the market on a physical power flow basis compared to the contract path basis used today. The contract path trading model reduces access to full physical transmissions capability between utilities and limits inter-utility power transfers, reducing the potential cost savings of importing cheaper energy from neighboring utilities. The limitation of the contract path approach is that it is based on an individual utility's assessments of flow capacity on their transmission infrastructure that are developed without information on unit commitment, dispatch, and transmission usage on neighboring utilities' systems. Therefore, while this approach is necessary in the absence of a regional market to ensure the system is not overloaded, it does not accurately reflect the amount of power that can flow on the power system. The EDAM will not be forced to make such siloed assessments of grid capacity and will instead be able to rely on the full physical rating of the transmission infrastructure in the market.

In addition, under the contract path approach, the allocation of rights to use the transmission capacity, which is already artificially low due to the incomplete information available to each utility as I just described, is inefficient. In the contract path approach, a utility that wishes to execute a sale or purchase of power must either control transmission rights between the point of sale and the point of delivery or must identify if any other utility has those rights available and then secure the use of those rights. This search and matching problem creates inefficiencies and additional costs to executing power transfers. Utilities operate with imperfect information on what transmission rights are available at any given moment, which limits their visibility into what economic energy transactions are feasible. The contract path use of transmission causes economically advantageous trades between two utilities to be intrinsically limited. This happens when the trading parties cannot secure the necessary path of transmission rights to execute trades, even if there is available lower-cost generation and capacity on the physical transmission facilities.

The EDAM will bypass both obstacles in current system operations and deliver lower-cost outcomes to customers. Pooling transmission under the EDAM removes this barrier to economic trading and replaces it with automatic maximal use of the grid based on marginal costs thereby enabling a more efficient dispatch and power transfers. Under the EDAM, participating utilities would collectively offer their physical transmission assets and contractual transmission rights for use in the market. In addition, transfers between utilities will be optimized without imposing transmission service charges on individual transactions. The increased transmission availability and lack of financial barriers to its usage makes possible the increased economic efficiencies from market-wide SCED and SCUC, and the associated customer benefits.[15,16]

Q. Please explain how the larger geographic footprint of the EDAM, compared to individual utility member service territories, will be beneficial for customers compared to today's utility-specific operations.

A. The large geographic scale of a regional market like the EDAM creates diversity in generation resources and load across the footprint, both of which will help reduce customer costs.

- For generation resources, both conventional thermal and renewable resources vary in their cost or production patterns by geography, which the market will leverage to increase the utilization of the lowest cost resources, including renewables, as much as is feasible given the operational limitations of the grid.

[15] In FERC Order 2000, the Commission concluded that "a large ISO would: (1) be able to identify and address reliability issues most effectively; (2) internalize much of the loop flow caused by the growing number of transactions; (3) facilitate transmission access across a larger portion of the network, consequently improving market efficiencies and promoting greater competition; and (4) eliminate "pancaking" of transmission rates, thus allowing a greater range of economic energy trades across the network." Order No. 2000, FERC, *Docket No. RM99-2-000* (Dec. 20, 1999).

[16] While transmission charges are not imposed in the EDAM optimizations, participating utilities and their customers will be held harmless for the reduction of transmission service revenues and additionally benefit from the congestion and transfer revenues associated with EDAM power transfers between members.

- For load, weather patterns will create diverse levels and patterns of demand for power across the footprint that allow the market to transfer low-cost power from areas with relatively lower load to areas with relatively higher load.

To illustrate how a diverse set of thermal generation resources can reduce costs, consider an example of two gas-fired generation resources, one in Wyoming and one in Arizona. On any given day, the cost of procuring and delivering natural gas to a generation facility in Wyoming may be significantly different than the cost of procuring it and delivering it to a generation facility in Arizona. This may occur due to congestion or service interruptions on the natural gas delivery system, or changes in local supply and demand conditions for natural gas, which could be driven by extreme weather events. Gas prices also vary geographically within a day when fuel supply conditions are tight. If a utility with gas generation in Wyoming is aware of the fuel price differences across the region, it might be able to arrange for bilateral power purchases when gas is relatively expensive in Wyoming or arrange to sell excess power when gas is relatively less expensive in Wyoming, but that will depend on the ability to procure transmission service and to find a willing counterparty for the transaction. However, the EDAM will automatically see these price differences due to the bids submitted by market participants, and the SCUC and SCED utilized by the EDAM will maximize the usage of the lowest-cost resources and minimize the usage of the higher-cost resources in the market footprint each day and each hour, taking advantage of the diverse set of generating units in the regional footprint.

The impact of geographic diversity is even more pronounced for renewable resources that produce based on weather conditions (e.g., recent levels of precipitation, wind speeds, and solar exposure). For example, wind farms in central Wyoming likely have correlated production patterns. Therefore, a utility with wind resources only in Wyoming will likely experience periods of low wind production, forcing it to rely on its thermal resources to supply customers. However, a regional market with wind resources in Wyoming, New Mexico, Idaho, and Oregon can leverage the diverse pattern or wind production across that broad geographic footprint. When wind resources in Wyoming are not producing, that market can rely on wind production in the other areas. The same concept applies to solar resources in a larger regional market. Moreover, a large geographic footprint is likely to have many types of renewable resources, such as the WEIM footprint that includes solar rich areas in the southwest, hydro resources in the Pacific Northwest, and abundant wind resources in Wyoming, Montana, and New Mexico. As described above, the EDAM will automatically see the forecast diversity of renewable production in the day-ahead timeframe and schedule the system in the best way to leverage that diversity.

Lastly, the geographic scale of a regional market like the EDAM increases the load diversity of member utilities. Therefore, the timing of resource needs across utilities many hundreds of miles apart (or more) will likely not coincide, due to time zones, weather conditions, and other factors. Acting independently, each utility must schedule enough resources for their own expected peak and operating reserves the following day, but as a group some of those needs will almost assuredly offset each other to some degree. This is analogous to insurance—a bigger pool is less risky and less expensive to cover because the likely claims are not coincidental. This slack from greater diversity means that a regional wholesale power market, like the EDAM, can put surplus low-cost generation capacity available in one member-utility's system to use for serving the load of another member, with the economic benefits of doing so split between the two EDAM members. The diversity in load patterns between members also means that each individual member can reliably hold fewer operating reserves than they would be able to outside of the market.

Q. How do the advantages of a diverse geographic footprint change as some states and utilities in the region pursue a new mix of generation resources as a result of state policies?

A. The advantages of geographic diversity become increasingly important as states and utilities in the western U.S. continue to decarbonize their generation fleet by integrating more renewable resources and retiring aging fossil fuel-fired resources. As the system continues to integrate more variable generation resources, a regional wholesale market will have more opportunities to offset generation of one market participant's area with excess generation in another market participant's area. This opportunity increases as the geographic scope and diversity of the regional market footprint increases, bringing into the market new types of resources (e.g., hydro, solar, wind) with production patterns that vary by time of day, geographic location, and season.

To date, the announced participants of the EDAM include the CAISO, PacifiCorp, LADWP, PGE, IPCO, and most of the BANC BAA, including SMUD. This footprint contains a diverse set of resources, including wind, solar, and hydro facilities that are spread over a geographically large region from Wyoming to Washington to Southern California.[17] For example, PacifiCorp itself already owns wind resources in Wyoming, Montana, Oregon, and Washington, and is developing additional resources across its service territory, while the CAISO footprint includes some of the best solar resources in the U.S.

Q. Have these cost savings associated with the EDAM been quantified?

A. Yes, I recently led an effort to quantify the benefits of the EDAM on behalf of BANC (including SMUD), Idaho Power Company, LADWP, PacifiCorp, and SMUD. In that study, we found that the EDAM[18] would reduce customer costs by approximately $430 million/year for CAISO and the five study participants. The EDAM cost savings for PacifiCorp customers were estimated to be over $180 million/year.[19] The reduction in costs for the Company's customers was largely driven by the fact that the EDAM will take the majority of unit commitment and dispatch decision-making out of the Company's hands. The EDAM will provide a market-based signal on optimal operation of the Company's

[17] The geographic and resource diversity of the EDAM would increase if additional members join. The broader WEIM footprint includes significant hydroelectric resources in the Pacific Northwest, additional solar resources in Nevada and Arizona, and wind resources in New Mexico.
[18] The EDAM footprint analyzed in the study included all the listed study participants and the CAISO.
[19] Hannes Pfeifenberger, John Tsoukalis, and Evan Bennett, *Brattle EDAM Simulations: PacifiCorp Results* (Apr. 2023), https://www.brattle.com/wp-content/uploads/2023/04/Brattle-EDAM-Simulations-PacifiCorp-Results.pdf

resources that will take into account more than just the Company's resources and service territory and based on information the Company does not have access to on its own.

A significant share of the estimated cost reductions is driven by the EDAM's ability to export more excess solar power from California to the other market participants, reducing curtailments of renewable energy by 2.4 terawatt hours, filling in during periods of low wind generation in the PacifiCorp BAAs, and reducing the use of the more expensive natural gas-fired generation units in the market footprint.[20] If the EDAM participation expands to include additional utilities, I would expect the magnitude of cost savings and quantity of avoided curtailments to increase as well—all to the ultimate benefit for customers.[21]

In addition, the operational benefits and customer savings from regional markets in the WECC have already been demonstrated by the WEIM, which uses SCED to optimize participating utilities' generation dispatch in a

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[20] *Id.*

[21] Several studies have highlighted the increase in efficient operation of generation resources in a regional market. For example, Stratford Douglas has closely examined the efficiency gains in the utilization of coal-fired power plants between 1981 and 2000. He finds a significant relationship between whether a given plant is dispatched as part of a regional transmission organization ("RTO") and its capacity factor, with efficiency gains of between one percent and three percent in RTO systems as compared to traditionally-organized and regulated systems. Similarly, a study by James Bushnell and Catherine Wolfram suggests that fossil-fuel plants in areas with regional power markets tended to operate slightly more fuel-efficiently, with estimated efficiency gains of around two percent. Seth Blumsack, *Measuring the benefits and costs of regional electric grid integration*, ENERGY LAW JOURNAL, Vol 28:147 (2007).

five-minute real-time energy market and covers a large geographic area encompassing most of the WECC. The WEIM has created more than $5 billion in operational benefits to its members since its inception in 2014. By extending market operations to the day-ahead time frame and adding optimized unit commitment, the EDAM offers additional benefits to member utilities and their customers. This will be particularly true as the EDAM footprint grows to include more of the existing WEIM members.

III. THE IMPACT OF PACIFICORP’S EDAM PARTICIPATION ON THE ECAM

Q. Are you familiar with the ECAM PacifiCorp is subject to in Idaho?

A. Yes.

Q. Please explain your understanding of the ECAM mechanism.

A. The ECAM is a true-up mechanism that provides the Company the possibility of recovering a portion of any differences between the actual net power costs incurred to serve its customers and the forecast base net power costs typically established during general rate case proceedings. ECAM costs include “net power costs” and various other costs and revenues. Net power costs include the sum of fuel costs, wholesale power purchase costs, wheeling costs, net of wholesale sales revenues and other revenues, such as production tax credits.

Base ECAM costs are established in the Company's general rate case filings. The Company forecasts its system-wide net power costs by simulating the operations of all its owned and contracted generation resources across all its state jurisdictions, along with estimates of market purchases and sales for the future test year. The Company-wide ECAM costs are then allocated to Idaho customers (and other PacifiCorp customers) based on their share of Company-wide forecast load. The forecast cost per kilowatt-hour ("kWh") of load for Idaho customers becomes the basis for the power supply expense component Company's retail rates, and any deviation of actual costs from the forecast costs is subject to potential recovery or refund under the ECAM.

The difference between base and actual ECAM cost per kWh, both multiplied by the Company's actual retail load in Idaho, is the amount eligible for sharing under the ECAM. The current ECAM includes a 90/10 percent sharing band, meaning customers are responsible for 90 percent of the NPC differential and the Company is responsible for the other 10 percent.

Q. How will participation in the EDAM change the operation of the Company's generation and transmission assets and the net power costs for its customers?

A. As explained above, the EDAM will substitute and improve upon the operational aspects of unit commitment, dispatch, and short-term trading conducted by the Company. As explained above, EDAM does this by utilizing a SCUC and SCED to make optimal commitment and dispatch decisions for all the generation resources in the footprint, leveraging a more complete information set, utilizing the full physical transmission capability of the EDAM participants, and exploiting the generation and load diversity of the regional market footprint.

The unit commitment, dispatch, and trading functions are mostly performed by the Company on its own today for the more limited sphere of its own generation resources and apparent opportunities for bilateral trading with neighbors, each of which is also operating based on its own forecasts for load and fuel prices and available trading counterparts and contract-path transmission capacity.[22] Instead, once in EDAM, the Company will simply submit its load forecasts to the market operator, bid its

[22] In WEIM, real-time dispatch and certain unit commitment for the Company's resources is solved as part of a regional market. The EDAM will extend the function of the WEIM to other time horizons, additional resources, and more transmission assets.

generation resources into the market based on its fuel price and operating cost forecasts, and make available its transmission assets and contracts.

The EDAM will then automatically determine on an hourly, day-ahead basis when it is advantageous for the Company to operate one of its generating resources, subject to operational and transmission constraints, to serve its own load or sell power to other EDAM participants. Similarly, the EDAM will determine when it is economic and feasible to reduce production from the Company’s generation assets and buy power from the market. These day-ahead energy transactions between the Company and other EDAM participants will be automatically scheduled when the hourly trades reduce costs.

In this way, the EDAM will reduce the Company’s net power costs as much as is feasible through day-ahead hourly sales and purchases with other EDAM members, without requiring the Company to find and execute profitable bilateral trading opportunities on its own. In fact, the EDAM will greatly reduce the amount of bilateral market purchases and sales the Company needs to (and can) make on its own. As the EDAM footprint grows, there will be fewer opportunities for the Company’s power marketers to execute more profitable day-ahead energy transactions, as the EDAM will automatically identify the most valuable transactions on behalf of the Company.

Q. Please explain the implications of EDAM participation on the Company's opportunity to find and bilaterally execute purchases and sales that lower net power costs for customers.

A. As I described, the EDAM is designed to find the lowest cost outcome possible given the available generation resources in the market and the physical or contractual transmission on the grid—subject to various operational constraints. This will automatically lower the Company's net power costs as much as possible, given the boundaries of the market and the operational limits of the generation and transmission resources in the market. After the EDAM is implemented, the Company will still have the opportunity to execute bilateral transactions, but those opportunities will be much more limited relative to what the Company can do today.

Given the EDAM's ability to achieve low-cost outcomes, other utilities in the EDAM are unlikely to have the incentive to transact with PacifiCorp outside the market. Nor would it be prudent, in most instances, for the Company to ignore the market solution and execute different bilateral day-ahead transactions with other EDAM members, which would risk a higher-cost outcome for customers than the transactions the EDAM would produce. Therefore, opportunities to pursue economic energy transactions will likely be limited to transactions with non-EDAM members or, in rare instances, to bilateral transactions with other EDAM members executed outside the day-ahead market.

Q. How does EDAM participation change the effectiveness of ECAM incentives designed to motivate the Company to reduce its net power costs for customers?

A. In effect, the EDAM takes the majority of unit commitment and dispatch decision-making out of the Company's hands and provides a market-based signal on optimal operation of the Company's resources, taking into account much more than just the Company's resources and service territory and bilateral trading opportunities.

Even if it were motivated by strong financial incentives, it is unlikely the Company would be able to find a lower-cost outcome for customers than what the EDAM will provide. Given that situation, any variances that do arise between the base rates and the realized costs should not be regarded as something that could be controlled or should have been mitigated through more active market activity by the Company. Correspondingly, *there is no longer any benefit to trying to incentivize such non-productive efforts or activity through ECAM risk-sharing of the variances*.

In other words, there is no benefit in providing financial incentives for outcomes the Company no longer controls. Financial incentives, for the Company will not change how the EDAM operates, which is already designed to lower costs as much as possible given the constraints on the system. Given that the Company will likely not be able to profitably deviate from the EDAM's operational solution for the benefit of customers, maintaining the existing incentives would simply tax the Company for unexpectedly higher costs in the market (something the Company cannot control) relative to anticipated costs at the time the Company initially forecast net power costs. This would increase the financial risks imposed on the Company with no benefit for customers.

Similarly, financial incentives that are compensatory for the Company when net power costs are lower than forecast, will not change how the EDAM operates, nor would they be rewarding the Company for success it actually found or accomplished. Instead, such compensatory incentives would simply reward the Company for lower-than-expected costs in the market as a matter of pure luck.

Q. Does participation in the EDAM mean the Company is sacrificing operational control over its generation and transmission assets?

A. No. The Company will remain the operator of all its generation and transmission resources and will remain the BAA[23] for the same service area it is responsible for today. Ultimate operational control and responsibility for its system of generation and transmission will remain with the Company. While the EDAM will provide a regionally-optimized commitment and dispatch solution for the Company's resources that creates a lower-cost outcome for customers, it will not change the Company's operational control and system-balancing responsibilities.

Furthermore, participation in the EDAM is voluntary. At any time in the future, if the Company or the Commission determined that participation is having adverse effects on costs, customers, or system reliability, it can exit the market.

[23] NERC defines BAA as "The collection of generation, transmission, and loads within the metered boundaries of the Balancing Authority. The Balancing Authority maintains load-resource balance within this area" in its Glossary of Terms updated on December 1, 2023 and found at https://www.nerc.com/pa/Stand/Glossary%20of%20Terms/Glossary_of_Terms.pdf. The NERC definition of Balancing Authority is "The responsible entity that integrates resource plans ahead of time, maintains Demand and resource balance within a Balancing Authority Area, and supports Interconnection frequency in real time."

Q. Please explain how membership in the EDAM impacts the Company's ability to forecast net power costs.

A. Participation in the EDAM will make it more challenging to forecast net power costs than it is today. In the EDAM, net power costs will be determined by a mix of resources, loads, and market conditions that extend much beyond the PacifiCorp system. To keep up with this larger market footprint, the Company would no longer need to forecast fuel costs, generation and transmission outages, renewable production, weather, market prices, and load just for its own resources and service territory—it would need to forecast these variables for the entire EDAM footprint to accurately predict purchases and sales in the market and prices and the Company's net power costs resulting from EDAM transactions in that footprint. Because much of that data is unavailable publicly, it will be more difficult for any individual EDAM participant to accurately forecast the outcomes of the market.

For example, the recent effort I led to calculate the benefits of the EDAM for BANC, Idaho Power, LADWP, PGE, PacifiCorp, NV Energy, and SMUD illustrates the inability for any one EDAM participation to accurately forecast the operations of the entire regional market. To complete that study, my team collected non-public data and information from all of the study participants and from the CAISO. That data and information included operating costs for all of their resources, load patterns, renewable resource production patterns, transmission rights and availability of transmission for the market for each member, and operational constraints for each study participants' resources and transmission systems. This is information that the EDAM will have access to, through bids or other information provided by market participants. However, no individual utility in the WECC today can access this kind of non-public information for other utilities' systems. Therefore, a forecast of EDAM operations and market outcomes made by any individual utility will be inaccurate, simply due to a lack of the necessary information on other market participants.

Q. How does the Company's participation in the EDAM change the need for risk sharing in the ECAM?

A. Due to the Company's participation in the EDAM, there is no need for and no benefit to customers from risk-sharing in the ECAM. This makes it advisable to modify the ECAM, remove the incentives it provides for market outcomes the Company will no longer control in the EDAM, and move it closer to the rate adjustment mechanisms used by regulators for the net power cost of utilities participating in regional markets in other states, as discussed in the next section of my testimony.

IV. REVIEW OF FUEL AND NET POWER COST RECOVERY MECHANISMS IN OTHER STATES

Q. Have you reviewed mechanisms used in other states to recover deviations in net power costs, similar to the ECAM?

A. Yes. I have compiled information on the current policies on cost recovery for vertically integrated utilities across several states. My review excluded restructured states in which utilities have divested their generation resources, thereby serving customer loads through deregulated merchant generation. For instance, this means that Texas utilities in the Electric Reliability Council of Texas are excluded from my review as they are not a relevant comparison with the market structure in Idaho as applicable to PacifiCorp. Similarly, the vertically divested utilities in most of the Mid-Atlantic, New York, and New England states are not included for the same reason. The situation for PacifiCorp in Idaho is more like that of the vertically integrated utilities in the Midcontinent Independent System Operator and the Southwest Power Pool, which are included in this review. In total, I reviewed the rate adjustment clauses applicable for new power costs across 35 states that have vertically integrated utilities. The results of my survey, detailing the structure of each state’s adjustment clauses is attached as Exhibit No. 30.

Q. Based on your review, is the Company's existing ECAM consistent with those of comparable electric utilities around the country?

A. No. Of the 35 relevant states I reviewed, the vast majority do not apply any risk sharing mechanisms modifying utility cost recovery. Instead, the vast majority fully pass through power costs to customers. Only a minority of comparable states apply risk-sharing mechanisms.

These findings are summarized in Figure 2. Of the 35 relevant states I reviewed, 26 have a no risk sharing structure in place and fully pass through any true-ups to balance discrepancies between forecast and realized net power costs.[24] The remaining nine states employ some variant of risk sharing. Among Idaho utilities, Idaho Power Company (IPCO) has less risk sharing than does PacifiCorp, with 95 percent of the variance between IPCO's forecast and actual operating costs getting passed through to ratepayers. More information on the structures in other states can be found in Exhibit No. 30.

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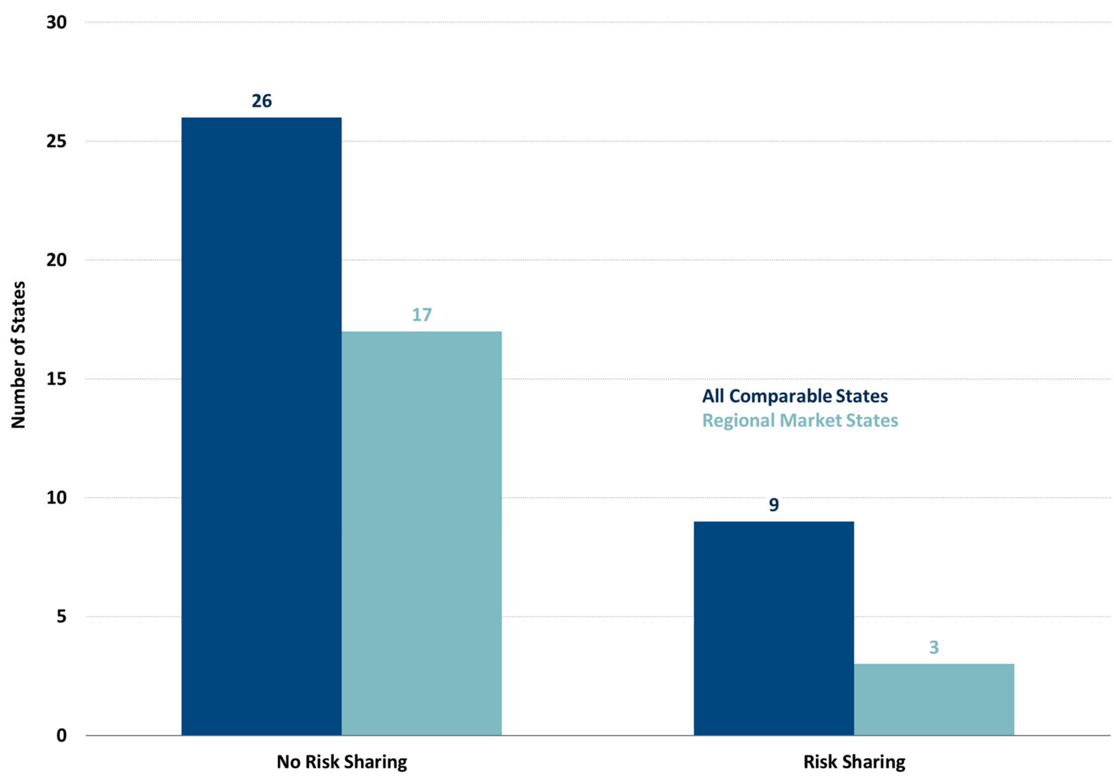
[24] Wisconsin is an exception among these 26 states in that it employs a 2% deadband to modify the cost deviations from forecasts that are eligible for a full passthrough to customers. Any operational cost overruns or savings within 2% of the forecast become the responsibility of the state's utilities to pay, while deviations above 2% are fully passed through to ratepayers.

Figure 2: Incentive Structures in Net Power Cost Adjustment Mechanisms in other States



Source and Notes: Based on review of fuel adjustment clauses or related mechanisms in S&P Global's Energy Regulatory Research Associates summaries and utility filings.

Q. Does the same result hold true for the subset of states with vertically integrated utilities that participate in regional power markets?

A. Yes. The vast majority of comparable participating in wholesale power markets in comparable states to Idaho have a complete pass through of net power costs. Of the 35 states with vertically integrated utilities, 20 operate wholly or partially in RTO/ISO regional markets and, of those 20, only three (Missouri, Montana, and Vermont) do not have complete pass through of net power costs.

V. CONCLUSIONS

Q. Please summarize your conclusions.

A. Based on the impact of EDAM participation on the Company's operation and my review of net power cost-related rate adjustment mechanisms in other states I conclude the following:

- The EDAM will reduce customer costs by utilizing a SCUC and SCED to make optimal commitment and dispatch decisions for all the generation resources in the footprint, leveraging more complete information on generation costs, expected load, expected renewable generation, and transmission availability, utilizing the full physical transmission capability of the EDAM participants, and exploiting the generation and load diversity of the regional market footprint.

- The Company will have limited ability to improve upon the market outcome determined through the EDAM, implying limited ability to further reduce net power costs for customers beyond the improvement already achieved through EDAM.

- Due to the Company's participation in the EDAM, there is no need for and no benefit to customers from the incentives included under the current ECAM in Idaho. These incentives will not change how the EDAM operates, nor will the Company have the ability to respond to these incentives.

- The current incentive structure in the ECAM is inconsistent with similar mechanisms for net power cost-related rate adjustments used in comparable states.

- It is advisable for the Commission to amend the ECAM to align with the net power cost-related rate adjustment mechanisms applied in other states, recognizing the impact of EDAM participation on the Company's ability to influence net power costs.

Q. Does this conclude your direct testimony?

A. Yes it does.

Case No. PAC-E-24-04
Exhibit No. 29
Witness: John Tsoukalis

BEFORE THE IDAHO PUBLIC UTILITIES COMMISSION

ROCKY MOUNTAIN POWER

Exhibit Accompanying Direct Testimony of John Tsoukalis

Resume of John Tsoukalis

May 2024

John H. Tsoukalis

PRINCIPAL

Washington, DC 1 (202) 527-0219 John.Tsoukalis@brattle.com

Mr. John Tsoukalis is a Principal at The Brattle Group specializing in electric power sector economics, modeling, and regulation. His expertise includes analyzing and designing alternative transmission rate designs, assessing the effectiveness of transmission planning processes and designing improvements to planning processes, and conducting benefit-cost analyses of generation and transmission infrastructure. He is experienced in assessing the value of transmission rights, analyzing the effectiveness of transmission cost allocation processes, and helping transmission developers to analyze investment opportunities in the US and Canada. His experience extends to conducting nodal production cost and power flow simulations of wholesale markets and regional power systems.

His work has been used to assess the benefits of transmission infrastructure, participation in wholesale power markets, joint regional unit commitment and/or dispatch, and consolidated balancing area operations. He has conducted production cost simulation models to value regional transmission infrastructure and trading rights, assessed the operation of regional transmission systems, analyzed the operation and value of generation assets in bilateral and organized regional power markets, and for the assessment of potential market manipulation and market power abuse in wholesale power markets.

Mr. Tsoukalis has worked with Independent System Operators (ISOs), Regional Transmission Organizations (RTOs), cooperatives, public power authorities, and investor-owned utilities on a wide range of issues related to wholesale power markets. He is experienced in helping ISOs/RTOs and utility clients analyze and design market rules to increase the efficiency of existing wholesale market operations, including the design of transmission charges, operating reserve products, and market power mitigation rules and procedures.

He has testified before the U.S. Federal Energy Regulatory Commission (FERC) and the Alberta Utilities Commission (AUC) in matters related to transmission rate design, transmission cost allocation, and transmission rate cases. He has testified in U.S. District Court in a dispute related to emergency wholesale market transactions. He has provided expert opinions to FERC related to the development and improvement of effective regional transmission planning and cost allocation processes, as well as the efficient design of ancillary services. His work on market design and the simulation of wholesale power markets has been filed with FERC and U.S. state regulatory authorities, and he has supported the development of testimony in front of FERC and state regulatory authorities to assist with the design of ancillary service products, the appropriate tariff provisions to allow for adequate cost recovery, and to help develop tests for identifying and mitigating potentially manipulative behavior.

AREAS OF EXPERTISE

- Benefits and costs of wholesale power markets and regional coordination
- Production cost modeling
- Market design in wholesale power markets
- Analysis of GHG policy and implementation in wholesale markets
- Transmission rate design and cost of service studies
- Transmission cost-benefit analyses
- Electric utility strategic planning
- Resource planning and asset valuation
- Market manipulation detection and damages analysis
- Analysis and mitigation of market power
- Competitive transmission

EDUCATION

- **Universitat Autònoma de Barcelona**, **Spain**
  M.Sc. in Economic Analysis, 2012
- **Barcelona Graduate School of Economics, Spain**
  M.Sc. in Economics, 2010
- **Washington and Lee University**
  B.A. in Economics with Honors, 2006

PROFESSIONAL EXPERIENCE

Power System Modeling

- **Analysis of the Benefits and Cost of Membership in the Proposed Extended Day-Ahead Market (EDAM) and Markets+.** On behalf of several utilities in the western U.S., simulated the benefits and costs of participation in the two proposed regional day-ahead markets in the WECC. Simulated the existing bilateral markets in the WECC, including block trading at the major hubs in the region, intertie trades at the existing RTO seams, and existing real-time imbalance markets. Simulated important market design features of the proposed day-ahead markets, including the use of transmission rights in the markets, the market structures used to restrict and price imports into states with GHG pricing regimes, and the accounting and allocation of congestion revenues collected by the markets. Presented results of the analysis to seven different state commissions in the WECC.
- **Valuation of Generation Asset in the Bilateral Power Markets in Florida.** On behalf of an independent power producer, developed a market simulation and resource planning model of the Florida power system. Analyzed the value of a new gas-fired generation resource in Florida in the existing bilateral market structure in the state and under various assumptions on future resource costs. Calculated unit-level operation for a new gas-fired resource and determined the net present value of the asset.
- **Analysis of Benefits and Costs of Market Reforms for Customers in South Carolina.** On behalf of the South Carolina legislature, analyzed the benefits and costs to customers of numerous different market reform options for the state, including wholesale, retail, and system planning reforms. Developed a customized model, with input and data from a group stakeholders, of the entire Southeastern U.S. including the Carolinas, Southern Company, all of the Florida utilities and cooperatives, TVA, PJM, and MISO. Simulated the Southeast Energy Exchange Market (SEEM) and the other bilateral markets that existed through the Southeastern U.S. and compared the operation of those markets to various types of potential wholesale market designs and footprints.
- **Analysis of Extended Day-Ahead Market (EDAM) in the WECC.** On behalf of a group of utilities in the WECC, simulated the proposed Extended Day-Ahead Market (EDAM) and estimated the benefits of the joint unit commitment and dispatch, pooled transmission rights, and reserve sharing and joint provision under the proposed market structure. Represented the proposed GHG-accounting structure in the EDAM market footprint for transactions across states with GHG policies and states without policies. Represented the bilateral markets in the WECC, including utility-specific unit commitment and dispatch

decision-market, trading hubs, block trading, trading margin requirements, wheeling fees, and limited transmission rights/transfer capability between utilities. The bilateral market was compared to the regional market case to estimate benefit metrics.

- **Analysis of Operation of Proposed Wind Farm in Colorado.** On behalf of a renewable developer in the WECC, analyzed the patterns of congestion and curtailments in the Colorado-Wyoming region. Simulated operation of a proposed wind farm under the existing bilateral markets and real-time imbalance markets, and under the proposed SPP West RTO market. Determined exposure to congestion and curtailment risk for the proposed wind resources.
- **Analysis of Generation Resource Investment and Retirement Decision in Alberta.** On behalf of a generation owner in Alberta, simulated investment, retirement, and operational outcomes for the Alberta power pool through 2050. The analysis used Brattle's GrimSIM capacity expansion modeling software to determine the profitability of various generation resource types, prices in the AESO market, investment decisions in new resources, and retirement decisions for existing resources. The analysis accounted for the proposed federal decarbonization policies. Analyzed the change in resource mix in the province needed to comply with proposed policies, operational outcomes for client-owned generation assets, pool prices in the province, and the impact of new generation assets on the exercise of market power on pool prices.
- **Analysis of Market Participation Benefits.** On behalf of a group of cooperatives, municipal utilities, and federal power authorities in the WECC, simulated the benefits of joining the proposed Southwest Power Pool (SPP) West RTO. Modeled the bilateral markets in the region and the joint unit commitment, economic dispatch, optimization of the DC ties between SPP and the WECC, and then pooled reserve procurement under the proposed SPP West RTO.
- **Analysis of the Western Energy Imbalance Service and SPP West RTO.** On behalf of the Southwest Power Pool, conducted a production cost simulation of the Eastern Interconnection and WECC to assess the benefits from creating the Western Energy Imbalance Service (WEIS) and from extending the SPP RTO market into portions of the WECC. Analyzed how transmission systems would operate under the new market structure, including the DC interties that connect the Eastern Interconnection and the WECC and the transmission systems in both interconnections. Calculated benefits for market participation for the utilities interested in joining the new market and for the existing utilities in SPP.

- **Analysis of Participation in Regional Energy Imbalance Markets.** On behalf of Black Hills Corp., Colorado Springs Utilities, Platte River Power Authority, and Xcel Energy, analyzed the production cost benefits from participation in the CAISO-administered Western Energy Imbalance Market and the proposed SPP-administered Western Energy Imbalance Service. Conducted several production cost simulations testing multiple scenarios and wrote report summarizing procedure and findings. The report was filed with the Colorado PUC in a proceeding to explore market participation for Colorado utilities.
- **Analysis of Participation in Regional Energy Imbalance Markets.** For an investor-owned utility in the western U.S., estimated the benefits of participating in an energy imbalance market. Simulated membership in two energy imbalance market options and analyzed the relative gains from each option.
- **Analysis of Regional Market Alternatives for the Mountain West Transmission Group.** For the eight members of the Mountain West Transmission Group in Colorado, Wyoming, and neighboring states analyzed the costs and benefits of alternative regional transmission and market options. The regional transmission and market analysis included detailed market simulations and estimation of member costs and benefits for (a) retaining the current bilateral market construct; (b) forming a regional transmission group with de-pancaked transmission service; and (c) forming or joining a full “Day 2” regional wholesale power market. The results informed the clients’ decision to explore regional market alternatives with existing RTOs.
- **Analysis of Resource Planning Options.** For a municipal utility in the western U.S., simulated system operations and estimated production costs under several potential future resource portfolios and potential market participation scenarios under consideration by the utility. Results were relied upon by the utility to inform resource planning and market participation decisions.
- **Analysis of Participation in a Regional Wholesale Power Market.** For a group of electric cooperatives, public power authorities, and investor-owned utilities in the western U.S., estimated the benefits of participating in a regional wholesale power market. Simulated membership in a proposed regional wholesale power market under different potential future scenarios and estimated the benefits from participation for each member in the group. Results of the simulations, including the estimated benefits of membership in the market, were relied upon to inform the clients’ decision making regarding joining the proposed market.

- **Valuation of Strategic Investments.** For a private equity firm, estimated the long-term value of two generation assets owned by the firm. Simulated energy revenues for the generation assets under multiple future scenarios to consider the impact of energy policy changes, renewable energy penetration, fuel price changes, and participation in regional wholesale powers markets.

Transmission Benefits Analysis, Rate Design, and Investment

- **Testimony in Transmission Rate Recovery Proceeding.** On behalf of New York Transco LLC, provided expert testimony in front of the Federal Energy Regulatory Commission (FERC) analyzing the case for transmission incentives for the Propel NY Energy project. Assessed recent FERC Orders granting transmission incentives (Construction Work in Progress in Rate Base, Project Abandonment, and ROE Incentive Adders) and compared the risk profile of the Propel NY Energy projects against projects that have been awarded similar incentives. Provided a review of FERC precedent and legislative mandate for transmission incentives and established the benefits of transmission incentives for customers and transmission developers.
- **Transmission Benefit-Cost Analysis in the WECC.** On behalf of a utility in the WECC, analyzed the benefits of proposed transmission infrastructure. Simulated power markets in the western U.S. to determine the customer savings created by the new transmission infrastructure. Calculated the following benefit and cost metrics: reduced fuel costs, lower operating costs, emissions reductions, the increased sale of short-term transmission service, higher congestion revenues allocated from regional wholesale power markets, higher bilateral trading profits for the utility, job and economic stimulus impacts of the investment, avoided generation interconnection costs, avoided or deferred reliability investments and upgrades, resource adequacy benefits. Presented findings to the state commission.
- **Analysis of Net Power Cost Pass Through Mechanism.** On behalf of an electric utility in the WECC, analyzed the net power cost pass through mechanisms imposed by their state commission and assessed how participation in a regional day-ahead wholesale power market would influence the utility's ability to reduce net power costs for their customers, including the impact of security constrained unit commitment (SCUC) and security constrained economic dispatch (SCED) on optimizing the operation of the client's generation and transmission assets. Compared the net power cost pass through mechanisms the client is subject to with mechanisms in states with a similar regulatory and market construct.

- **Assessment of a Utility's Power Market Model used for Net Power Cost Forecasting.** On behalf of an electric utility in the WECC, reviewed their internal models of wholesale market markets in the region and helped them assess how accurately their modeling captures the dynamics of the existing bilateral markets in the WECC and proposed regional day-ahead markets. The analysis was used to inform their net power cost filings with their state commission and to assist utility leadership in making decisions on membership in proposed regional wholesale power markets.
- **Analysis of Local Network Service Transmission Rates in ISO-NE.** On behalf of a generation owner in ISO-NE, analyzed the rate they pay for local network service and helped them determine the key drivers for recent rate increases. Assisted the client in developing strategies for mitigating their transmission rates in the future.
- **Analysis of Market for Rights on a Proposed Transmission Asset and Support of Application for DOE Funding.** On behalf of a transmission developer in the WECC, supported their winning application for funding under DOE's Transmission Facilitation Program. Prepared an analysis of market benefits for the proposed transmission line, including an assessment of demand for rights on the line and likely off takers. Presented results to DOE in a written report and responses to DOE questions, as well as in-person at final round interviews with DOE staff. The project was ultimately selected by DOE based on the likelihood that the project would be developed and that the rights purchased by DOE would be successfully re-sold.
- **Transmission Benefit-Cost Analysis for Proposed Transmissions Assets in the WECC.** On behalf of an investor-owned utility and independent transmission developer in the WECC, analyzed the benefits and costs of a proposed portfolio of transmission projects. Simulated the bilateral power markets in the region and the WEIM and analyzed the cost of renewable energy resources that can be integrated through the new transmission compared to higher-cost resources that would be developed with the new transmission. Calculated multiple benefit and cost metrics for the proposed transmission assets, including adjusted production cost, emissions reductions, resource adequacy benefits, reduced congestion, and avoided or deferred reliability upgrades.
- **Transmission Benefit-Cost Analysis for Proposed HVDC Transmission Line between SPP and the WECC.** On behalf of a merchant transmission developer, calculated numerous benefit and cost metrics for a proposed 100-mile HVDC line with a capacity of 3,000 MW that would connect the SPP RTO with major trading locations in the WECC. Simulated the SPP RTO market and the proposed day-ahead regional power markets in the WECC to assess the benefits of the proposed project. Calculated numerous benefit metrics for the proposed

line, including adjusted production cost, emissions reductions, resource adequacy benefits, reduced congestion, and avoided or deferred reliability upgrades.

- **Transmission Benefit-Cost Analysis for Proposed HVDC Transmission Line between SPP and MISO.** On behalf of a merchant transmission developer and an investor-owned utility, calculated numerous benefit and cost metrics for a proposed 400-mile HVDC line that would connect the SPP and MISO markets. Simulated the SPP and MISO RTO markets to assess the benefits of the proposed project. Calculated numerous benefit metrics for the proposed line, including adjusted production cost, emissions reductions, resource adequacy benefits, reduced congestion, and avoided or deferred reliability upgrades.
- **Testimony in Transmission Rate Design Proceeding.** On behalf of Capital Power, provided expert testimony in front of the Alberta Utilities Commission (AUC) analyzing the impacts of a proposed new transmission tariff design provided by the Alberto Electricity System Operator (AESO). Analyzed the increase in uneconomic bias caused by the proposed tariff design and cost shifting to other customers in the province. Provided written and oral testimony in front of the AUC.
- **Testimony in Support of Transmission Rate Case Filing.** On behalf of Portland General Electric, provided testimony before the FERC in support of their transmission rate case. Testimony supported the transmission cost of service study filed as part of the rate case and provided explanation on key input and components of the cost-of-service study, including the drivers of change in the company's costs service.
- **Testimony in Transmission Cost Allocation Proceeding.** On behalf of GridLiance High Plains LLC, provided testimony before the FERC on the benefits of transmission assets. Conducted a shift factor analysis to determine how the assets are used to support regional power transfers. Analyzed transmission contingencies to assess if the assets alleviated system overloads under contingency conditions.
- **Testimony in Transmission Cost Allocation Proceeding involving the Seven Factor and Mansfield Tests.** On behalf of GridLiance High Plains LLC, provided testimony before the FERC applying FERC's Seven Factor Test and Mansfield Test to a set of assets the company was seeking to place in the SPP regional transmission tariff. Applied shift factor and electrical distance analysis to determine how the integration of the assets the relevant zone of SPP. Testimony resulted in a favorable initial decision from the FERC Administrative Law Judge.
- **Design of Transmission Access Charges.** For the California ISO, developed an analysis of cost shifts between participating transmission owners due to different Transmission Access

Charges (TAC) structures. Results of the analysis were used by the CAISO in stakeholder engagement during an initiative aimed at re-designing the TAC.

- **Strategic Transmission Planning and Rate Analysis.** For an integrated electric utility client, analyzed the qualitative and quantitative benefits of participating in a joint transmission tariff with interconnected transmission owners. Analyzed the impact on transmission rates for this utility. Identified and assessed additional regional integration options for this utility client, including participation in an existing energy imbalance market, membership in an adjacent RTO, and the development of new regional markets with interested neighbors.
- **Transmission Investment Opportunities Assessment.** For several transmission owners and developers, projected the investment need for transmission infrastructure over the next ten years in all U.S. planning regions. Provided analysis of the different drivers of this investment need and studied the implementation of competitive bidding processes for transmission projects as mandated by FERC Order 1000. Helped create forecasts on the amount and type of competitively sourced transmission investment in each planning region across the U.S.
- **Analysis of the Benefits of Transmission Investment.** For an investor-owned utility, analyzed the reliability and economic impact of over $3.5 billing in capital expenditures to upgrade and harden their existing transmission assets. The reliability benefits analysis estimated a reduction in lost load due to the transmission investments and applied a value of lost load to the reduction. The economic benefits analysis relied on an input-output model analysis to determine the economic activity, job creation, and tax revenues generated by the upgrades to existing transmission facilities. The results of the analyses were used to support internal decision making on capital expenditures and for discussion purposes with policy makers in the states where the utility operates.
- **Analysis of the Benefits of New Transmission Assets.** For an investor-owned utility, analyzed the economic impact of investing in a new transmission line. The analysis relied on an input-output model analysis to determine the economic activity, job creation, and tax revenues generated by the construction of the new transmission facility. The results were used in testimony in front of two state regulatory commissions.
- **Competitive Transmission Opportunity Assessment.** On behalf of a competitive transmission developer, assessed the opportunity for competitive transmission projects. Analyzed transmission investment needs in each region of the U.S. and reviewed the transmission planning processes and competitive project requirements in each region. Conducted a focused analysis of competitive opportunities in several RTO markets.

- **Analysis of Transmission Rate Design.** For a transmission owner in an ISO market, analyzed the performance of the transmission rate design based on criteria established by the market administrator. Developed alternative rate design proposals for use in the public stakeholder process.
- **Long-Term Transmission Planning.** Supported the development of testimony filed on behalf of a regional transmission planning entity in front of a state regulatory commission. Analyzed the forecasts and model utilized by the planning entity to recommend specific transmission projects. Provided guidance to the commission on the reasonableness of the process implemented by the planning entity relative to industry practices.
- **Evaluation of a Transmission Utility.** For a potential investor, contributed in the effort to evaluate a transmission utility. Helped estimate the size of future rate base through a study of proposed transmission projects within the utility's service territory. Leading to an assessment of the likelihood each project would get regulatory approval and ultimately be built and contribute to rate base.
- **Retail Electric and Water Rate Design.** For a municipal electric and water utility in the western U.S., reviewed utility's electric retail rate structure and retail water rate structure. Conducted benchmarking study against similarly positioned electric and water utilities in the region. Provided recommended changes to the rate structures for both water and electric power. Analyzed the rate impact of incorporating on new water customers for existing water customers.

Wholesale Market Design

- **Expert Report in U.S. District Court in Contract Dispute Related to Bilateral Transactions at Southwest Power Pool (SPP) Seam.** On behalf of an electric cooperative, provided expert report in front of a U.S. District Court. Analyzed the cost of providing bilateral energy sales at the SPP market seams compared to the revenues.
- **Wholesale Market Price Formation and Fast-Start Resource Integration.** For an SPP market participant, analyzed inefficiencies in wholesale price formation and the commitment and dispatch of fast-start resources. Worked with client and SPP teams to developed recommendations and presented them in an affidavit before the FERC.
- **Ramping Product Design.** On behalf of an SPP market participant, drafted a white paper on efficient and effective methods and best practices for designing an ancillary service product to procure ramping capacity. Collaborated with SPP staff and the SPP market monitor to

develop the best design principles for the ramping product and to integrate that product into SPP's existing day-ahead and real-time energy and ancillary services markets.

- **Design of Ontario Market Power Mitigation Regime in Capacity Auction.** For the IESO, developed methodology for calculating the resource-specific offer caps to be used as part of the market power mitigation regime in the Capacity Auction in Ontario. Public report was issued with recommended approach for use in the stakeholder process and to inform public discussion on the offer cap design.
- **Capacity Auction Design.** For an ISO client, analyzed proposed auction design and provided recommendations on improving the design. Tested the auction clearing and price formation mechanisms to ensure optimal outcomes are achieved and efficient prices are produced from the auction. Provided several recommended changes to the clearing mechanism and price formation procedure, which were utilized by the client to improve the auction design.
- **Financial Transmission Rights (FTRs) Market Design.** For an ISO client, reviewed the existing transmission rights market in the region and developed recommendations for amending FTR market design, including an examination of whether the FTR market provided benefits for load in the region.
- **Ontario TR Market Design.** On behalf of the IESO, reviewed experiences in other regional markets and advised IESO staff on the methodology for allocating surplus congestion rents and TR auction revenues. Co-authored a public report with recommendations on updating the method for distributing congestion account surplus to Ontario market participants.
- **Alberta Capacity Market Design.** On behalf of the AESO, collaborated with AESO staff to develop features of the proposed forward capacity market for Alberta.
- **Ontario Capacity Market Design.** On behalf of the IESO, advised IESO staff on the design of the proposed forward capacity market for Ontario.
- **Assessing the Impact of Dynamic Pricing.** For a regional transmission organization, analyzed the impact of different dynamic rate designs on their system. Focused on determining the reduction in peak load and total energy consumption. Estimated the monetary benefits derived from those reductions. Presented results and the models utilized to internal stakeholders.

Analysis of Clean Energy Markets, Decarbonization Policy, and Environmental Regulation

- **Analysis of the Market for Clean Energy in the WECC.** On behalf of a utility in WECC, analyzed the bilateral market for clean energy in the western U.S. with specific focus on the Pacific Northwest region. Assessed the planned clean energy resources in the western U.S. and compared against the projected demand for clean energy based on state policies. Calculated an hourly supply of available clean energy, defined as clean energy production that is not claimed by any other load-serving entities to comply with their state policies. Determined a premium for clean energy in each hour relative to bilateral market power prices.
- **Analysis of Proposed U.S. Treasury Rules for Hydrogen Tax Credits.** On behalf of Los Angeles Department of Water and Power, analyzed the proposed regulations (Section 45V rules) on the clean hydrogen production tax credit established by the Inflation Reduction Act (IRA). Assessed how the proposed rules align with the operation of power markets and typical resource planning practices in the western U.S. Proposed alternative approaches for the U.S. Treasury to consider that would reduce compliance cost and ensure qualifying hydrogen production would be clean. Developed a white paper that was filed as part of LADWP's comments on the proposed rules.
- **Simulation of Wholesale Market GHG Rules in the WECC.** On behalf of several utilities in the western U.S., modeled the proposed GHG market rules in EDAM and Markets+. Simulated the two proposed day-ahead markets and analyzed the operation of both GHG structures on price formation, GHG emissions, and transfers into GHG-pricing states under each market.
- **Analysis of Clean Energy Supply and Demand in British Columbia.** On behalf of a natural gas producer in British Columbia, analyzed the likely demand for clean energy resources in the province considering decarbonization policies and projected electric load growth. Assessed the economic and technical potential to develop various types of clean energy resources in the province, including the cost of new clean energy resources. The results of the analysis were used by the client to assess the potential to electrify their natural gas production operations in the province, including a potential new liquified natural gas export facility.
- **Simulation of Alberta Power Market under Proposed Federal GHG Reduction Policies.** On behalf of a generation owners in Alberta, simulated investment and operational outcomes for the Alberta power pool through 2050 accounting for proposed federal GHG reduction policies. Analyzed the change in resource mix in the province needed to comply with proposed policies, operational outcomes for client-owned generation assets (and other

asset-types in the province), pool prices in the province, and the impact of new generation assets on the exercise of market power on pool prices. Supported client in discussions with federal policy makers.

- **Analysis of Market Participation Benefits under GHG Policies.** On behalf of a cooperative in Colorado, simulated participation in the SPP West RTO under the proposed Colorado GHG policy. Simulated the dispatch cost of GHG in Colorado resources, and the cost of importing generation from out-of-state emitting resources in both a bilateral market setting and the RTO setting.
- **Analysis of Proposed EPA GHG Standards.** For a group of utilities in the WECC, analyzed the impact of the proposed rule on their generation assets, reviewed alternative compliance paths with the utility subject matter experts, and assisted in the preparation of the comments to be submitted to EPA.
- **Review of GHG Accounting Mechanisms in the WECC.** For WEST Associates, a group of utilities in the WECC, cataloged the GHG and clean energy accounting methodologies in use across the western U.S., including RPS, energy supply disclosures, GHG reporting and reduction rules, and voluntary reporting. Wrote a white paper presenting the findings.
- **Analyze of Market Options for Clean Power in the WECC.** On behalf of a renewable developer in the WECC, assessed the market opportunities for their wind farms after existing PPAs expire. Analyzed future market prices at different potential points of sales (e.g., the AESO market, Mid-C, the CAISO market). Provided information on potential operational hurdles and costs for bring their wind power to market under different strategies. Assessed the potential for coupling wind power with local hydro resources to deliver a firm clean energy product, and the market premium for that product relative to an energy only PPA.
- **Environmental Regulation Impact.** For a merchant power producer, assessed the impact of changes in the regulatory environment on the economic viability of coal-fired generation, particularly focused on the Mercury Air Toxics Standards (MATS) rule.

Resource Planning and Asset Valuation

- **Analysis of British Columbia Hydro and Power Authority's Resource Plan.** On behalf of a large power customer in British Columbia, analyzed the resource plan for BC Hydro including the estimated cost and demand for new resources available in the province. The analysis considered the decarbonization policies and related electrification load growth.

Assessed the potential for developing various types of clean energy resources in the province, including the cost of new clean energy resources.

- **Development of a Renewable Procurement Strategy.** On behalf of an electric utility in Canada, analyzed various options for procuring and delivering clean energy resources to their customers from neighboring provinces and U.S. states. Assisted the client in weighing different economic, development, and political risks related to different procurement strategies and analyzed the likely future supply and demand dynamics for clean energy resources in neighboring. Results of the analysis informed the client's clean energy procurement strategy.
- **Assessment of Reliability Under Deep Decarbonization Scenarios.** On behalf of a utility in MISO, analyzed their resource plan developed to comply with state decarbonization policies. Simulated the operation of their system under deep renewable penetration scenarios and assessed their ability to maintain reliable operation of the system. Results were used to support IRP decision making and as evidence in front of their state commission.
- **Valuation of Generation Assets in the WECC.** On behalf of a merchant generation owner in the WECC, analyzed the market opportunity for two gas-fired combine cycle resources in the bilateral power market in the WECC. Developed a forecast of energy and capacity revenues under different decarbonization policy scenarios and different wholesale market structures in the western U.S. Assessed the potential demand for energy and capacity from the assets based on resource plans of utilities in the region and state decarbonization policies. The results informed the clients power marketing strategy after the expiration of existing PPAs for the assets.

Analysis of Market Manipulation, Compliance, and Wholesale Market Disputes

- **Analysis of Potential Merger in Alberta.** On behalf of a generation owner in Alberta, analyzed the impact on prices from a proposed merger between two major generation owners in the province. Supported client in comments and presentation before the Canadian Competition Bureau.
- **Breach of Contract Dispute related to Wholesale Power Transactions.** On behalf of Associated Electric Cooperative, Inc. (AECI) analyzed the cost of supplying emergency power into SPP during Winter Storm Uri and compared cost with payments received through SPP settlement. Estimated damages in the form of unrecovered costs for producing the emergency power. Prepared an expert report filed in U.S. Federal District Court.

- **Compliance Investigation in New Zealand.** For Meridian Energy, analyzed claims made by other market participants and by the Electricity Authority (EA) alleging an undesirable trading situation (UTS) due to Meridian's behavior, and submitted comments to the EA.
- **Compliance Plans for Generation Owners.** For a generation owner in Europe, assisted in-house compliance team in the development of compliance procedures and rules tailored to the specific offer strategies and forecasting methodologies relevant to their generation fleet.
- **Wholesale Electricity Market Manipulation.** For a generation and transmission cooperative in the Southwest Power Pool (SPP), developed analyses to detect potential manipulative behavior in the methodology used to offer their units into the wholesale market. These analyses were used to assess the exposure to regulatory liability and present arguments in front of the FERC.
- **Development of Screens to Detect Manipulation in Electricity Markets.** For several generation owners or power trading firms, designed screens to assist with the detection of a wide variety of behavior relevant to electric power market, including the inappropriate withholding of generation to benefit related positions, the uneconomic or fraudulent offer of generation to garner out-of-market payments, and the use of uneconomic physical or virtual price-making trades to impact the value of price-taking positions. Also evaluated specific types of "gaming" behavior and other types of trades (such as circular schedules, "sham" schedules or "wash-like" transactions) that could be viewed as manipulative.
- **Wholesale Electricity Market Manipulation.** For a generation owner in PJM, supported the construction of analyses to detect uneconomic behavior in the methodology used to offer their units into the wholesale market, as well as estimated any potential price suppression and harm caused to other generators. These analyses were used to assess the exposure to regulatory liability and to calculate possible damages.
- **Uneconomic Bidding.** For a merchant power provider, helped draft testimony filed with a regulatory body to provide clarity in its attempt to establish the proper definition of uneconomic bidding in the wholesale electricity market. Specific focus was paid to the bidding behavior of coal-fired power plants in day-ahead markets.
- **Electric Utility Rate Disputes.** As part of an electric utility rate case, aided in the development of testimony analyzing the financial wellbeing of a large industry customer. The testimony centered on determining the validity of the industrial customer's claimed need for rate relief.

- **Prevention of Manipulation in Capacity Markets.** Assisted in writing testimony filed in a tariff revision proceeding in front of the FERC. Provided guidance for an RTO in crafting tariff provisions to prevent and properly mitigate manipulative bidding behavior in its capacity market.
- **Prevention of Manipulation in Capacity Markets.** Assisted in writing testimony filed in front of the FERC. Provided guidance on developing market rules and procedures to prevent the manipulation of capacity auctions by imported resources.

Electric Power Strategic Planning

- **Development of a Regulatory Action Plan.** For an investor-owned utility and renewable developer, led a strategic planning initiative to engage policy staff across the organization to establish key policy areas for the organization. Specific policy objectives were created to focus policy advocacy, identify action items for the next 18 months of advocacy, and identifying a longer-term strategic plan for engaging commissions, market operators, and policymakers on the organizations key policy areas beyond the 18-month time frame. Developed a strategic action plan document establishing the regulatory action items for the organization.
- **Development of Strategic Action Plan.** For a cooperative in ERCOT, led a strategic planning initiative to engage with the board of directors to establish their vision for the organization, including core values for the organization to pursue as well as specific and actionable strategic priorities for senior management to implement. Created a framework to ensure the strategic priorities remained up to date and relevant for the cooperative and its members and to ensure that the board remained continually engaged on strategic issues. Led a strategic planning workshop for the cooperative's board of directors and utilized the output of workshops to create a strategic action plan document memorializing the core values, strategic priorities, and engagement framework.
- **Review and Development of Strategic Plan.** For a public power authority in SPP, led a strategic planning initiative to review existing strategic planning documents, guide the organization in creating an updated strategic plan, and helped create a framework for assessing evolving industry trends going forward. Led a strategic planning workshop for the C-suite and all senior management in the organization and used output of workshop to develop strategic initiatives and milestones for the utility.
- **Strategy Planning for Energy Transformation.** For a public power authority in the Southwest Power Pool (SPP), led a strategic planning initiative to address myriad issues

confronting the utility in the near future. The initiative covered de-carbonization, evolving customer preferences, human resource issues, reliability, data and IT challenges, and customer costs. Conducted strategic planning sessions with the executive team at the utility, which lead to the development of a strategic plan and de-carbonization proposal.

- **Integration of Emerging Technologies and Services.** For two distribution cooperatives, conducted a long-term strategic planning effort with executives and managers. Presented materials on technology trends, rate structure challenges and solutions, and challenges with regional transmission cost allocations and facilitated the development of long-term industry scenarios and strategic responses for a comprehensive corporate strategy.

TESTIMONY AND REGULATORY FILINGS

- Before the Federal Energy Regulatory Commission, Docket No. ER24-232-000, *Testimony of John Tsoukalis,* on behalf of New York Transco LLC, *re:* New York Transco LLC Proposed Rate Recovery Mechanism for Propel NY Energy Project, October 27, 2023.
- Before the United States District Court for the Western District of Missouri, Associated Electric Cooperative, Inc. vs. Southwest Power Pool, Inc., Case No. 6:22-cv-03030-BCW, *Expert Report of John H. Tsoukalis*, September 2, 2022.
- Before the Alberta Utilities Commission, Proceeding No. 26911, *Written Evidence of Johannes P. Pfeifenberger and John Tsoukalis*, on behalf of Capital Power Corporation, *re:* AESO Bulk and Regional Rate Design and Modernized DOS Rate Design Application, March 28, 2022.
- "Technical Review Committee's Review of Duke Energy's Solar Integration Service Charge (SISC)," coauthored with J. Pfeifenberger and S. Ross, filed with the North Carolina Utilities Commission, Docket No. E-100 Sub 175, November 1, 2021.
- Before the Federal Energy Regulatory Commission, Docket No. ER22-233-000, *Testimony of John Tsoukalis,* on behalf of Portland General Electric, *re:* Portland General Electric Company's Transmission Rate Filing and Limited Revisions to Open Access Transmission Tariff, October 28, 2021.
- "Transmission Planning for the 21st Century: Proven Practices that Increase Value and Reduce Costs," coauthored with J. Pfeifenberger, K. Spokas, J. Hagerty, R. Gramlich, M. Goggin, J. Caspary, and J. Schneider, filed with the Federal Energy Regulatory Commission, Docket No. RM21-17-000, *Comments of the American Council on Renewable Energy*, Exhibit 6, October 12, 2021.
- Before the Federal Energy Regulatory Commission, Docket No. ER18-99-005, *Rebuttal Testimony of John Tsoukalis,* on behalf of GridLiance High Plains LLC, *re:* Benefits of Transmission Assets and Regional Cost Recovery under the SPP OATT, July 15, 2021.
- Before the Federal Energy Regulatory Commission, Docket No. ER18-99-005, *Direct Testimony of John Tsoukalis,* on behalf of GridLiance High Plains LLC, *re:* Benefits of Transmission Assets and Regional Cost Recovery under the SPP OATT, April 20, 2021.
- "Response to Third Party Submissions Regarding Alleged UTS of 2019," coauthored with P. Bagci and J. Reitzes, 10 November 2019, Undesirable Trading Situation Preliminary Decision Cross Submission filed with The New Zealand Electricity Authority, September, 16, 2020.

- "New Zealand Electricity Authority's Preliminary Decision on UTS," coauthored with P. Bagci and J. Reitzes, 10 November 2019, Undesirable Trading Situation Preliminary Decision Submission filed with The New Zealand Electricity Authority, August, 18, 2020.
- Before the Federal Energy Regulatory Commission, Dockets No. ER18-2358-001 and ER19-1357-000, *Rebuttal Testimony of John Tsoukalis,* on behalf of GridLiance High Plains LLC, *re:* Regional Cost Recovery under the SPP OATT for GridLiance transmission assets, March 27, 2020.
- "GridLiance System Analysis: Transmission Facility Classification," prepared for GridLiance High Plains LLC, coauthored with J. Chang, March 27, 2020. Filed with the Federal Energy Regulatory Commission, Dockets No. ER18-2358-001 and ER19-1357-000.
- Before the Federal Energy Regulatory Commission, Docket No. ER20-644-000, *Affidavit of Johannes P. Pfeifenberger and John Tsoukalis,* on behalf of Golden Spread Electric Cooperative, *re:* Comments on SPP Compliance Filing Revising Fast Start Pricing Practices, January 21, 2020.
- "Joint Dispatch Agreement Energy Imbalance Market Participation Benefits Study," prepared for Black Hills Corporation, Colorado Springs Utilities, Platte River Power Authority, Public Service Company of Colorado, coauthored with J. Chang, J. Pfeifenberger, S. Leamon, and C. Peacock, January 14, 2020. Filed with the Colorado Public Utilities Commission on January 28, 2020, Processing No. 19M-0495E, filing No. G 762524.

ARTICLES, PUBLICATIONS, AND PRESENTATIONS

- "NV Energy Day-Ahead Market Benefit Studies: Comparative Benefits for NV Energy of Joining EDAM versus Markets+," presented to the Public Utilities Commission of Nevada, April 3, 2024.
- "Section 45V Clean Hydrogen Production Tax Credits: Comments on Proposed Treasury Guidelines," prepared for the Los Angeles Department of Water and Power, coauthored with J. Figueroa, R. Sreenath, and E. Curtis, February 26, 2024.
- "Wholesale Markets and GHG in the WECC: Past, Present, and Future," Law International Seminars Electric Power in the West, January 26, 2024.
- "Extended Day-Ahead Market Participation Benefits Study," prepared for Balancing Area of Northern California, Idaho Power Company, Los Angeles Department of Water and Power, PacifiCorp, and Sacramento Municipal Utility District, coauthored with J. Pfeifenberger, K. Van Horn, and E. Bennet, December 2023.
- "MISO South Tranche 3 Transmission Planning and Cost Allocation," Entergy Regional States Committee Meeting, co-presented with M. Hagerty, September 8, 2023.
- "Extended Day-Ahead Market Benefits Study," presented to the EDAM Forum, August 30, 2023.
- "Greenhouse Gas and Clean Energy Accounting Methodology Catalog," prepared for the WEST Associates, coauthored with K. Spees, J. Grove, and L. Lam, June 2023.
- "Brattle EDAM Simulations: PacifiCorp Results," presented to the Wyoming Public Service Commission, Oregon Public Service Commission, Idaho Public Utilities Commission, and the Public Service Commission of Utah, and the Washington Utilities and Transportation Commission, coauthored with J. Pfeifenberger and E. Bennett, May-July, 2023.
- "Assessment of Potential Market Reforms for South Carolina's Electricity Sector," prepared for the South Carolina General Assembly, coauthored with K. Spees, J. Pfeifenberger, A. Levitt, A. Thompson, O. Kuzura, E. Bennett, S. Pon, M. Diehl, E. Curtis, S. Tang, and R. Nelson, April 27, 2023.
- "A Roadmap to Improved Interregional Transmission Planning," prepared for the Natural Resources Defense Council, coauthored with J. Pfeifenberger, K. Spokas, and J. Hagerty, November 30, 2021.

- "The Benefit and Cost of Preserving the Option to Create a Meshed Offshore Grid for New York," prepared for the New York State Energy Research and Development Authority, coauthored with J. Pfeifenberger and S. Newell, November 9, 2021.
- "Transmission Investment Needs and Challenges," presented for JP Morgan Renewables and Grid Transformation Series, coauthored with J. Pfeifenberger, June 1, 2021.
- "2020 CAISO Blackouts and Beyond: The Future of California Resource Planning," presented for LSI Electric Power in the West Conference, coauthored with F. Graves and S. Leamon, January 29, 2021.
- "Western Energy Imbalance Service and SPP Western RTO Participation Benefits," prepared for the Southwest Power Pool, coauthored with J. Pfeifenberger, M. Celebi, S. Leamon, C. Peacock, and S. Ganjam, December 2, 2020.
- "Understanding Wholesale Power Market Designs and Their Benefits," Infocast Southeast Renewable Energy Conference, November 19, 2020.
- "Building Support for Grid Transformation," EUCI Workshop, August 18, 2020.
- "Recommendations on Resource-Specific Offer Caps March 2021 Capacity Auction for Commitment Period May 2022 to April 2023," prepared for the Ontario Independent Electricity System Operator, coauthored with K. Spees, J. Pfeifenberger, and C. Haley, March 4, 2020.
- "Analysis of TRCA Surplus Allocation Methodology," prepared for the Ontario Independent Electricity System Operator, coauthored with S. Ledgerwood, E. Shorin, and J. Higham, October 4, 2019.
- "Renewable Energy Development and IT Sector Load Growth," Law Seminars International Electric Power in the Southwest Conference, July 15, 2019.
- "Potential Benefits of a Regional Wholesale Power Market to North Carolina's Electricity Customers," commissioned by the North Carolina Clean Energy Business Alliance, Carolina Utility Customers Association, and Conservatives for Clean Energy – North Carolina, coauthored with J. Pfeifenberger and J. Chang, April, 2019.
- "SPP's Proposed Ramp Product: Initial Recommendations for Maximizing the Benefits of a Ramping Product," presented to SPP's Holistic Integrated Tariff Team, coauthored with J. Pfeifenberger, J. Chang, and K. Spees, September 11, 2018, and October 23, 2018.
- "Initial Comments on SPP's Draft Ramp Product Report," prepared for Golden Spread Electric Cooperative, Inc. (with J. Pfeifenberger, J. Chang, and K. Spees), August 30, 2018.

- "Framework-Based Approach to Building an Effective Trade Surveillance System and Compliance Program," EUCI Financial Transmission and Auction Revenue Rights Conference, January 31, 2018.
- "Trade Surveillance Should Not Deter Traders," coauthored with Shaun Ledgerwood, December 27, 2017, published by *Risk.net.*
- "Building an Effective Trade Surveillance System: A Framework-Based Approach using Guidance from Two Recent FERC White Papers," coauthored with S. Ledgerwood, March 20, 2017, published by *The Brattle Group.*
- "Production Cost Savings Offered by Regional Transmission and a Regional Market in the Mountain West Transmission Group Footprint," prepared for Basin Electric Power Cooperative, Black Hills Corporation, Colorado Springs Utilities, Platte River Power Authority, Public Service Company of Colorado, Tri-State Generation and Transmission Cooperative, and Western Area Power Administration (with J. Chang and J. Pfeifenberger), December 1, 2016.
- "FERC's Market Manipulation Rule: Impact on FTRs and the Virtual Market," Energy Bar Association Midwest Chapter Annual Meeting, March 8, 2016.
- "The Critical Role of Transmission in Clean Power Plan Compliance," Kinetic Conference for Competitive Bidding for Transmission Expansion, November 17, 2015.
- "Investment Trends and Fundamentals in U.S. Transmission and Electricity Infrastructure," JP Morgan Investor Conference, July 17, 2015.
- "Market Manipulation Push is Widening the Compliance Gap," coauthored with S. Ledgerwood, January 23 2015, *published on Risk.net*
- "Dynamics and Opportunities in Transmission Development," TransForum East (Washington DC), December 2, 2014.
- "The Power of Dynamic Pricing," coauthored with Ahmad Faruqui and Ryan Hledik, *The Electricity Journal*, April 2009, pp. 42-56.

Case No. PAC-E-24-04
Exhibit No. 30
Witness: John Tsoukalis

BEFORE THE IDAHO PUBLIC UTILITIES COMMISSION

ROCKY MOUNTAIN POWER

Exhibit Accompanying Direct Testimony of John Tsoukalis

Summary of Net Power Cost Adjustment Mechanisms in Regulated States

May 2024

Survey of Net Power Cost Adjustment Mechanisms in Regulated States

State	Deadband	Risk Sharing	Regional Market	Description of Adjustment Clause from S&P Global Capital IQ Commission Report
Alabama				Alabama Power, Spire Alabama and Spire Gulf are regulated under Rate Stabilization and Equalization frameworks that adjust base rates periodically. The tariffs of the major energy utilities include adjustment provisions to allow for recovery of changes in income taxes and certain general and local taxes. An Energy Cost Recovery, or ECR, mechanism is also in place for Alabama Power. The ECR mechanism is established on the basis of estimates of electric sales, fuel-related costs, and purchased power costs, and reflects accumulated over- or underrecovered amounts.
Alaska				Electric fuel and gas commodity costs are recovered through mechanisms that are separate from base distribution rates. Alaska Electric Light and Power Co. utilizes a power cost adjustment that is updated quarterly. ENSTAR Natural Gas Co.'s gas cost adjustment is updated annually; both are subject to true-up.
Arizona		Yes. **APS'** PSA is subject to a $0.004/kWh annual cap on rate increases or decreases, unless the base cost of fuel and purchased power is reset.		Arizona Public Service Co., or APS, utilizes a Power Supply Adjustor, or PSA, a mechanism that permits the deferral and recovery of fuel and purchased power costs, certain production-related variable costs, and certain energy storage costs outside of a rate case. The PSA is subject to a $0.004/kWh annual cap on rate increases or decreases, unless the base cost of fuel and purchased power is reset. The PSA incorporates a forward-looking estimate of fuel and purchased power costs to set a rate that is subsequently reconciled with actual costs. The PSA consists of three components: the "forward component" that recovers or refunds differences between expected fuel and purchased power costs and those reflected in base rates; the "historical component," which tracks the differences between actual costs and those recovered through the combination of base rates and the forward component; and the "transition component," which provides for the recovery or refund of deferred balances stemming from the operation of the old PSA. The PSA also reflects margins from the sale of emissions allowances. Tucson Electric Power Co., or TEP, utilizes a purchased power and fuel adjustment clause, or PPFAC. The PPFAC includes a forward-looking component. A PPFAC is also in place for UNS Electric Inc., or UNS-E.
Arkansas			MISO, SPP	State statutes permit the electric utilities to request PSC approval of mechanisms that allow the recovery of costs related to fuel and purchased power, energy efficiency, purchased gas and certain other items. Energy cost recovery, or ECR, riders — Electric utilities recover fuel and purchased power costs through an ECR rider. The ECR rider is calculated annually, reflecting the actual cost in the previous calendar year, with an adjustment for projected changes. ECR rate changes are implemented automatically; however, a utility's ECR rider calculation is subject to a 15-day review period. The staff is permitted to audit any utility's ECR rider and can recommend adjustments to the ECR rate filed by the company. Oklahoma Gas & Electric Co.'s, or OG&E's, ECR rider provides for the flow-through to ratepayers of 100% of the Arkansas jurisdictional proceeds from the sale of excess SO2 emissions allowances as well as a share of the value of "green credits" resulting from the monetized environmental benefits of generation at the company's Centennial Wind Farm equal to the portion of the project dedicated to serving the Arkansas jurisdiction.
California			CAISO	The state's major electric utilities utilize a balancing account, the energy resource recovery account, or ERRA, that is designed to track and allow recovery of the difference between electric procurement costs included in rates and actual costs incurred under each utility's procurement plan. The PUC must review the revenues and costs associated with each utility's electricity procurement plan at least annually and adjust retail electricity rates or order refunds as appropriate, typically once a year. In addition, rate changes can be implemented based on the ERRA trigger mechanism, which is effective when aggregate over-collections or undercollections exceed 5% of the utility's prior-year electric generation revenues, excluding amounts collected for the Department of Water Resources. The PUC would make the final determination of an ERRA trigger mechanism rate change. Additional Source: Note that some utilities in California, like PacifiCorp, have an Energy Cost Adjustment Clause (ECAC) instead of an ERRA. This functions in a similar manner and allows for full pass through of net power costs to customers. PacifiCorp's Application for approval of its 2024 ECAC, accessed at https://www.pacificpower.net/content/dam/pcorp/documents/en/pacificpower/rates-regulation/california/filings/docket-a-23-09-008/Application_of_PacifiCorp.pdf.
Colorado				Public Service Co. of Colorado's, or PSCO's, fuel and purchased energy costs are recovered through an electric commodity adjustment, or ECA, rider that compares actual fuel and purchased power expenses to a formula based benchmark. The ECA contains certain earnings-sharing provisions related to energy trading activities and certain incentives related to PSCO's Rush Creek wind farm flow through the mechanism. PSCO utilizes a purchased capacity cost adjustment, or PCCA, clause that allows for recovery of the costs of purchased power not included in base rates or other recovery mechanisms. Pursuant to a settlement adopted by the PUC in March 2020, PSCO is to reflect costs associated with the gas-fired, 301-MW Manchief facility through its ECA and PCCA after it acquires the plant. Manchief currently serves the company through a purchased power agreement, or PPA, that extends to 2022, and PSCO is to acquire the plant at the expiration of the current PPA contract. Black Hills Colorado Electric, LLC, or BHCE, is subject to an energy cost adjustment mechanism under which all fuel and purchased energy cost differences from the company's base energy cost rate are fully recovered from, or credited to, customers. The impacts of certain incentive mechanisms also flow through the mechanism.
Florida				The fuel cost recovery clause, or FCRC, and the capacity cost recovery clause, or CCRC, provide for recovery of prudently incurred fuel and purchased power costs, respectively. Annual fuel factors are established based upon 12-month projections of fuel costs and energy purchases and sales. Hearings are held each November, during which the PSC sets fuel factors for the next calendar year. Subsequent to the November hearings, utilities may seek, or the PSC may require a midterm modification to the factors if updated projected costs for the year vary from updated projected revenues by plus or minus 10%. Interest is accrued on both over- and under-recovered balances. Included in the FCRC is a generating performance incentive factor that provides a financial reward or penalty when a company's base load generating units' availability and heat rate vary from targets approved by the PSC. The reward or penalty is limited to a 25-basis point ROE spread. The PSC generally requires market-based pricing of coal purchased from an affiliate. The FCRC also reflects gains from non-firm energy sales. A three-year moving average based on eligible sales is determined, and 100% of the sales up to this benchmark are credited to ratepayers. For sales above the benchmark, 80% of the gains accrue to ratepayers, with 20% retained by Duke Energy Florida LLC, or DEF; Tampa Electric Co., or TEC; and Gulf Power Co., or GP.
Georgia				A non-automatic fuel adjustment mechanism, known as the fuel cost recovery clause, is in place for Georgia Power, or GP. Hearings are required before increases or decreases are implemented. Electric fuel rates are based on estimated sales and fuel costs, and any balance of previously unrecovered/over-recovered fuel costs is considered in setting new rates. The energy portion of purchased power transactions is reflected in the mechanism; the capacity component is recovered through base rates. The cost of GP's natural gas and oil procurement hedging program, including any net gains or losses, are also recovered through the fuel cost recovery clause.
Hawaii		Yes. **Hawaiian Electric Companies** recover 98% of fuel cost fluctuations from customers and incur 2% (with utility exposure capped at $2.5 million)		Fuel adjustment clauses are in place for electric utilities. The clauses are adjusted monthly for changes in fuel costs and the fuel-cost component of purchased energy, and for variations from the forecasted generation mix. Hawaiian Electric Company's, or HECO's, purchased power adjustment clause, or PPAC, is designed to recover purchased power capacity costs and the O&M expense component of purchased power energy costs. Similar mechanisms are in place for Hawaii Electric Light Company, or HELCO, and Maui Electric Company, or MECO. Rates under the PPAC mechanisms are adjusted monthly. Additional sources: PUC Final Decision and Order No. 35545, p. 3, accessed at https://puc.hawaii.gov/wp-content/uploads/2018/06/DO-No.-35545.pdf.

Survey of Net Power Cost Adjustment Mechanisms in Regulated States

State	Deadband	Risk Sharing	Regional Market	Description of Adjustment Clause from S&P Global Capital IQ Commission Report
Idaho		Yes. **Avista's** PCA enables the company to defer 90% of net power cost deviations, similar to **PacifiCorp. Idaho Power**'s PCA includes a 95% sharing mechanism		Electric power cost adjustment, or PCA, mechanisms are utilized by Avista Corp., Idaho Power Co., and PacifiCorp. Semi-automatic purchased gas adjustments are utilized by Avista and Intermountain Gas Co. Electric and gas utilities may seek PUC approval to issue energy cost recovery (securitization) bonds to moderate the impact of power cost increases on customers (see the Securitization section). Avista's PCA enables the company to defer, in a balancing account, 90% of the difference between actual net power costs and the amount included in retail rates. Idaho Power has a similar mechanism in place with a sharing provision under which annual rate adjustments reflect 95% of the cost variations associated with water supply for hydro-electric production, fuel costs, wholesale energy prices, and retail load changes. An energy cost adjustment mechanism is in place for PacifiCorp that allows for the recovery of 90% of the difference between actual power costs and those included in rates.
Indiana			MISO, PJM	Electric utilities may adjust rates for changes in fuel and purchased power — energy component only — costs generally every three months, following hearings, through the FAC. The FAC is based on estimated costs of fuel and purchased power for a future three-month period, with an additional factor to account for over- or under recoveries caused by variances between estimated and actual costs in the previous three-month period. No carrying charges accrue on over- or under-recoveries. The adjustment factor may be modified more frequently than every three months under emergency circumstances. By law, the URC may not approve an FAC rate adjustment if it will result in the utility earning a net operating income, or NOI, in excess of that authorized.
Iowa			MISO, SPP	Energy adjustment clauses, or EACs, are modified monthly based on forecast energy costs and fuel and purchased power for two months. The capacity/demand portions of purchased power are recovered through base rates. Under- and over-recoveries are deferred and respectively charged and credited to customers in the succeeding months. Interstate Power and Light Co., or IP&L, uses an EAC that provides for recovery of fuel and purchased power costs as well as revenues and costs associated with sales or purchases of emission allowances. MidAmerican Energy Co. uses an EAC that excludes chemical-related costs.
Kansas			SPP	The major electric utilities in Kansas, Empire District Electric Co., Evergy Kansas Central Inc., Evergy Kansas South Inc. and Evergy Metro Inc. utilize ECA mechanisms to recover variations in fuel and purchased power costs. The ECA is generally calculated monthly based on projected fuel and purchased power costs for that month, with any under- or over-recoveries reflected in the subsequent month. Penalties may be imposed if actual costs exceed projections for three consecutive months. Utilities using an ECA mechanism are required to annually discuss fuel planning and purchasing practices with the staff and fuel contracts are to be competitively bid whenever possible. Any contracts awarded after a competitive bidding process that has been endorsed by the staff are accorded a "presumption of reasonableness" by the KCC. Any contract longer than one month that is not competitively bid must receive KCC approval before the effective date. Through their ECA mechanisms, all of the utilities pass along 100% of off-system sales margins that vary from a base level and the net cost of emission allowances to ratepayers.
Kentucky			MISO, PJM	The PSC allows fuel and purchased power — energy only — costs to be recovered through automatic FACs. Adjustments are implemented monthly, based on actual costs for the second preceding month, producing a two-month lag. There is a provision for the true-up of any under- or over-recovery included in the clause. Incremental replacement power cost increases resulting from forced outages cannot be recovered through the FAC. Public hearings are held every six months to examine procurement and other practices related to fuel and purchased power cost recovery, and adjustments are made to correct for any costs that the PSC determines are unjustified. Additional proceedings are conducted every two years to evaluate the operation of the clause and to set the level of such charges to be included in base rates.
Louisiana			MISO	The state's electric utilities recover fuel and purchased power, energy only, costs through a fuel adjustment clause, or FAC. The demand component of purchased power costs related to "economy" purchases, i.e., entered into by a company when the price of the purchased power is below the cost of the company's own generation, may also be recovered through the FAC. Monthly filings are required for implementation of changes in the adjustment factor. The utilities accrue over- or under-recoveries, with the bulk of the accumulated balances refunded/recovered over subsequent 12-month periods. The PSC may audit a utility's purchased power and fuel acquisition practices, and if the commission determines that the charges passed through the FAC were unreasonable, refunds may be required.
Minnesota			MISO	Automatic fuel and purchased gas adjustment, or PGA, clauses are utilized. For most electric utilities, the electric fuel clause is adjusted monthly with a two-month lag. For Northern States Power Co.-Minnesota, or NSP-M, the PUC permits a forecast fuel clause that projects monthly costs and provides for a true-up to actual costs. Electric utilities are required to submit to the PUC an annual report regarding the operation of the electric fuel clause. In 2017, the PUC amended the process through which utilities seek fuel cost recovery. Under the new process, the individual monthly fuel cost forecasts are be set on an annual basis, and monthly variations will be tracked and netted over a 12-month period. The implementation date for this order was extended until Jan. 1, 2020. The forecast year is to be a calendar year. Each utility is required to file its annual fuel forecast petition in a separate docket. In December 2017, the PUC issued its order changing the process through which utilities seek fuel cost recovery. Under the new process the individual monthly fuel cost forecasts will be set on an annual basis, and monthly variations will be tracked and netted over a 12-month period. The implementation date for this order was extended until Jan. 1, 2020. The PGA provides for monthly rate revisions to reflect the total current unit cost of purchased gas. PGA factors by major customer class are calculated for the current month based on estimated purchased gas costs for that month. By September of each year, utilities are required to submit to the PUC an annual report of the fuel and PGA factors used to bill each customer class for the previous year beginning July 1 and ending June 30.
Mississippi			MISO	By law, the PSC may approve expedited recovery mechanisms for fuel, purchased power and commodity costs. The PSC must conduct an annual audit of all fuel purchases and interchange contracts and submit an annual report to the Legislature. Automatic electric fuel adjustment clauses, are in place for Mississippi Power, or MP, and Entergy Mississippi, or EM, with the energy component of purchased power recovered through the fuel clause and the capacity component recovered in base rates. Both MP and EM use levelized fuel adjustment clauses based upon projected fuel use and costs, with a provision for the reconciliation of over and under recoveries. MP's fuel adjustment is set for a 12 month period, while EM's is adjusted quarterly. EM and MP also have separate energy cost management clauses to recover fuel hedging gains, losses, and expenses. EM and MP may recover emissions allowance expenses through their adjustment clauses.
Missouri		Yes. **Empire District Electric Co, Kansas City Power and Light,** and **Union Electric** can all recover 95% of fuel and purchased power costs, net emissions allowance costs and OSS revenues that vary from levels included in base rates.	MISO, SPP	Empire District Electric Co., Union Electric Co. (UE), Evergy Metro Inc. and Evergy Missouri West Inc. utilize FACs that provide for the companies to recover from/flow to ratepayers 95% of variations in "prudently incurred" fuel and purchased power costs, net emissions allowance costs and OSS revenues. In rate case decisions issued in recent years, these companies were required to exclude from their FACs a portion of the transmission costs they incur related to their participation in regional transmission organization markets. The commission determined that the transmission costs these companies can include in their FACs are costs incurred to transmit power that is sourced from generation plants not owned by the companies to serve their native load, and costs incurred to transmit excess power the companies sell to third parties in locations outside of these markets. The PSC prohibited the companies from recovering through the FACs costs related to the power they produce, sells into the markets and subsequently repurchase for their native load.

Survey of Net Power Cost Adjustment Mechanisms in Regulated States

State	Deadband	Risk Sharing	Regional Market	Description of Adjustment Clause from S&P Global Capital IQ Commission Report
Montana		Yes. **NorthWestern Energy** and **MDU Resources Group** both have power cost adjustment mechanisms that include a 90% rate payers/10% shareholders cost share	MISO, SPP	On July 14, 2017, NorthWestern filed its Power Costs and Credits Adjustment Mechanism, or PCCAM, proposal with the commission. The proposed PCCAM provides for annual adjustments based on 12 months of actual data, and provides of a 90%/10% allocation between rate payers and shareholders of the related costs. The PCCAM would temporarily apply to Demand Side Management program costs and certain administrative and general costs until future treatment is determined as part of NorthWestern's next general electric rate case. The commission is expected to hold a hearing on the matter on May 31, 2018. MDU Resources Group utilizes a monthly-adjusted fuel and purchased power cost adjustment mechanism that contains certain incentive provisions, including a 90%/10% sharing of the costs reflected in the mechanism. Additional source: Northwestern Energy Power Costs and Credits Adjustment Mechanism Tariff, accessed at https://www.northwesternenergy.com/docs/default-source/default-document-library/billing-and-payment/rates-and-tariffs/montana/rates/epcc-1.pdf
Nevada				Electric utilities are subject to a deferred energy cost recognition procedure, under which Commission approval is required prior to implementation of changes in the recovery of fuel and purchased power costs. In accordance with this procedure, Nevada Power Company, or NPC, and Sierra Pacific Power Company, or SPP, file quarterly deferred energy adjustment applications, or DEAAs, proposing to recover or refund the deferred balances, representing the difference between actual fuel and purchased power costs incurred and the amounts currently reflected in rates. Electric utilities must reset, on a quarterly basis, the rate for ongoing fuel and purchased power costs, referred to as the base tariff energy rate, or BTER. The quarterly reset is designed to reflect power costs on a more current basis, thereby eliminating large deferred energy balances. These quarterly BTER adjustments are reviewed annually by the PUC as part of the companies' DEAA filings. Costs eligible for recovery include all prudent expenses incurred to purchase fuel, capacity, and energy, as well as the carrying charges on deferred balances. The burden of proof regarding prudence rests with the utility.
New Mexico			SPP	Commission rules provide for automatic fuel adjustment clauses; the fuel and purchased power cost adjustment clause, or FPPCAC, for an electric utility is calculated monthly, but a variance from monthly reporting may be sought. The FPPAC includes a balancing account in which there is approximately a two-month collection lag. A utility is required to reapply for continuation of an FPPCAC every four years, at which time a comprehensive review of the clause is undertaken. In 2008, the PRC authorized Public Service Co. of New Mexico, or PSNM, to establish an emergency FPPCAC. The clause contained several conditions, including that the recoverable costs were subject to a prudence review. PSNM's FPPCAC had been eliminated in 1994, following a stipulation. In 2009, the PRC adopted a rate case settlement that included the reinstatement of the company's FPPCAC on a permanent basis. The fuel factor is adjusted annually. Additionally, the approved settlement contained an SO2 rider through which customers are credited with their share of revenues from allowance sales. El Paso Electric Co., or EPE, may seek approval to adjust its FPPCAC if the company experiences an over- or under-recovery balance of at least $2 million of fuel and purchase power expenses as of Dec. 31 and June 30 of each year. Southwestern Public Service Co., or SWPS, uses an FPPCAC under which it may petition for a change in the fuel factor if the over/under-recovery balance reaches $5 million.
North Carolina			PJM	Prudent electric fuel and fuel-related costs are recoverable through a fuel adjustment clause, or FAC. Each utility has an annual hearing to review fuel costs, with a test period determined by the NCUC for each company. The proceedings provide for a true up of any over or undercollections from the previous year, with interest included only for overcollections. The costs of certain reagents, e.g., limestone, used in reducing or treating emissions, as well as certain nonfuel purchased power costs for economic purchases, may be recovered through the FAC. The law limits the annual increase in recoverable costs related to certain purchased power contracts to 2% of a utility's total retail revenues.
North Dakota			MISO, SPP	Mechanisms that provide for automatic recognition of changes in fuel and the energy portion of purchased power costs are in place for Montana-Dakota Utilities (MDU), Northern States Power (NSP) and Otter Tail Power. Fuel and purchased power cost adjustments are implemented monthly and are based on a rolling four-month history. There is generally a two-month lag for recovery. MDU also recovers capacity costs associated with purchased power through its fuel and purchased power adjustment clause.
Oklahoma			SPP	Fully automatic electric FACs are prohibited in Oklahoma. However, semi-automatic FACs are in place. Utilities may propose a change in the current FAC billing factor according to each company’s Commission-approved FAC tariff. Once the utility files for a change in its FAC rate, the staff has five days within which to respond. If the staff files objections to the change, a formal investigation is initiated; if the staff files no objections, the proposed rates become effective. The historic costs and revenues included in the FAC are reviewed by the OCC after each calendar year for accuracy and prudence. Oklahoma Gas & Electric Co.'s, or OG&E's, FAC is typically adjusted semi-annually but can be adjusted quarterly if costs have changed and are expected to remain at their current levels for the foreseeable future or if the monthly over or undercollected FAC amounts for a given period are greater than 5% of the company's projected annual Oklahoma-jurisdictional fuel costs. Purchased power and certain cogeneration and capacity payment differentials are reflected in the FAC. OG&E also recovers a portion of the transportation costs associated with gas deliveries to its generating facilities through the FAC. Public Service Co. of Oklahoma's, or PSO's, FAC is adjusted annually, subject to a cap on under and overrecoveries. However, an immediate adjustment may be implemented if the under or overrecovered balance exceeds $50 million. Otherwise, amounts that differ from the levels reflected in base rates are deferred in a balancing account, and the deferrals are recovered over the subsequent 12 months. The FAC also allows for current recovery of line losses above or below the amount recognized in PSO's base rates. Such under or overrecoveries are recovered from, or refunded to, customers during subsequent months. Ratepayers' 90% share of off system sales margins flow through PSO's FAC.
Oregon	Yes, **PGE** and **PacifiCorp** have a -$15 to $30 million deadband, while **Idaho Power's** costs/savings are reduced by a deadband of 250/125 ROE basis points	Yes. PCAMs for **PGE, PacifiCorp,** and **Idaho Power** all recover 90% of cost deviations outside of a deadband		Portland General Electric, or PGE, PacifiCorp, and Idaho Power, or IP are permitted to annually adjust rates to reflect forecasted power costs. PGE's and IP's mechanisms include a component under which a portion of the difference between actual and forecasted power costs is deferred for future recovery or refund. PGE's current power cost recovery framework includes both an annual update, under which rates change each January 1 to reflect updated net variable power costs, or NVPC, and a power cost adjustment mechanism, or PCAM, that is designed to capture a portion of the difference between the NVPC forecast established through the annual update, i.e., baseline NVPC, and the actual NVPC incurred by PGE for that year. The PCAM is subject to a deadband of $15 million below to $30 million above the ultimately established NVPC, a sharing ratio, and an earnings test. PGE absorbs 100% of the costs/benefits within a PUC-determined deadband, and amounts above or below the deadband are allocated 90% to customers and 10% to PGE shareholders. A surcharge or a refund would occur only if PGE's actual ROE is more than 100 basis points below or above PGE's last authorized ROE. PacifiCorp and IP have similar mechanisms.
South Carolina				Nonautomatic electric fuel and purchased gas adjustment clauses are in place for the state’s utilities. Each electric utility is required to furnish the PSC an estimate of its fuel costs, including the cost of purchased power, for a prospective 12-month period. The PSC then determines the fuel-related costs to be included in base rates for that period, including adjustments for over or under recovery from the preceding 12-month period. Electric companies are required to account on a monthly basis for the difference between fuel costs recovered through base rates and actual fuel costs by booking the difference to unbilled revenue with a corresponding deferred debit or credit. Emissions allowance costs and the cost of certain materials used in reducing or treating emissions are reflected in the fuel clause.

Survey of Net Power Cost Adjustment Mechanisms in Regulated States

State	Deadband	Risk Sharing	Regional Market	Description of Adjustment Clause from S&P Global Capital IQ Commission Report
South Dakota			MISO, SPP	Automatic fuel, purchased power, and gas cost adjustment clauses are permitted. Through these clauses, the utilities recover actual fuel, purchased power — energy portion only — and purchased gas expenses incurred; carrying costs accrue on unrecovered balances. The fuel clauses of Northern States Power, Black Hills Power and NorthWestern Corp. contain certain incentive provisions.
Tennessee				Automatic purchased power and gas commodity recovery clauses are permitted. The state's gas utilities are allowed to reflect a portion of uncollectible expenses in these clauses. Kingsport Power, or KP, has a fuel and purchased power adjustment rider that reflects any changes in the wholesale costs of the company's power supplier, affiliate Appalachian Power, or APCO, as well as transmission expenses. KP has no generating capacity of its own, and purchases 100% of its power requirements from APCO. Chattanooga Gas, or CG, has a purchased gas adjustment rider in place.
Utah				The PSC may allow electric and gas utilities to implement balancing accounts to recover purchased power and fuel costs. In 2011, PacifiCorp implemented a pilot energy balancing account, or EBA, that was to remain in place through 2016 and contained incentive provisions. However, legislation was enacted on March 29, 2016, that removed the incentive provision of the mechanism and extended the EBA through 2019. Also, PacifiCorp operates under a renewable energy credit mechanism that contains certain incentive provisions. PacifiCorp operates under an energy balancing account, or EBA, whereby the company recovers 100% of incremental variations in actual net power cost, or NPC, levels from a baseline level established in the company's most recent general rate case. Previously, variations in PacifiCorp's NPC were allocated 70% to ratepayers and 30% to shareholders. PacifiCorp allocates incremental revenues associated with the sale of renewable energy credits that exceed a certain baseline level on a 90%/10% basis to ratepayers and shareholders, respectively.
Vermont	Yes. **Green Mountain Power** has an assymetrical deadband of $150,000/$307,000.	Yes. **Green Mountain Power** can pass through to ratepayers 90% of the energy costs (or benefits) outside the deadband.	ISO-NE	Power cost adjustment, or PCA, and purchased gas adjustment, or PGA, mechanisms are permitted, provided that the mechanisms are part of an alternative regulation plan. Vermont Gas Systems, or VGS, has a PGA mechanism in place that allows for the recovery of all gas-cost variations on a quarterly basis. The Vermont Supreme Court has prohibited the use of PCA and PGA mechanisms, finding them to be inconsistent with the customer notice requirements under state law. However, these mechanisms are permitted when adopted as part of an alternative regulation plan. Additional source: Green Mountain Power Multi-Year Regulation Plan, October 1, 2022.
Virginia			PJM	Electric fuel adjustment clauses, or FACs provisions are permitted. The SCC's FAC procedure provides for electric rates to be reset annually based on projected usage and costs. The utilities maintain accounts for any over or underaccruals, and these balancing accounts are reconciled through the following year's fuel factor. Purchased power and capacity charges for "economy" purchases are included in the fuel factor calculation. Energy charges associated with reliability purchases may flow through the fuel factor, but capacity charges are recovered through base rates. Appalachian Power Co., or APCO, Virginia Electric and Power Co., or VEPCO, and Kentucky Utilities Co., all use an FAC.
Washington	Yes. **Avista, PSE**, and **PacifiCorp** employ deadbands of respectively ± $4 million, ±$17 million, and ±$4 million respectively	Yes. Under **Avista's** ERM, if costs are $4 million - $10 million lower than those included in base rates, 75% of the energy cost savings flow to customers. Costs between $4 million to $10 million higher are shared equally, while differences above $10 million are allocated 90% to customers and 10% to shareholders. **PSE** and **PacifiCorp** similarly pass costs to customers outside of a deadband based on a graduated scale		Avista Corporation's Energy Recovery Mechanism, or ERM, allows the company to adjust rates to reflect changes in power supply related costs, with 75% of any energy cost savings to flow to customers and 25% to the company when actual annual power costs are between $4 million and $10 million lower than those included in base rates. Equal sharing is to occur when actual power costs are between $4 million and $10 million greater than the amount included in base rates. Any differences in excess of $10 million are to be allocated 90% to customers and 10% to shareholders. The ERM contains an adjustment trigger under which a surcharge or rebate occurs when the deferred ERM balance reaches ±$30 million. Puget Sound Energy's, or PSE's, Power Cost Adjustment Mechanism, or PCAM, allows for variations in power costs to be apportioned, on a graduated scale, between the company and customers. Beginning in 2017, to the extent power costs are above/below the PCAM baseline amount, PSE is to absorb/retain the first $17 million above/below the baseline, and 10% of any amount that exceeds $40 million. For costs between $17 million and $40 million above the baseline, PSE is to absorb 50%. For costs between $17 million and $40 million below the baseline, PSE is to retain 35% of the benefits. A PCAM rate surcharge/credit is to be implemented when the deferred power cost balance reaches ±$20 million. Fixed production costs are no longer included in the PCAM. As part of the company's now pending rate case filed in January 2017, these costs will be rolled in to the decoupling mechanism. In May 2015, the WUTC adopted a PCAM for PacifiCorp, following a settlement. The PCAM is a first for the company in Washington. The PCAM includes a $4 million dead band for net power cost variances, relative to a benchmark. For net power cost variances between $4 million and $10 million, the PCAM reflects asymmetrical sharing bands in which positive variances are to be allocated 50% to customers and 50% to PacifiCorp, and negative variances are to be allocated 75% to customers and 25% to PacifiCorp. Positive or negative net power cost variances in excess of $10 million are to be allocated 90% to customers and 10% to PacifiCorp.
West Virginia			PJM	Electric fuel and/or purchased power costs may be recovered through an expanded net energy cost (ENEC) proceeding. In addition to fuel costs, the ENEC paradigm reflects the energy portion of purchased power costs, the net benefit associated with affiliated and other wholesale sales, the demand portion of purchased power transactions, transmission costs and credits and any regional transmission organization-related costs. ENEC factors are set annually based on projected data for the prospective 12 months. Over- or under-recoveries based on actual data for the prior 12 month period are deferred for reconciliation as part of the next ENEC proceeding, with no carrying charges on the deferred balance. ENEC proceedings are typically completed within four months of filing.
Wisconsin	Yes, recovery for the five largest IOUs is subject to a ±2% deadband		MISO	Under the PSC's electric fuel rules, which apply to the state's five largest investor-owned utilities — Northern States Power Co. - WI, Wisconsin Power and Light Co., Madison Gas and Electric Co., Wisconsin Electric Power Co. and Wisconsin Public Service Corp. — each utility forecasts the monthly and annual fuel and purchased power costs on a prospective basis. If a company's actual fuel and purchased power costs are outside a monthly or cumulative monthly variance range around the forecasts and if the utility can demonstrate that these costs will likely be outside the annual range, the PSC may conduct a hearing to establish new rates. Currently, the annual variance range is plus or minus 2%. An electric utility is required to defer any fuel costs that are outside of its annual, symmetrical variance range for subsequent recovery or refund. Any over- or under-recovery of the actual costs in a year is determined in the following year and is then reflected in future billings to electric retail customers. Under the electric fuel rules, utilities are required to defer the benefit of lower costs if its actual fuel costs fall outside the lower end of the range, and is required to defer costs, less any excess revenues, if its actual fuel costs exceed the upper end of the range. Excess revenues are defined as revenues in the year in question that provide utilities with a greater return on common equity than authorized by the PSC.

Survey of Net Power Cost Adjustment Mechanisms in Regulated States

State	Deadband	Risk Sharing	Regional Market	Description of Adjustment Clause from S&P Global Capital IQ Commission Report
Wyoming		Yes. **Cheyenne Light, Fuel & Power** can allocate steam production costs 85% to ratepayers and 15% to shareholders, and other eligible costs 95% to customers and 5% to shareholders. **PacifiCorp** similarly has cost-sharing in place, but allocates 80% to ratepayers and 20% to shareholders		Cheyenne Light, Fuel & Power (CLF&P) operates under a power cost adjustment mechanism through which the company's power costs are classified into two categories. Category 1 costs include steam production costs, while category 2 costs include purchased power and capacity costs, transmission expenses, and certain other costs, and reflect any margins realized from off-system sales. Deviations in Category 1 costs from a base level are allocated 85% to ratepayers and 15% to shareholders. Deviations in Category 2 costs are allocated 95% to customers and 5% to shareholders. PacifiCorp has been operating under an energy cost adjustment mechanism (ECAM) since 2010. Under the initial ECAM, incremental variations in net power costs (NPCs) that differ from the base level are allocated 70% to ratepayers and 30% to shareholders. The commission, in 2015, approved the continuation of the current ECAM with certain modifications that allow for the inclusion of reagent chemical costs and start-up fuel costs. In 2021, the PSC modified the ECAM sharing band so that 80% is allocated to ratepayers and the remaining 20% to shareholders. In its 2023 general rate case, PacifiCorp proposed eliminating the sharing band to allow for 100% return or recovery from customers for the ECAM's incurred revenues and costs. However, during public deliberations in November 2023, the commission rejected the utility's request and maintained the current 80%/20% sharing band between ratepayers and shareholders. In addition, Montana-Dakota Utilities (MDU) collects from/credits to ratepayers variations in fuel and purchased power costs that deviate from an established base level through a power supply cost adjustment mechanism.

Sources and Notes:
The following states were excluded from the sample because they restructured states with retail competition, making them poor comparisons to Oregon and PacifiCorp: Connecticut, Delaware, Illinois, Maine, Maryland, Massachusetts, Michigan, New Hampshire, New Jersey, New York, Ohio Pennsylvania, Rhode Island, and Texas. Nebraska was excluded becauses there are no investor-owned utilities in the state, and no mechanism for regulating the pass through of net power costs.
The descriptions of each state regulatory structure is sourced from S&P Capital IQ Pro (a division of S&P Global, Inc.) reports on each state commission, unless otherwised noted.