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Re: Powerex's Comments on Bonneville Power Administration's Jan 29th & 30th, 2025 Day-Ahead Market Workshops

Powerex Supports Bonneville's Decision-Making Framework

The decision to participate in a day-ahead organized market is a significant, long-term commitment that will affect trade outcomes for years, if not decades. Unlike incremental real-time markets such as WEIM and WEIS, the widespread adoption of day-ahead organized markets in the West means that virtually all generation and load will be bought and sold through centralized market processes governed by their specific market rules. As a result, most of today's existing bilateral day-ahead and real-time trading will be replaced by transactions executed within a day-ahead organized market framework. In addition to the specific transactions executed and settled in the day-ahead market, the outcomes and prices of that market will extend to forward contacts, which are often informed by the expectations of future spot market outcomes.

The result is that the terms, conditions, and pricing of approximately $25 billion in existing annual energy trade will eventually be directly or indirectly affected by the market design, rules, and the day-to-day actions of the market operators of the day-ahead organized markets in the West.

Given the profound and lasting consequences of day-ahead organized markets in the West, Powerex supports Bonneville's commitment to selecting a market with nothing short of a fully independent governance structure, an impartial market operator, and a market design that ensures confidence in fair and equitable outcomes for Bonneville and its customers, both at the start of the market and over the long term, as that market evolves.

Doing Nothing Is Not a Viable Option. BPA Should Choose Its Day-Ahead Market Now

As Bonneville nears the conclusion of its extensive day-ahead market evaluation process, it faces three choices:

1) Join EDAM,
2) Join Markets+, or
3) Do nothing and "wait and see".

Some EDAM supporters are once again pressuring Bonneville to postpone a day-ahead market decision, arguing that Pathways must first have an opportunity to progress through the California legislature. Such a delay would be a mistake for Bonneville and its customers for at least three reasons.

First, as Bonneville and many others[1] have already made clear, the Pathways Step 2.0 proposal, even if adopted, offers very limited governance changes, falling far short of the comprehensive governance changes needed for participation in a CAISO-operated day-ahead organized market to be consistent with Bonneville's threshold requirements for sound governance. For example, the proposed changes fail to address the CAISO's dual and conflicting roles as both market operator and a participating BAA. The newly proposed legislation also maintains the legal obligation for CAISO to act in the interests of California

[1] Addendum to Issue Alert 1 - Evaluation of the West-Wide Governance Pathways Initiative Step 2 Final Proposal

consumers. Moreover, neither the proposed legislation nor Pathways Step 2.0 provides a path to full independent and impartial governance of EDAM or a future west-wide RTO. Since it is now clear that the progress of Pathways falls well short of Bonneville's requirements, there is no new information to be gained from further delay.

Second, some of the requests for a Bonneville delay appear to be motivated by a desire to eliminate the competing market to EDAM, and therefore, should be viewed with an appropriate level of skepticism. Powerex fully supports each organized market seeking to attract customers by offering a platform that best meets their needs, but believes it is highly inappropriate for entities to try to coerce customers into joining EDAM by blocking competing market options.

Third, it is increasingly apparent that remaining outside of any day-ahead organized market is an untenable strategy. If most other entities in the Northwest join EDAM or Markets+, but Bonneville chooses to remain outside, Bonneville will face the prospect of rapidly declining bilateral market liquidity, since most potential counterparties will conduct their trading through the day-ahead organized markets by 2027/2028. This could significantly limit Bonneville's opportunities to cost-effectively manage the federal hydro system in the operating timeframe through market purchases and sales. At that point, Bonneville's transition to a day-ahead organized market could become a more urgent operational necessity, increasing the costs and risks that would be associated with an accelerated implementation. In short, a "wait and see" approach does not provide Bonneville with an advantage; it simply delays its entry, reduces the time available for implementation activity, and potentially increases costs and risks for Bonneville and its customers.

EDAM Is Not, and Will Not Be, an Acceptable Market Choice for Bonneville

EDAM lacks the necessary independent governance, impartial market operator and initial and evolving market design to ensure fair outcomes for Bonneville and its customers. Time and time again, stakeholders have identified EDAM/WEIM market design choices that disproportionately benefit the reliability, economic and environmental interests of California consumers at the expense of other market participants and consumers in other regions. These concerns span multiple areas including resource adequacy and sufficiency, price formation, market power mitigation, GHG attribution, reporting and pricing, and congestion rent allocation.

Some of these concerns are embedded in explicit market design rules, but others are also driven by the day-to-day operational choices of CAISO in its dual roles as both market operator and a BAA operator. Often, these decisions prioritize the specific reliability, operational or economic needs or interests of the CAISO BAA at the expense of the rest of the market footprint.[2]

As detailed in the attached paper (Appendix A) [3], a newly identified EDAM design flaw underscores these concerns. Under the EDAM design, use of the Bonneville transmission system would be subject to new charges for congestion that occurs on *other* transmission systems. These charges would be incurred even by customers delivering their energy from generation to load entirely on firm Bonneville transmission rights, and will also be incurred whenever Bonneville delivers federal power to its preference customers using the Bonneville transmission system. Unlike other day-ahead organized markets (including Markets+) where the market operator collects congestion charges and returns this revenue to entities with firm transmission rights on the constrained delivery paths, EDAM allocates those funds to the BAA where the congestion is modelled to occur. In the West, it is overwhelmingly transmission constraints inside the CAISO BAA that are congested. As a result, this flawed EDAM market design would impose new, large, and unavoidable

[2] Issue Alert 6: Market Operator Actions & Modeling
[3] PacifiCorp's Recent FERC Filing Reveals a Major EDAM Market Design Flaw

congestion costs for delivering power entirely within the Bonneville transmission system, transferring value from Bonneville power and transmission customers to the CAISO's own customers.

This anomalous market design choice is now memorialized in the EDAM Tariff, but it did not receive much attention during the EDAM development phase, as it was widely understood that deliveries using firm transmission service would receive protection from day-ahead congestion charges.[4] It was only when PacifiCorp filed its proposed amendments to its OATT with FERC on January 16, 2025 that it came to light that firm transmission would be charged—with no protection whatsoever—for congestion costs on other transmission systems. The fact that such a significant departure from the EDAM Final Proposal—as approved by the CAISO Board of Governors— was only identified at this late stage underscores the serious governance and oversight concerns with the California ISO that Bonneville and other entities have long expressed.

Like many of the specific market design differences that are not captured in production cost models, this newly identified EDAM design flaw was overlooked in all of the published EDAM benefit studies to date. As a result, these studies — including any comparison to Markets+ — are fundamentally flawed as they miscalculate and/or misallocate congestion revenue and thus fail to provide any meaningful assessment of EDAM participation.

Bonneville Should Commit to Join Markets+

Powerex strongly supports Bonneville staff's previously expressed preference for Markets+. This preference reflects a thorough assessment of Bonneville's statutory obligations, each market's governance, oversight, and initial design, and includes both quantitative and qualitative considerations.

The differences between EDAM and Markets+ are clear in each category of governance, initial market design, and daily operations. Unlike EDAM, Markets+ is built on a fully independent governance framework, including an independent governing body and a stakeholder-driven market design process. This foundation has fostered unprecedented collaboration and consensus among a broad and diverse group of western stakeholders, resulting in an initial market design and tariff that delivers economic, reliability, and environmental benefits for all participants—including Bonneville and its customers.

Equally important, Markets+ offers durable confidence in its governance, oversight and future evolution of the market design. As the grid continues to evolve, so will each of the energy markets. Markets+ is the only western organized market available to Bonneville that ensures future market design changes will uphold fair and equitable outcomes for Bonneville and its customers.

Furthermore, Markets+ is the only option with a fully independent and impartial market operator. In its daily operations, SPP will be accountable for the market as whole, ensuring that its day-to-day actions deliver economic, reliability, and environmental outcomes that are equitable across all states and regions.

Powerex appreciates Bonneville's ongoing leadership in developing a western day-ahead organized market that best serves Bonneville, its power and transmission customers, and the broader region. Powerex urges Bonneville to reaffirm this leadership by committing to join Markets+.

[4] EDAM Final Proposal, at page 15, 34, and 58.

Appendix A

PacifiCorp's Recent FERC Filing Reveals a Major EDAM Market Design Flaw

The transmission systems of PacifiCorp, NV Energy and Idaho Power enable electricity to be delivered between the solar-rich, summer-peaking Southwest and the hydro-rich, winter-peaking Northwest. EDAM participation would expose all of these deliveries to hourly congestion charges that drive market price differences between these regions. Contrary to all other day-ahead organized markets, EDAM will not return these day-ahead congestion charges back to customers with firm transmission service, including those that pay the charges. Instead, EDAM will deliver those congestion revenues to entities based on the location of the congestion bottlenecks, which extensive data shows is primarily on the California ISO's transmission system.

The PacifiCorp, NV Energy and Idaho Power transmission systems are the most exposed to this outcome, including when the utilities use their own transmission systems to deliver their own generation to their own load. ***The magnitude of this value shift could reach as high as $1 billion per year in a high solar penetration case.***

Electricity deliveries between the solar-abundant, summer-peaking Southwest and the hydro-abundant, winter-peaking Northwest are among the most valuable in the Western region. Prices between the two regions are often very different: prices in the Southwest are typically lower during solar hours while prices in the Northwest are typically lower outside of solar hours when there is excess hydro or wind. Prices between these regions can also diverge greatly during Northwest cold snaps and during Southwest summer heat waves. As solar installations continue to be added, these price differences are growing and occurring in more hours. These North-to-South and South-to-North price separations occur for distant deliveries that span multiple transmission service providers' territories, but also occur for shorter-distance deliveries of generation to load entirely within the individual service territories of the California ISO, PacifiCorp, NV Energy and Idaho Power.

Under the OATT framework for transmission service—which is not being changed by day-ahead organized markets—entities that invest in firm OATT transmission service obtain the right to deliver generation from lower-price locations to load in higher-price locations.

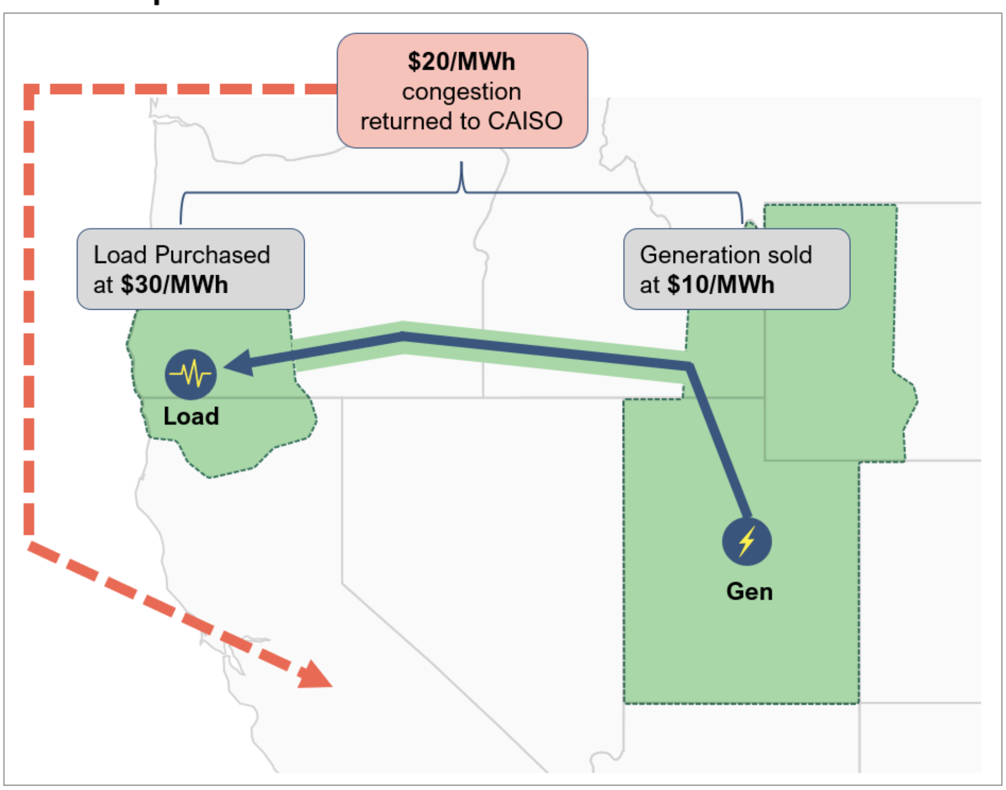
EDAM will be layered on top of this OATT framework of transmission rights, and will require each generator and each import to sell their supply at a locational price, and each demand and each export to pay a different locational price. All deliveries, including those using firm OATT transmission service, will therefore now face a net financial settlement in EDAM based on the price difference between the location of their generation (or import) and the location of their load (or export). This is a standard part of how other day-ahead organized markets have been implemented. Critically, however, all other day-ahead organized markets in the U.S. provide—and FERC requires—a financial hedge that returns the day-ahead congestion charges on a delivery path back to the entities with firm transmission rights on that delivery path.

But EDAM will <u>not</u> return congestion charges back to the entities that hold firm OATT rights. Instead, EDAM will allocate congestion revenues based on the modeled locations of congestion "bottlenecks."

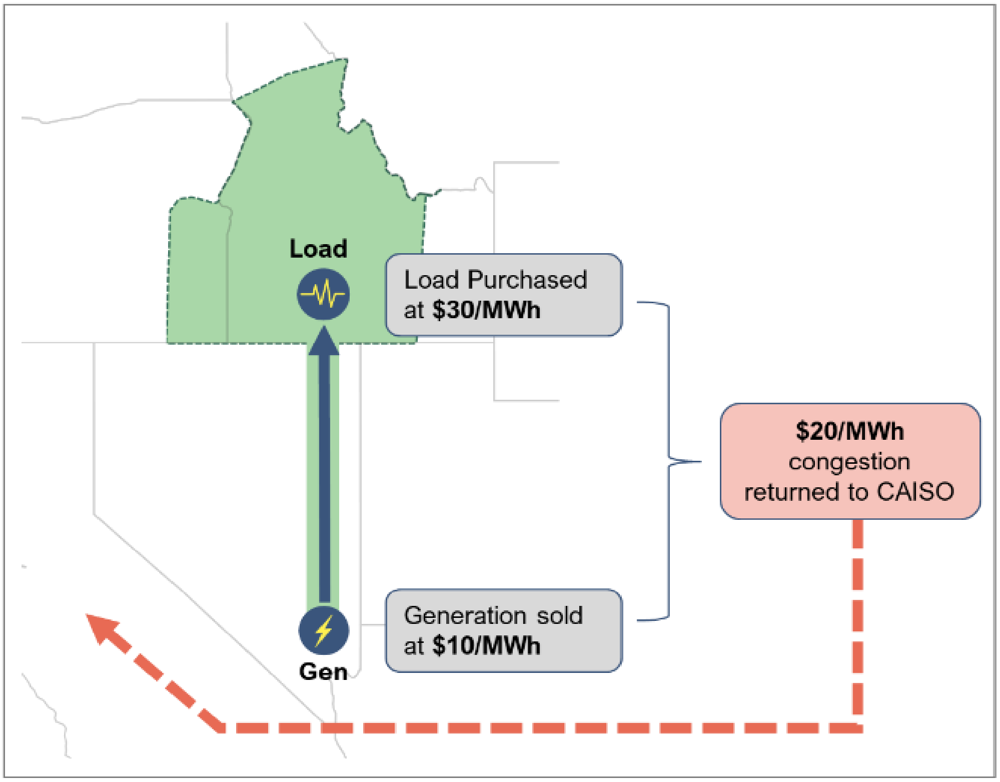
Data on congestion in the Western EIM—which models physical flows of electricity using full information on all final transmission flows from all participating TSPs, including all day-ahead schedules—reveals that the most prevalent congestion "bottlenecks" in the western grid are located in the California ISO's transmission system. Under the EDAM design, this means *the California ISO's customers* can be expected to receive the vast majority of the flow-based congestion charges collected from activity *on other transmission systems* throughout the EDAM footprint.

This EDAM market design flaw will have the greatest impact on those adjacent transmission systems outside of California that also provide significant North-to-South and South-to-North connectivity: namely, PacifiCorp, NV Energy and Idaho Power. If each of these utilities join EDAM under its current design, it will be the California ISO's own customers that will collect the vast majority of the locational price difference from activity on the PacifiCorp, NV Energy and Idaho Power transmission systems. This outcome is illustrated below using a numerical example of $20/MWh of flow-based congestion charged between generation and load outside of California that is a result of transmission constraints in the California ISO service territory:

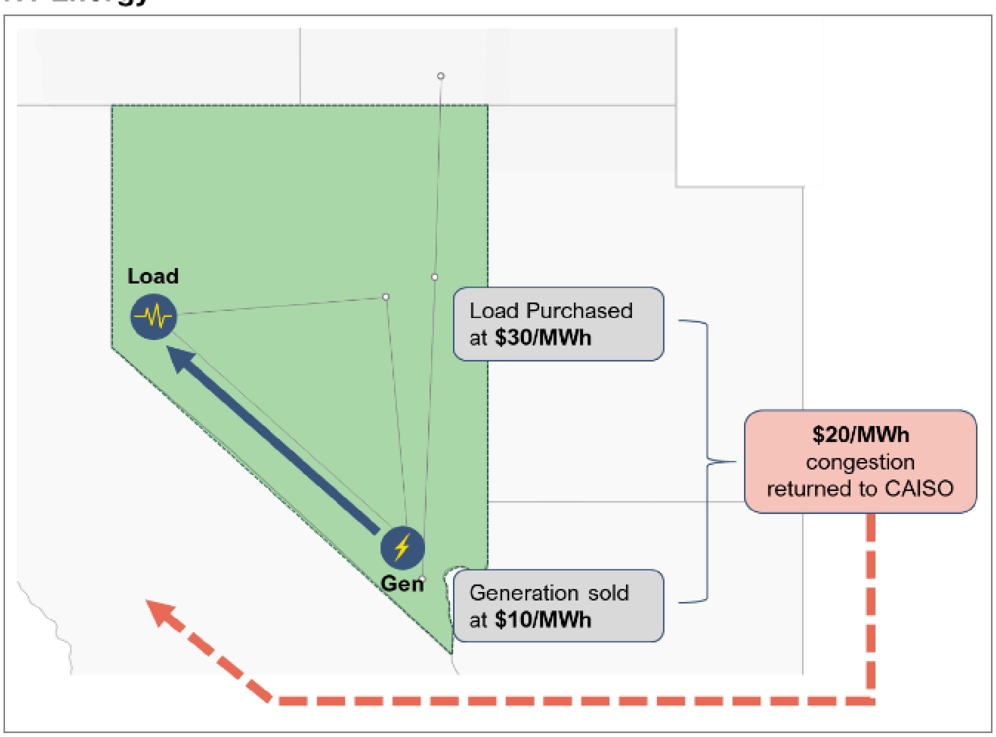
PacifiCorp



Idaho Power



NV Energy



Powerex's analysis shows that moving forward with participating in EDAM under its current design would result in a transfer of value from PacifiCorp, NV Energy and Idaho Power's retail ratepayers and other transmission customers that could reach as high as $1 billion per year.

This transfer of value can be expected to have a wide range of harmful consequences in the service territories of PacifiCorp, NV Energy, Idaho Power, and beyond, including:

1. Imposing large new costs to these utilities' retail ratepayers;
2. Largely eliminating the incentives for third parties to invest in firm transmission service;
3. Shifting a significant portion of the benefits of key transmission expansion projects such as the SWIP, Greenlink and Gateway projects to the California ISO's own customers;
4. Discouraging the procurement of the least-cost, best-fit resources in the West, particularly in circumstances that require use of an EDAM transmission provider's system; and
5. Undermining the proper functioning of other regional programs and markets, including the Western Resource Adequacy Program (WRAP) and Markets+.

Since most stakeholders, including potential EDAM participants, appear to have only become aware of this critical design flaw following PacifiCorp's January 16 FERC filing, these harmful consequences have not been considered in any evaluation or study of EDAM participation to date.

The attached set of Frequently Asked Questions shares Powerex's understanding and its analysis of this critical EDAM design flaw, how it deviates from all other day-ahead organized markets, the outcomes and harmful consequences that can be expected, and potential solutions to protect ratepayers and transmission customers.

EDAM Design Flaw: Frequently Asked Questions

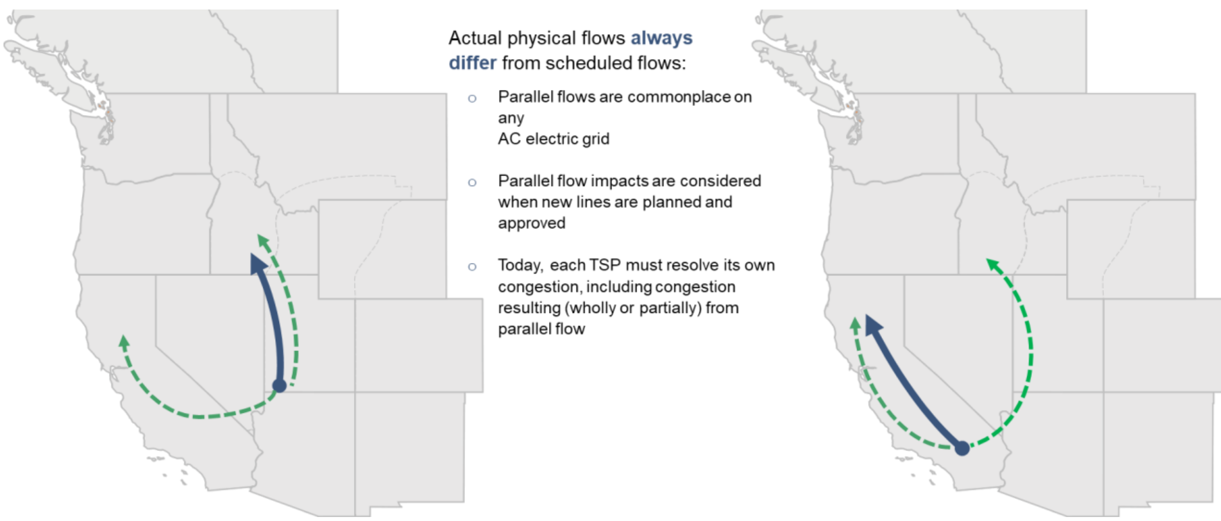
<u>What is the specific market design issue that creates these problematic outcomes?</u>

In EDAM, like in other day-ahead organized markets, all deliveries between two locations will be financially settled as:

- A sale at the Locational Marginal Price (LMP) at the location of the generation or import; and
- A purchase at the LMP at the location of the load or export.

If the LMPs at the two locations are different, the delivery will be exposed to a net financial settlement equal to this price difference for the entire quantity of the delivery. LMPs between any two locations will be different if there is modeled congestion anywhere in the EDAM footprint that prevents additional electricity from flowing between the two locations.

Under the OATT framework, transmission providers sell "contract path" service up to the rated capability of that path. It is well known that the physical electricity flows associated with a scheduled delivery do not follow the "contract path," and frequently also flows on neighboring transmission systems, known as "parallel flows".



Parallel flows are not new, and occur routinely on all AC power systems, including in the West. In all market designs ***other than EDAM,*** customers that use transmission service from one TSP ***are not liable for*****, or can otherwise *****mitigate the cost of*****, parallel flows on other transmission systems**, as shown below:

Scenario	Scheduled Delivery	Parallel Flow System	Parallel Flow Congestion Charged?	Mitigation
Outside Organized Markets	TSP 1	TSP 2	**NO**	Not Required
ISO/RTO Day Ahead	ISO/RTO Transmission Owner 1	ISO/RTO Transmission Owner 2	YES	Congestion charges return to load via financial transmission rights from source to sink
ISO/RTO Real-Time	ISO/RTO Transmission Owner 1	ISO/RTO Transmission Owner 2	YES	Can be avoided through scheduling day-ahead
Western Energy Imbalance Market (WEIM)	WEIM TSP 1	WEIM TSP 2	YES	Can be avoided through advance scheduling
Western Energy Imbalance Service (WEIS)	WEIS TSP 1	WEIS TSP 2	YES	Can be avoided through advance scheduling
Markets+	Markets+ TSP 1	Markets+ TSP 2	YES	Congestion charges returned to firm transmission rights holder by market operator
EDAM	EDAM TSP 1	EDAM TSP 2	YES	**NO**

EDAM is an aberration from the design of all other day-ahead organized markets, including Markets+, because it applies congestion charges in a manner that is not aligned with how it returns that congestion revenue back to participating entities.

As shown in the table above, EDAM will charge for congestion on scheduled deliveries of participating TSPs based on the difference in LMPs between the source and sink of the delivery, reflecting any parallel flows on other transmission systems. But, unlike other day-ahead organized markets, including Markets+, EDAM will not protect the firm transmission customers of each TSP for the physical flows modeled to occur outside of its system, thereby ignoring that the TSP's defined entitlements include creating parallel flows on adjacent transmission systems.

This is the critical issue that came to light only after PacifiCorp's January 16 FERC filing, in which it proposed to provide customers scheduling on firm PacifiCorp OATT rights a "partial hedge" against the EDAM congestion charges they would incur. Namely, the "partial hedge" would reverse only the portion of congestion price differences related to transmission constraints modeled within PacifiCorp's transmission system, even though the schedules would pay congestion charges that also include parallel flows on other transmission systems. In practice, the effectiveness of the "partial hedge" proposal would depend on whether differences in LMPs are primarily the result of transmission constraints in PacifiCorp's system, or constraints on a different EDAM participant's system.

Experience in the Western EIM—which performs economic dispatch in real-time but reflects all final transmission flows, including from day-ahead schedules—shows unambiguously that the flow-based transmission constraints that most often limit physical flows between locations *throughout the organized market footprint* are constraints located in the California ISO transmission system. This occurs in a large number of hours across the year, and occurs during periods of prevailing Northbound flows and during periods of prevailing Southbound flows.

Since the EDAM design distributes congestion charges based on the location of the constraints that cause LMPs to separate, and data shows these constraints will predominantly be located in the California ISO's transmission system, **once EDAM commences customers that use PacifiCorp transmission service will pay large new congestion charges that will go almost entirely to the California ISO's own customers.**

What transmission systems will be affected by this EDAM design?

All transmission providers that participate in EDAM will expose their retail ratepayers and their transmission customers to paying new charges for congestion on other EDAM transmission systems. The EDAM design is likely to have the greatest impact on the transmission systems that provide North/South connectivity outside of the California ISO. Deliveries on these systems create parallel flows over the North/South facilities operated by the California ISO (and vice versa), and are therefore most likely to experience LMPs that separate due to constraints in the California ISO's system. Deliveries using transmission service from PacifiCorp—as well as from NV Energy and Idaho Power, if those utilities move forward with participation in EDAM under its current design—are therefore most vulnerable to paying frequent, large and volatile new EDAM congestion charges that go to the California ISO's own customers.

Is this value transfer justified and reflective of costs incurred?

Absolutely not. The congestion charges that will be paid by customers that use PacifiCorp transmission service and allocated to the California ISO's own customers are not a reimbursement of costs actually incurred by the California ISO (or its own customers), for at least two reasons. Under the EDAM design, LMP price differences will be applied to the full quantity of energy delivered using firm transmission service on external TSPs in EDAM, which is likely to greatly exceed any redispatch of generation to manage congestion in California. For example, the California ISO may collect congestion revenue from external transmission use on 3,000 MW of deliveries, even if this only requires 100 MW of redispatch of generation. Second, the generation that is being re-dispatched in EDAM may not even be located in the California ISO's service territory.

This value shift is the result of EDAM's unique design, which provides an inappropriate windfall to customers of transmission providers that have not built out their system to alleviate "bottlenecks" at the direct expense of customers of transmission systems that have made the often large investments necessary to upgrade their systems and eliminate "bottlenecks."

Customers that use NV Energy's or Idaho Power's transmission systems would be exposed to this same value shift if those utilities were to move forward with EDAM participation under the current EDAM design.

Is data from the Western EIM relevant to understanding congestion in EDAM?

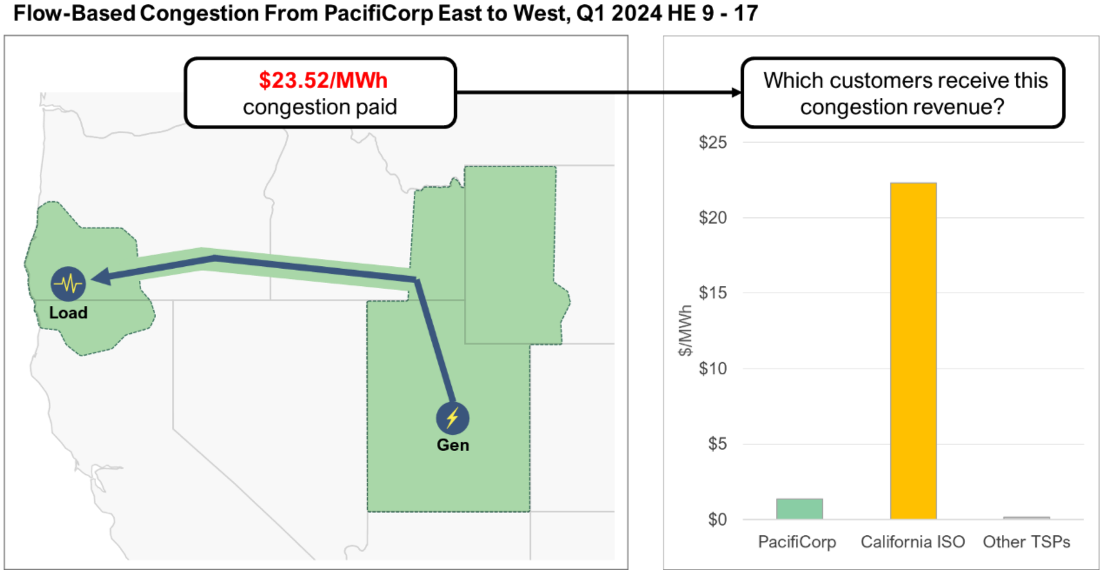
Yes. The Western EIM includes the same generation, load, and transmission systems, and also uses the same modeling and software tools, as will be used in EDAM. The Western EIM uses full information on all final transmission flows from all participating TSPs, including all day-ahead schedules as well as all intra-day schedules submitted to the Western EIM. While the LMPs calculated in the Western EIM are used to financially settle only a limited volume of real-time imbalance transactions, the LMPs and congestion charges, on a per unit basis, reflect the complete set of all uses of the transmission network each hour.

Moreover, EDAM is an extension of the California ISO's day-ahead market, which is designed to produce locational prices that closely track the results in the California ISO's real-time market (of which the Western EIM is part). Day-ahead and real-time market outcomes can differ in individual hours due to changing conditions, but the results should be highly aligned when viewed across days, months and years. For this reason, data on price outcomes in the Western EIM provide an excellent indicator of the outcomes that can be expected in EDAM.

What is the potential magnitude of value, in $/MWh, that could be re-distributed from PacifiCorp, NV Energy or Idaho Power's transmission systems to the California ISO's under the EDAM design using recent market prices in the Western EIM?

Using Western EIM data for 2024 Q1[1], delivering generation from PacifiCorp's East service territory to load in PacifiCorp's West service territory during the solar hours would have incurred charges for flow-based congestion of approximately $23.52/MWh. Approximately 94% of these congestion charges would be allocated to the California ISO and its own transmission customers, under the EDAM market design.

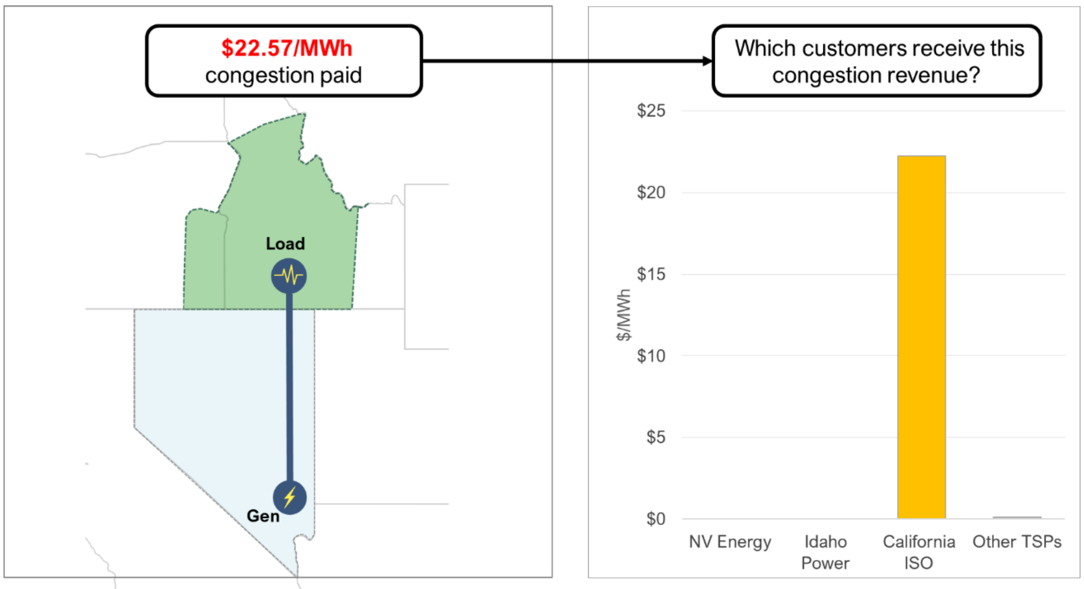
Flow-Based Congestion From PacifiCorp East to West, Q1 2024 HE 9 - 17



[1] Powerex's analysis uses the California ISO Department of Market Monitoring Quarterly Reports on Market Issues and Performance for Q1, Q2 and Q3 2024, as well as CAISO OASIS data of binding constraints in the Western EIM.

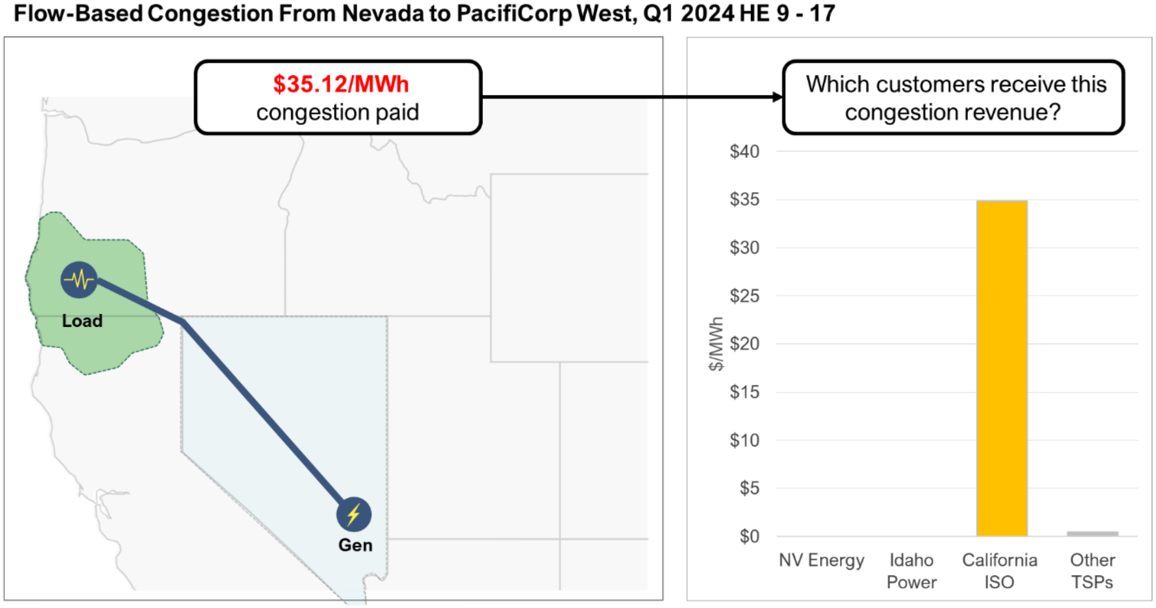
This same analysis was performed for a delivery of generation in Nevada to load in Idaho Power's service territory during the solar hours. This delivery would have incurred charges for flow-based congestion of $22.57/MWh during 2024 Q1, nearly all of which would be allocated to the California ISO under the EDAM market design.

Flow-Based Congestion From Nevada to Idaho, Q1 2024 HE 9 - 17



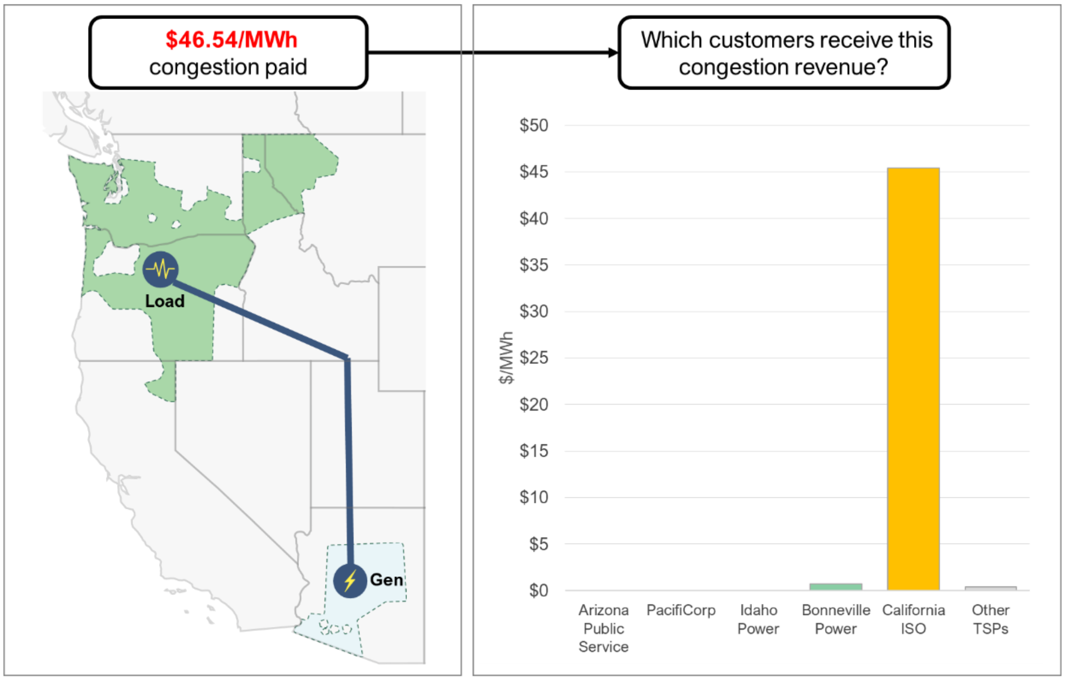
A delivery of generation from Nevada to load in PacifiCorp's West service territory during the solar hours would have incurred charges for flow-based congestion of $35.12/MWh during 2024 Q1, nearly all of which would be allocated to the California ISO under the EDAM market design.

Flow-Based Congestion From Nevada to PacifiCorp West, Q1 2024 HE 9 - 17



A delivery of generation from Arizona to load in Bonneville Power's service territory during the solar hours (on transmission service outside of California) would have incurred charges for flow-based congestion of $46.54/MWh during 2024 Q1, nearly all of which would be allocated to the California ISO under the EDAM market design.

Flow-Based Congestion From Arizona to Bonneville Power, Q1 2024 HE 9 - 17



<u>Will the EDAM market design only impact deliveries from the Southwest region all the way to the Northwest region (or vice versa)?</u>

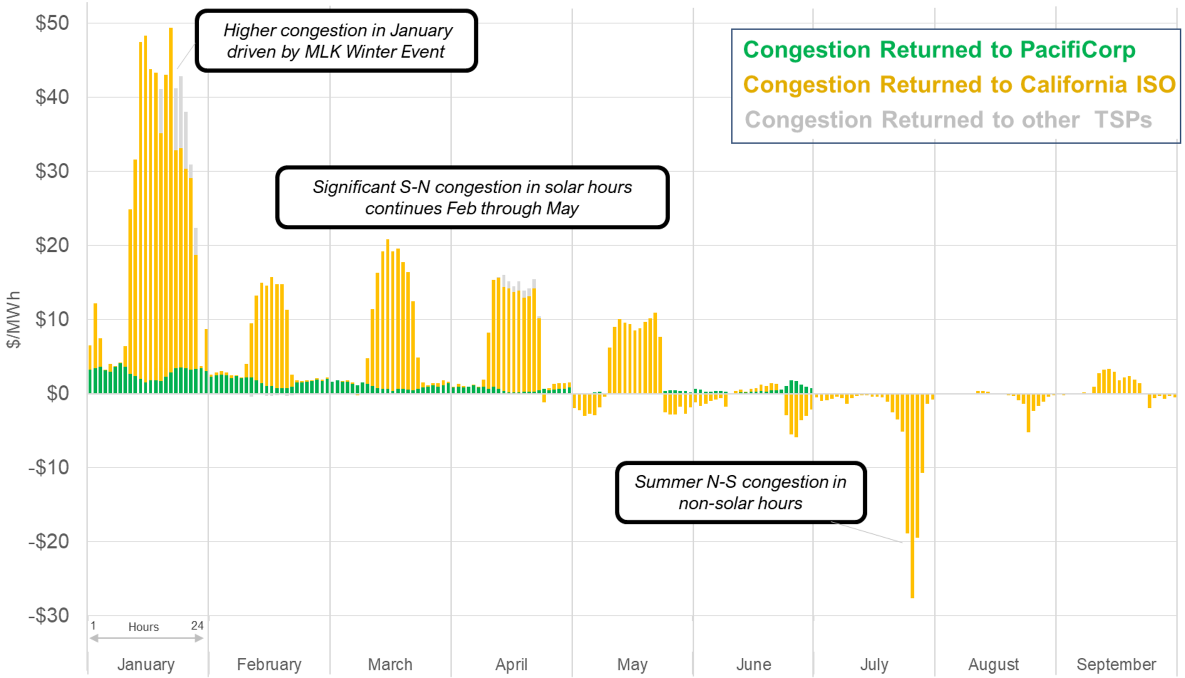
No. While each of the above scenarios is based on the average congestion costs for deliveries between two transmission service territories (a limitation based on the currently available data), similar outcomes can be expected for South-to-North deliveries entirely within each of these transmission service providers' systems.

All deliveries on every transmission system will be exposed to LMP differences, even for deliveries that are for relatively short distances and entirely within the same system.

<u>Do congestion patterns change across the year, making EDAM congestion charges and revenues generally neutral for TSPs?</u>

No. Powerex's analysis of Western EIM data shows this result is not unique to Q1, or to the solar production hours. The chart below shows the average flow-based congestion charges between PacifiCorp East and PacifiCorp West for each hour across the first nine months of 2024.

Flow-Based Congestion From PacifiCorp East to West, January – September 2024



The positive values in the chart reflect South-North congestion and the negative values reflect North-South congestion. Both the positive and negative values in the chart above would be returned as positive revenue to the respective transmission service provider and its customers (as applied to flows in the respective direction). The chart shows that congestion was in the South-to-North direction and concentrated in the solar hours in the winter and spring months, but in the summer months is in the North-to-South direction outside the solar hours. Regardless of direction, it is systematically constraints in the California ISO that cause LMPs to separate in the West and would result in customers using PacifiCorp's transmission system paying large congestion charges to the California ISO's customers.

Are the locations of congestion likely to be materially different in the future?

No. To the contrary, the underlying drivers of current congestion patterns are likely to be exacerbated in the coming years. The California ISO has added extensive solar capacity in Southern California in the past several years. Frequent congestion during the solar hours *on constraints inside California* indicate that transmission capability within California has not been expanded sufficiently to enable all of this new solar supply to be delivered to Northern California or beyond, however. In contrast, PacifiCorp, NV Energy and Idaho Power are also adding significant new solar generation, and they are each also pursuing major transmission expansion projects to increase the transfer capability *outside of California* to deliver this supply Northbound, such as the Gateway, SWIP and Greenlink projects.

Given these investments in generation and transmission expansion in the PacifiCorp, NV Energy and Idaho Power service territories, it can be expected that ***the California ISO grid will***

continue to be the principal "bottleneck" to electricity flows between the Southwest and the Northwest, in both directions.

This conclusion is consistent with analysis conducted by Brattle in its December 2023 EDAM participants benefits study, which shows that the California ISO transmission system will be the source of the vast majority of congestion in EDAM in 2032, accounting for $1.5 billion of congestion out of a total of $2.15 billion.

Price differentials between the Northwest and Southwest—as well as EDAM's transfer of value of other transmission systems to the California ISO's customers—can be expected to grow over the foreseeable future, as a result of two prevailing factors. First, the integrated resource plans of entities throughout the Southwest show a continued and sizeable buildout of new solar generation. This can be expected to drive larger Northbound price separation during a higher fraction of solar production hours. Second, the increased solar generation can be expected to shift more Northwest hydro production into other hours, leading to Southbound price separation in a growing number of non-solar hours.

What is the potential magnitude in future years of the total value of deliveries using the PacifiCorp, NV Energy or Idaho Power system that will be captured by the California ISO's own customers under the EDAM design?

The range of charges for flow-based congestion observed in the Western EIM for 2024 can be applied to the current and projected future South-to-North and North-to-South transfer capability on the PacifiCorp, NV Energy and Idaho Power systems to estimate the value of these deliveries. Western EIM congestion data from 2024 on a per MWh basis can also be used to estimate how much of that value would be captured by the California ISO under the EDAM design.

As shown in the tables below, an indicative range of the aggregate value that is susceptible to being shifted from ratepayers and transmission customers of PacifiCorp, NV Energy and Idaho Power and instead will go to the California ISO's own customers and could reach $1 billion per year under a scenario with high solar penetration.

Potential Parallel Flow Costs to CAISO BAA (Illustrative)

Solar Hours (8 hours/day)

Non-CAISO Transmission Northbound (Idaho/NV Energy/PacifiCorp)	Total	Average Congestion Cost $10/MWh	$20/MWh	$30/MWh	$40/MWh
Existing S-N Idaho/NV Energy/PacifiCorp	~2,300 MW	$67M	$134M	$201M	$269M
+ SWIP Line – Idaho Share	~500 MW				
+ SWIP Line – NV Energy Share	~850 MW				
+ Greenlink – NV Energy	~1525 MW				
Future S – N:	**~5,175 MW**	**$151M**	**$302M**	**$453M**	**$604M**

Non-Solar Hours (16 hours/day)

Non-CAISO Transmission Southbound (Idaho/NV Energy/PacifiCorp)	Total	Average Congestion Cost $5/MWh	$10/MWh	$15/MWh	$20/MWh
Existing N-S Idaho/NV Energy/PacifiCorp	~2,400 MW	$70M	$140M	$210M	$280M
+ SWIP Line – NV Energy Share	~950 MW				
Future N – S:	**~3,350 MW**	**$98M**	**$196M**	**$293M**	**$391M**

These values are broadly consistent with Brattle's December 2023 EDAM participants benefits study, which projects that approximately $1.5 billion per year of future EDAM congestion would be associated with constraints on the California ISO system, out of total EDAM congestion of $2.15 billion.

Notably, however, Brattle's analysis did not correctly identify which customers would receive these congestion revenues under the EDAM design.

Is this the same issue that was raised during the January 2024 winter weather event?

No, this EDAM market design issue represents a new form of misallocation of congestion revenue. During the January 2024 winter weather event, it was the scheduling limits on the California Oregon Intertie (COI) that limited the quantity of electricity that could be scheduled on the jointly-owned, multi-state Pacific AC Intertie northbound. Even though the scheduling limit was limited by physical flow limits that were actually in Oregon, the California ISO modeled it as a limitation on exports out of its system, resulting in the California ISO collecting over $100 million in congestion charges over a five-day period. That issue, however, was related to the allocation of the value of deliveries that are scheduled on the Pacific AC intertie, not parallel flow congestion.

The EDAM design raises an entirely new concern related to the allocation of the value of deliveries that are not scheduled using the California ISO transmission system at all. That is, the value of deliveries scheduled on the transmission systems of PacifiCorp, NV Energy or Idaho Power will now also be largely allocated to the California ISO's customers, due to the misallocation of parallel flow congested revenues.

Why was this issue not identified sooner?

There were two reasons the issue was not identified sooner.

First, throughout the EDAM stakeholder process, the California ISO communicated repeatedly the concept of firm transmission rights receiving a financial hedge to offset day-ahead congestion charges. One specific presentation by the California ISO included discussion of a "perfect hedge."[2] The expectation that OATT firm transmission rights would be hedged against EDAM congestion charges was further reflected in the EDAM Final Proposal approved by the California ISO Board of Governors:

> *As discussed below, transmission customers can also utilize their transmission rights and pair their transmission rights with a self-schedule. This reflects that the participant submitting a generation self-schedule wants the resource's output to flow and that it has existing transmission rights – whether under the OATT or legacy arrangements – to deliver that generation. This pairing of existing transmission rights and a self-schedule ensures through settlements that the participant exercising these rights is not charged for transmission and is held harmless for the congestion component between source and sink.*[3]

> *Self-schedules supported by transmission rights may be afforded a hedge against marginal congestion differences between the network locations of their sources (supply) and their sinks (demand), which would mitigate potential exposure to congestion price differences, either positive or negative, between the source and the sink.*[4]

> *Throughout the discussion of the transmission commitment design, the proposal has alluded to the exercise of ETC/TOR functionality to enable the transmission customer to exercise its OATT (or legacy) transmission rights and also obtain the hedge on the congestion.*[5]

Second, the numerical examples provided by the California ISO during the EDAM stakeholder process discuss price separation within a BAA being caused entirely by constraints within that same BAA. ***Powerex has not found any instance during the EDAM stakeholder process in which the California ISO presented the far more common and realistic circumstance of price separation in a BAA being due to parallel flow and constraints within a different BAA.*** This is the precise condition that causes the value of external transmission systems to be shifted to the California ISO's own customers, but, to the best of Powerex's knowledge, this condition was not raised with stakeholders.

[2] *See* Mar 17, 2022 Meeting of EDAM Working Group 2, slide 18.
[3] EDAM Final Proposal, at 15.
[4] EDAM Final Proposal, at 34.
[5] EDAM Final Proposal, at 58.

<u>Has this market design flaw been accurately reflected in any EDAM studies?</u>

No. All of the EDAM benefits studies to date have completely missed this important market design issue, and given its magnitude, the results of these studies are completely meaningless.

Some of the EDAM benefits studies that have been published do not simulate physical power flows (and instead apply a "contract path" model), and therefore cannot identify the specific flow-based transmission constraints that will drive EDAM congestion prices. Those EDAM benefits studies that do model physical power flows did identify constraints located in the California ISO transmission system as the primary cause of congestion price differences in EDAM (*e.g.,* Brattle's December 2023 EDAM participants benefits study as shown below with California ISO constraints highlighted):

Day-Ahead Congestion on Paths with Largest Changes ($ Millions)

Path	Base Congestion	EDAM Congestion	Change	% Change
P61 Lugo-Victorville 500 kV Line	$436	$473	$37	8.6%
P66 COI	$219	$248	$30	13.7%
P26 Northern-Southern California	$618	$642	$23	3.8%
P28 Intermountain-Mona 345 kV	$121	$135	$15	12.3%
P15 Midway-LosBanos	$115	$127	$13	11.2%
P75 Hemingway-Summer Lake	$96	$107	$11	11.7%
P46 West of Colorado River (WOR)	$24	$31	$6	25.5%
P20 Path C	$10	$14	$3	31.8%
P16 Idaho-Sierra	$9	$11	$2	22.7%
P30 TOT 1A	$20	$13	-$7	-35.5%
P36 TOT 3	$22	$14	-$8	-35.6%
P47 Southern New Mexico (NM1)	$118	$92	-$26	-22.0%
Total Change (All Paths)	**$2,041**	**$2,150**	**$109**	**5%**

Note: Total includes all WECC paths, but only paths with changes in congestion of $10 million or more are shown.

Source: Extended Day-Ahead Market Participation Benefits Study, December 2023

However, while Brattle's EDAM benefits studies appear to reasonably identify the major causes of congestion in EDAM, it appears that they do not allocate EDAM congestion revenues to the BAA where the constraints are located, as required by the EDAM market design. For example, in a September 2024 EDAM benefits study, ***Brattle projects that PacifiCorp would receive $141 million per year in EDAM congestion revenue. But under the actual EDAM design, this would be a large <u>cost</u> since PacifiCorp would frequently pay congestion charges to the California ISO when it moves power on its own system*** from South to North or North to South.

Brattle projects extensive deliveries of electricity from PacifiCorp-East to PacifiCorp-West; from Idaho Power to PacifiCorp-West; and from NV Energy to PacifiCorp-East. These are the very deliveries that will incur congestion charges due to flow-based constraints in the California ISO, with the EDAM market design allocating the value of those deliveries predominantly to the California ISO's own customers.

Brattle's description of how congestion charges will be allocated in EDAM provide further indication that this critical EDAM design flaw has not been accurately recognized in its benefits studies. In an October 2024 paper comparing how congestion revenues would be distributed by Markets+ and by EDAM, Brattle stated that "the two approaches may not end up materially different, ***depending on the suballocation approaches implemented by EDAM member***

BAAs." But the larger issue is not in the "suballocation" of congestion revenues by EDAM participants like PacifiCorp, but the allocation of congestion revenues by the EDAM market operator to those participants in the first place. The same misunderstanding of the EDAM market design appears in Brattle's conclusion that "receiving the congestion revenues according to ownership of transmission rights (the Markets+ approach) will be similar to receiving congestion from within their own BAA (the EDAM approach)."[6]

<u>How will the EDAM design harm retail ratepayers of PacifiCorp, and potentially also the retail ratepayers of NV Energy and Idaho Power if those utilities join EDAM?</u>

The largest use of each of these transmission systems is by the utility itself, which uses its system to deliver its generation to its customers. Each of these utilities that participates in EDAM under its current design would face new large congestion charges from financially settling their generation and their load at different EDAM LMPs. But very little of the congestion charges collected by the EDAM market operator can be expected to be returned to these utilities, since it will largely be transmission constraints on the California ISO system that are responsible for separation in LMPs. ***The end result is that PacifiCorp's retail ratepayers will pay not only for the cost of PacifiCorp's generation and PacifiCorp's transmission system, but also will pay a new congestion charge to the California ISO for the deliveries scheduled on PacifiCorp's transmission system.*** The same will occur for NV Energy's retail customers and for Idaho Power's retail customers, should those utilities join EDAM.

<u>Will other load customers that use PacifiCorp, NV Energy or Idaho Power transmission system be harmed by this issue as well?</u>

Yes. Retail choice and retail access customers located in those service territories will also financially settle their load at a different LMP than their generation. Even if these customers receive a "partial hedge," they will still incur new charges for congestion associated with constraints on the California ISO transmission system.

In addition, utilities and other load-serving entities located outside of the PacifiCorp, NV Energy or Idaho Power service areas, but that use transmission service across those systems to deliver Northwest generation to the Southwest, and/or deliver Southwest generation to load in the Northwest, will also be adversely affected.

<u>How will the EDAM market design affect investment in transmission service?</u>

Participants in EDAM will continue to sell transmission service under the OATT framework. But the EDAM market design flaw can be expected to largely eliminate the incentives that unaffiliated transmission customers may have to invest in firm OATT service on transmission systems that participate in EDAM. Unlike every other day-ahead organized market, EDAM does not provide firm OATT transmission rights a financial hedge against day-ahead congestion

[6] Brattle, "The Proposed Day-Ahead Markets in the WECC: A Comparative Assessment Of EDAM And Markets+ Design Features", October 2024, at pp. 26-27.

charges. Even the “partial hedge” proposed by PacifiCorp—which PacifiCorp has explained is as far as it can go given the EDAM design—provides no protection against charges for congestion on the California ISO transmission system, which is expected to constitute the large majority of day-ahead congestion charges applied from use of the PacifiCorp transmission system. As a result, customers that invest in firm OATT transmission service will often be in no better position than customers that do not invest in firm service, and instead simply rely on selling their generation to EDAM and/or purchasing energy for their load from EDAM.

The erosion of incentives for unaffiliated customers to invest in firm OATT transmission service can be expected to lead to a loss of third-party transmission revenues for transmission providers that participate in EDAM under the current design. This, in turn, would require a corresponding increase in transmission costs borne by network load customers in those service areas.

In addition, unaffiliated customers will have far less incentive to request firm OATT transmission service that requires upgrades to or expansion of the transmission system. The identification of valuable upgrades, as well as the funding for these upgrades, can be expected to shift entirely to network customers as well.

How will this market design issue affect the development of new generation?

Independent power producers can be expected to face challenges finding a load-serving entity willing to enter into a long-term commitment to receive the output of a generation facility if that output must be delivered using transmission service from PacifiCorp, NV Energy or Idaho Power, if each of those transmission systems participate in EDAM under its current design. Those deliveries would be exposed to EDAM congestion charges, which can undermine the economic viability of the project and create financial risk that neither the IPP nor the LSE may be able to accept.

How will this market design issue affect WRAP?

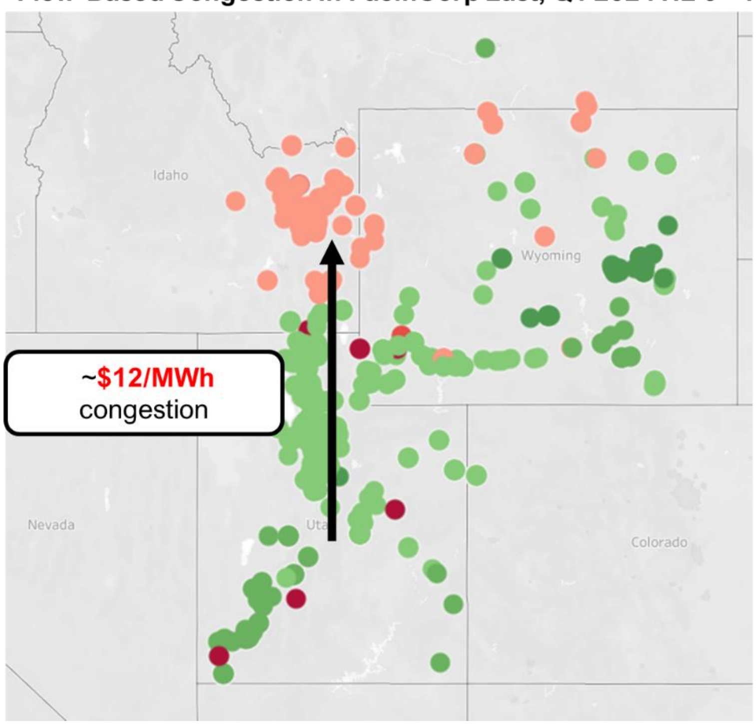
WRAP Participants can be expected to face increased costs and/or reduced options for procuring the supply necessary to meet their Forward Showing requirements, since supply requiring transmission service exposed to frequent, large and volatile EDAM congestion charges will be unworkable for many entities. This includes not only the use of remote resources but also seasonal supply arrangements between winter peaking and summer peaking WRAP participants. The diminished supply options may prevent some WRAP Participants from committing to binding operations due to the risk of financial penalties for any Forward Showing deficiency.

What PacifiCorp transmission paths will be most affected by these charges?

PacifiCorp has rights to and uses a large quantity of transmission service on its own system between PacifiCorp-West and PacifiCorp-East, which is one of the most valuable transmission paths in the West. PacifiCorp is also expanding the connectivity between its systems by making significant investments, including the Boardman-to-Hemingway project and the multiple

Gateway projects. ***If PacifiCorp joins EDAM under its current design, PacifiCorp will now need to pay frequent, large and volatile congestion charges, which will go to California ISO customers, in order to use its long-held service on its own system as well as to use the new projects it is investing in.*** The specific magnitude of these charges will vary depending on the specific location of the generation and of the load being served, as well as the grid conditions when those deliveries occur, but Powerex's analysis of data from the Western EIM indicates these charges can often be expected to be substantial. In 2024 Q1, the flow-based congestion charges on deliveries from PacifiCorp-East to PacifiCorp-West during the solar hours averaged $23.57/MWh, of which approximately 94% were due to constraints in the California ISO and would go to the California ISO's own customers under the EDAM market design. The congestion occurring during this period was not limited to transfers between PacifiCorp's East and West BAAs, however. The chart below shows approximately $12/MWh of flow-based congestion in the South-North direction occurred entirely within the PacifiCorp East service area during the solar hours in 2024 Q1:

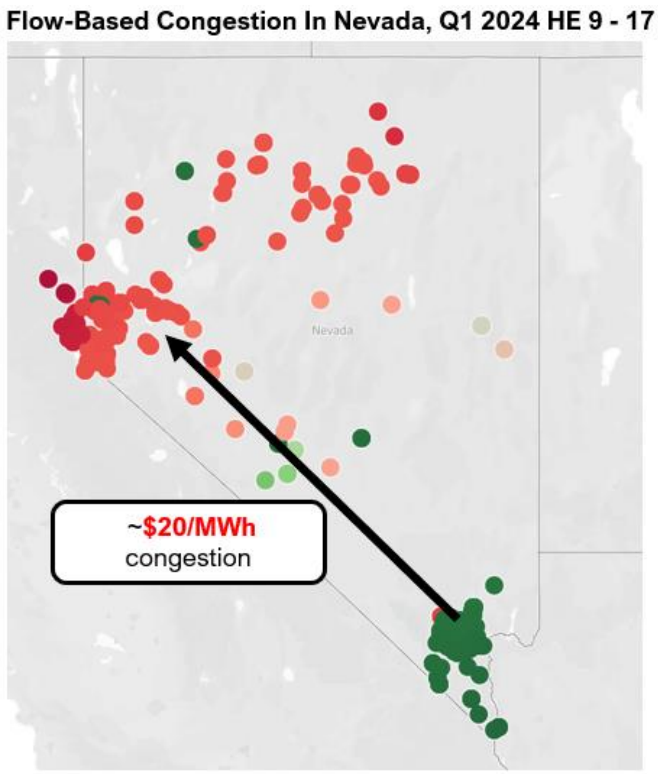
Flow-Based Congestion In PacifiCorp East, Q1 2024 HE 9 - 17



<u>What NV Energy transmission paths would be most affected if it chooses to join under the current EDAM market design?</u>

NV Energy has made large investments to expand North/South transmission connectivity within the state. These investments include the $500 million One Nevada (ON) Line, the Greenlink project, currently estimated to cost $4.5 billion, and an agreement to receive a share of the SWIP line, once it is complete. Each of these transmission investments are being pursued to enable NV Energy, its 704B customers, and other third-party customers, to deliver solar generation from Southern Nevada to loads in Northern Nevada, as well as to export that generation to Idaho and to the broader Northwest region during periods of solar oversupply. These three projects also enable NV Energy (and its 704B customers) to deliver generation from Northern Nevada to serve load in Southern Nevada, and to receive imports from Idaho and the broader Northwest region when it is economic to do so and/or when Southern Nevada is experiencing high demand, particularly in the summer season.

If NV Energy were to join EDAM under the current design, it would be required to pay California ISO congestion charges whenever NV Energy makes deliveries on the multiple major transmission projects it is pursuing within the state of Nevada. Powerex's analysis of data from the Western EIM shows that flow-based congestion charges for deliveries of generation in Southern Nevada to load in Idaho during the solar hours of 2024 Q1 averaged $22.57/MWh, of which nearly all were due to constraints in the California ISO and would go to the California ISO's own customers under the EDAM market design. The chart below shows roughly $20/MWh flow-based congestion price separation occurring entirely within NV Energy's service area during the solar hours in 2024 Q1:

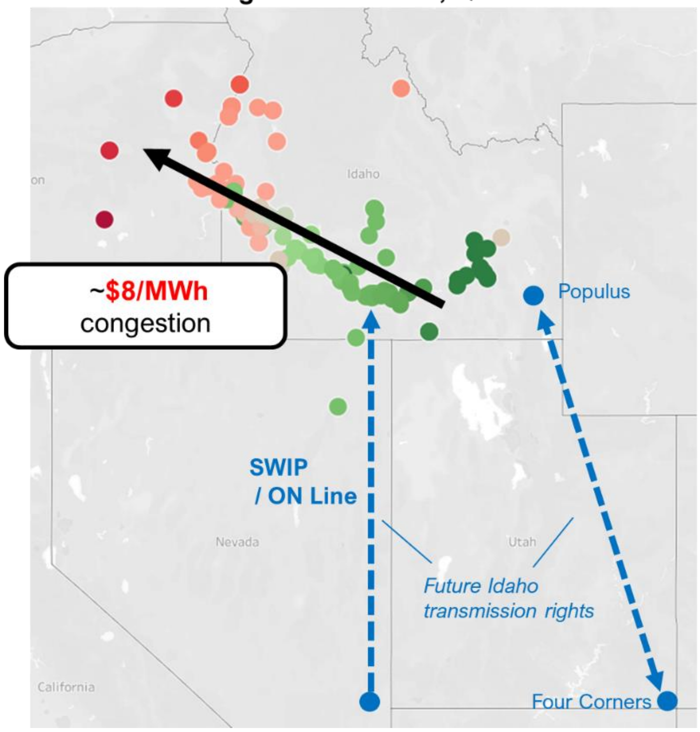


<u>What Idaho Power transmission paths would be most affected if it chooses to join under the current EDAM market design?</u>

Although Idaho Power's transmission system is largely in the Northwest region, price separation nevertheless occurs frequently even within its service territory. This is seen in the chart below, which shows the average Western EIM price separation occurring in Idaho Power's service area during the solar hours in 2024 Q1. In particular, there is flow-based congestion during solar hours for delivering generation in the East and South to serve load in the West and North.

The chart below shows roughly $8/MWh of flow-based congestion price separation occurring entirely within Idaho Power's service area during the solar hours in 2024 Q1:

Flow-Based Congestion In Idaho, Q1 2024 HE 9 - 17



Idaho Power is also pursuing new transmission connectivity beyond its existing service territory. This includes obtaining 200 MW of ownership rights from PacifiCorp on the Four Corners-to-Populus path as part of the Boardman-to-Hemingway arrangements. In addition, Idaho Power is exploring an investment in 500 MW of transmission rights on SWIP and the One Nevada (ON) Line. Both of these new North/South delivery paths can be expected to have significant parallel flows on the California ISO transmission system, exposing deliveries on these new projects to frequent large and volatile charges for congestion on the California ISO system. As a result, **once Idaho Power's investments in new transmission facilities are complete and additional solar generation has been built to utilize these new transmission facilities, Idaho Power (if it joins EDAM under the current design) will be exposed to paying California ISO customers an ongoing, large, and volatile charge whenever Idaho Power delivers energy on these facilities.**

<u>Will customers that use firm transmission service on systems that do not participate in EDAM be exposed to charges for congestion on the California ISO transmission system?</u>

No. EDAM cannot impose congestion charges or other financial settlement on deliveries using transmission service from TSPs that do not participate in EDAM. Transmission systems that remain outside of EDAM will continue to be able to use their systems up to the scheduling limit for the transmission paths they own, and will continue to not incur costs associated with parallel flows on other systems arising from the use of their system.

Would customers that use firm transmission service on systems that participate in Markets+ be exposed to charges for congestion on other transmission systems?

No. Markets+ is designed very differently than EDAM. Like all other day-ahead organized markets, Markets+ uses congestion charges collected by the market operator to provide a direct financial hedge to entities with firm transmission rights. This hedge offsets the day-ahead congestion charges between the source and the sink of the firm rights. In this manner, all deliveries using firm transmission rights of a TSP that participates in Markets+ will be protected from day-ahead congestion charges, including charges related to parallel flows on other transmission systems in Markets+.

What options are available to ensure that the retail ratepayers and third party transmission customers that fund the PacifiCorp, NV Energy or Idaho Power transmission systems continue to receive the value of those systems?

In the near term, PacifiCorp (and other EDAM transmission service providers) could provide a full carve-out from EDAM to its third-party transmission customers, similar to Markets+. This would protect those customers from EDAM charges altogether. ***This would require PacifiCorp's January 16 proposal (which has a comment/protest deadline of February 18) to be withdrawn by PacifiCorp or rejected by FERC.***

While a carve-out could protect unaffiliated third-party customers of EDAM transmission service providers, it appears that protecting the retail ratepayers of utilities that participate in EDAM would be more challenging, as EDAM participants are expected to not use a carve out feature. Protecting their retail ratepayers would therefore require the California ISO to agree to modify the design of EDAM to be consistent with other day-ahead organized markets and with Markets+.

If the California ISO is unwilling to modify the EDAM design, and utilities seek to move forward with participating in EDAM under its current design, state regulatory commissions may ultimately find it inappropriate to allow recovery of the costs for parallel flow congestion on other transmission systems in EDAM.