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DEPARTMENT OF SUSTAINABILITY

Comments

To: Public Service Commission of Utah
From: Salt Lake City Corporation
Christopher Thomas, Sustainability Project Coordinator
Date: October 3, 2025
Re: Initial Comments in Docket No. 25-035-30: Avoided Cost Input Changes Quarterly Compliance Filing

Salt Lake City Corporation (SLC Corp) is the local governing body for Utah's capital city. SLC Corp has established renewable energy and carbon emission reduction targets and is a member of the Utah Renewable Communities, a coalition of 19 communities working in partnership with Rocky Mountain Power (Company) to launch a new clean energy option for electricity customers within the communities. SLC Corp is also a party to a renewable energy service contract with the Company pursuant to which a Schedule 34 clean energy resource (the Elektron Solar Project) has reached commercial operation, and SLC Corp may seek future Schedule 34 resources. As such, SLC Corp's interests are substantially affected by the Company's update to its Schedule 38 avoided cost prices. SLC Corp appreciates the opportunity to provide these comments on the update to Schedule 38 avoided cost prices and challenge some of the Company's methodology. Schedule 38 pricing applies to power purchased from Qualifying Facilities located in the state of Utah with a design capacity larger than 3 Megawatts (MW).

Background

On May 7, 2025, the Company filed its Q1 2025 quarterly update on Schedule 38 pricing, which proposed to dramatically reduce avoided cost prices for various energy sources under Schedule 38. The proposed changes are reflected below:

Technology	2024 Q3 Pricing ($/MWh)*	2025 Q1 Proposed ($/MWh)*	Difference (%)
Thermal	53.81	30.77	-43%
Wind	29.02	17.27	-40%
Solar Tracking	38.42	23.41	-39%

* Dollar values shown are from RMP Workpapers, 25-035-30 Appendix B.1 *15-Year Levelized Prices (Nominal) @6.69% Discount Rate from 2026-2040*

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On May 27, 2025, SLC Corp filed comments challenging as non-routine the methodology used by the Company and requesting that the Commission suspend the Company's proposed Schedule 38 updates and open an investigation to allow additional review of the Company's assumptions and calculations.

On July 17, 2025 the Commission noticed a virtual scheduling conference and subsequently issued an order dated August 1, 2025 creating further process in this docket – namely, an opportunity for comments and reply comments.

On September 30, 2025, PacifiCorp filed its Q2 2025 quarterly compliance filing, this time proposing even larger reductions to indicative avoided cost pricing:

Technology	**2024 Q3 Pricing ($/MWh)**	**2025 Q2 Proposed ($/MWh)****	**Difference (%)**
Thermal	53.81	36.82	-32%
Wind	29.02	5.52	-87%
Solar Tracking	38.42	3.84	-86%

** Dollar values shown are from RMP Workpaper Appendix D.2 reproduced on PDF page 53 of Company's September 30, 2025 filing. *15-Year Levelized Prices (Nominal) @6.38% Discount Rate from 2026-2040*

In a closely related docket (Docket No. 25-035-T03) pertaining to Schedule 37 avoided costs, Western Resource Advocates (WRA) requested that the Commission "should not update avoided cost prices pursuant to the 2025 IRP until parties have had a full opportunity to provide recommendations on the IRP" and, further, that the Commission "should consider changing the timing of future avoided cost updates to give stakeholders an opportunity to review the filed IRP before avoided cost changes take effect," among other recommendations.[1]

[1] Docket No. 25-035-T03, WRA Comments (July 18, 2025) at 2.

Another party to that docket, Renewable Energy Coalition (REC) filed reply comments on September 3, 2025 endorsing these two WRA requests.[2]

In its reply comments also filed on September 3, 2025 in that docket, SLC Corp also endorsed all of WRA's recommendations, stating that "[b]ecause of the unprecedented changes to the Company's 2025 IRP, SLC Corp requests that the Commission make a procedural change that delays updates to the Schedule 37 and 38 avoided cost prices until after full evaluation of the Company's 2025 IRP and leave in place the current Schedule 37 and 38 avoided cost prices and inputs until then."[3] SLC Corp enumerates various determinations the Commission could establish at the time the Company's 2025 IRP is either acknowledged or not acknowledged to update Schedule 37 and 38 avoided cost pricing.

The Division of Public Utilities (Division) proposed approving the Company's Schedule 37 avoided cost updates but also says in its reply comments dated September 3, 2025 that "[a]lternatively, the Commission might leave the Schedule No. 37 pricing at the last approved levels until such time the 2025 IRP inputs used to inform the PLEXOS model are better understood, at which time direct RMP to refile its Schedule No. 37 updates."[4]

Discussion

The Company's 2025 IRP introduced several major changes that should be fully vetted by the Commission and stakeholders before Schedule 37 or Schedule 38 avoided cost prices are updated. Until then, the previous approved Schedule 37 and Schedule 38 avoided cost prices and methodologies commensurate with the Company's 2023 IRP Update should be used.

[2] *See* Docket No. 25-035-T03, Renewable Energy Coalition Comments (Sept. 3, 2025) at 6.
[3] Docket No. 25-035-T03, SLC Corp. Reply Comments (Sept. 3, 2025) at 8-9.
[4] Docket No. 25-035-T03, DPU Reply Comments (Sept. 3, 2025) at 4.

As is clear from the Company's September 30 filing in this docket, the major driver of avoided cost price declines for wind and solar are not due to updating the Official Forward Price Curve (OFPC) but instead result from methodological changes in the 2025 IRP:

		Indicative Solar QF Avoided Cost, $/MWh					
	Proposed Term:	**2025 - 2039**		**2026 - 2040**		**2027 - 2041**	
	2025.Q1 As Filed	$23.65		$23.44		$23.68	
Routine update	OFPC June 2025	$23.98	+$0.33	$23.86	+$0.42	$23.92	+$0.24
Routine update	Corrected Escalation	$25.43	+$1.45	$25.57	+$1.71	$25.91	+$1.99
Non-routine update	*Final 2025 IRP*	*$5.94*	*-$19.49*	*$3.58*	*-$21.99*	*$3.72*	*-$22.19*

Nominal Levelized Payment at 6.38% Discount Rate

		Indicative Wind QF Avoided Cost, $/MWh					
	Proposed Term:	**2025 - 2039**		**2026 - 2040**		**2027 - 2041**	
	2025.Q1 As Filed	$16.21		$17.27		$18.50	
Routine update	OFPC June 2025	$16.66	+$0.45	$17.81	+$0.54	$18.82	+$0.32
Routine update	Corrected Escalation	$15.85	-$0.81	$16.90	-$0.91	$17.80	-$1.02
Non-routine update	*Final 2025 IRP*	*$5.40*	*-$10.45*	*$5.44*	*-$11.46*	*$5.10*	*-$12.70*

Nominal Levelized Payment at 6.38% Discount Rate

The Company's 2025 IRP is currently before the Commission for consideration in Docket No. 25-035-22. Eight comments in that docket recommend that the Commission either not acknowledge the IRP in its entirety or not acknowledge fundamental outputs like preferred portfolio resources. Of the remaining two, one is focused solely on energy efficiency and demand side resources and the other questions whether two major aspects of the 2025 IRP comply with Commission guidelines.

SLC Corp highlights the following concerns with the 2025 Utah IRP and the 2025 Final IRP.

The Company's estimated fixed capital costs for solar and wind are unreasonably low.

These unreasonably low capital cost estimates appear to arise from the Company's reliance on the 2024 edition of the National Renewable Energy Laboratory's Annual Technology Baseline

(2024 NREL ATB) for solar, wind, and battery costs. Even Company witness Dan MacNeil does not appear to believe these NREL-derived costs are reasonable. When presenting on the expected capital costs of wind and solar resources in an IRP public input meeting, regarding the very same cost expectations that support the Company's avoided cost adjustments proposed in this docket, Mr. MacNeil stated as follows: "And I guess, I will say, I don't know that we could deliver on these costs. What's shown on this slide [slide 71] is the expected case. I don't know that we could even deliver on this, you know these are very low, lower than we have seen for batteries and solar and wind in recent inquiries we've had. But this is what NREL says."[5]

Mr. MacNeil went on to explain that the Company's previous practice was to use recent offers as the basis for projecting solar, wind, and battery costs, and that the capital cost assumption would be held flat for five years: "We did in the 23 IRP, we included an expectation that the bids we had been receiving were similar to what the actual market price ought to be or the expected cost was for wind and solar and storage and so there was a, through 2028, a flat number that represented those recent bids we had received. That was a pretty good estimate in my opinion but I know there was a lot of concerns about that and so to forestall any sort of like, question that we picked the number, we are using the NREL numbers, you know, with some adjustments to account for, you know, the financing, and utility rate-making kind of aspects but those are just, you know, little adders, um, around the outside. It's a very different number than we've had in the past as you can see on this figure."[6]

The Company understood its application of 2024 NREL ATB capital cost assumptions in the 2025 IRP resulted in anomalously low estimates and acknowledged that it could not "deliver" on

[5] See Dan MacNeil discussion of slide 78 from PacifiCorp's September 25, 2025 2025 Public Integrated Resource Plan (IRP) meeting: 2025 IRP Public Input Meeting 7 - September 25, Part 2 - YouTube beginning at 2:55:45.
[6] Ibid at 2:56:19.

these “very low” costs. State and Federal policy developments during this timeframe argued against assuming near-term cost declines.

As has been discussed in other dockets, the Company has acknowledged an error in the manner in which it utilized the NREL ATB capital costs to inform supply-side resource costs for wind, solar, and storage resources.[7] Specifically, the supply-side resource table sought to incorporate a forecast of CAPEX costs for wind and solar resources from the NREL ATB. While the NREL ATB reflected CAPEX cost declines starting with the first year that the resource could be built, the Company erroneously began these CAPEX cost declines starting in 2025. This error artificially reduced the cost of solar and storage resources in the supply-side resource table. This modeling error may have affected the selection of resources in the Preferred Portfolio.

The Company’s use of “jurisdictional share portfolios” is non-routine and should be rejected.

Also new for the 2025 IRP, the Company assigned shares of integrated system-wide preferred portfolio resources to individual jurisdictions to meet jurisdictional requirements. In other words, the Company uses the jurisdictional share process to take resources that would be cost-effective for Utah customers and then “assign” those resources to Oregon and Washington to satisfy those states’ policies regarding renewable resources.

For example, although the UIWC full jurisdictional portfolio selects 153 MW of solar as being cost-effective for Utah customers in 2028, the Company’s jurisdictional assignments fully allocate these 153 MW of solar to Oregon and Washington, as illustrated in the following excerpt from Table 9.11 from the 2025 IRP:[8]

[7] *See, e.g.*, Docket No. 25-035-22, UAE Initial Comments (Sept. 25, 2025) at 13-15 (discussing Company modeling error in utilizing NREL ATB capital costs in setting supply-side resource costs).
[8] 2025 IRP (Vol. I), Table 9.11 (p. 244).

Resource	2025	2026	2027	2028
Renewable - Utility Solar	-	-	-	**222**
OR	-	-	-	167
WA	-	-	-	56
UIWC	-	-	-	-

To put it another way, every full jurisdictional portfolio showed cost-effective solar additions in 2028 (153 MW for Utah, Idaho, Wyoming, and California, 201 MW for Washington, and 122 MW for Oregon), but apparently because Oregon and Washington have created Renewable Portfolio Standards (RPS) requirements and have imposed on utilities the obligation to demonstrate compliance with those standards, the "integrated" 2025 IRP preferred portfolio allocates to Oregon and Washington certain resources that would otherwise be allocated to all jurisdictions, including Utah.

This "jurisdictional share" portfolio approach prejudices the Company's Utah customers because it deprives Utah customers of the opportunity to acquire cost-effective resources. This is because, also new in the 2025 IRP, the Company has decided that instead of hosting a system-wide all-source solicitation as it has previously done, it will "initiate with individual jurisdictions the process to issue as appropriate by individual jurisdiction need, one or more independent Request for Proposals (RFP) to procure resources aligned with the 2025 IRP preferred portfolio that can achieve commercial operations by the end of December 2029."[9]

There is only one portfolio in the 2025 IRP that shows the cost-effective resource acquisition strategy for the Company's Utah customers that is free from the influence of Oregon and Washington policies, and that one is the UIWC Full Jurisdictional Portfolio depicted in Table 9.7 of the 2025 IRP,[10] which is reproduced below (with the earliest solar and wind resource additions highlighted):

[9] 2025 IRP (Vol. I), p. 15 (emphasis added).
[10] *See* 2025 IRP (Vol. I), Table 9.7 (p. 225).

Table 9.7 – Utah, Idaho, Wyoming, California (UIWC) Full Jurisdictional Portfolio

Summary Portfolio Capacity by Resource Type and Year, Installed MW													
	Installed Capacity, MW												
Resource	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037
Expansion Options													
Gas - CCCT	-	-	-	-	-	-	-	-	-	-	-	-	-
Gas - Peaking	-	-	-	-	-	-	-	-	-	-	-	-	-
Nuclear	-	-	-	-	-	-	-	500	-	-	-	-	-
Renewable Peaking	-	-	-	-	-	-	-	-	-	-	-	-	-
DSM - Energy Efficiency	92	89	164	170	182	196	270	236	247	251	261	286	312
DSM - Demand Response	18	2	-	2	7	112	99	-	-	-	5	39	115
Renewable - Wind	-	-	-	-	306	684	344	-	-	-	-	-	-
Renewable - Small Scale Wind	-	-	-	-	-	-	-	-	-	-	-	-	-
Renewable - Utility Solar	-	-	-	153	12	79	668	-	31	123	133	3	-
Renewable - Small Scale Solar	-	-	-	-	-	-	-	-	-	-	-	-	-
Renewable - Geothermal	-	-	-	-	-	-	-	-	-	-	-	-	-
Renewable - Battery, < 8 hour	-	-	-	193	71	224	-	-	-	-	85	171	4
Renewable - Battery, 8-23 hour	-	-	-	-	-	-	-	-	-	-	-	-	-
Renewable - Battery, 24+ hour	-	-	-	-	-	-	-	-	-	-	-	-	-
Other Renewable	-	-	-	-	-	-	-	-	-	-	-	-	-
Storage - Other	-	-	-	-	-	-	-	-	-	-	-	-	-

About the full jurisdictional portfolios, the Company writes: "Each jurisdiction's resource selections begin with a view of the entire system as optimized under that jurisdiction's particular constraints. These idealized views of the system allow each jurisdiction's preferred resource selections to be identified. These portfolios are referred to as the 'full jurisdictional portfolios' and show the selections prior to integration."[11] Therefore, from the perspective of Utah's jurisdictional constraints, 153 MW of solar are selected as cost-effective in 2028 and 306 MW of wind are selected as cost-effective in 2029.

In its initial comments on the 2025 IRP, Utah Clean Energy (UCE) says that the "jurisdictional allocation modeling methodology in no way represents a portfolio that is best for the system, and insufficiently determines the least-cost, least-risk portfolio."[12]

The Utah Association of Energy Users (UAE) says about PacifiCorp's jurisdictional allocation method that "[r]esources that otherwise would be acquired for the whole system are 'assigned' to Oregon and Washington to satisfy the policy preferences in those states. The end result is

[11] 2025 IRP (Vol. I), page 222.
[12] Docket No. 25-035-22, Utah Clean Energy Comments (Sept. 26, 2025) at 3.

that PacifiCorp's effort to account for the state policy preferences in Oregon and Washington takes resource decision-making authority away from Utah for resources that are needed to serve the whole system."[13]

The Company's 2025 IRP preferred portfolio selection is based on an "end effects" analysis with a flawed methodology.

The Commission's IRP guidelines[14] require that the Company's IRPs include a 20-year planning horizon. In response to a requirement imposed by Washington State, the 2025 IRP is based on a 21-year planning horizon rather than the traditional 20-year horizon.[15]

In the 2025 IRP, the Company selected as the preferred portfolio the **Integrated Base MN portfolio**, which is the portfolio expected to perform the best under the MN (medium gas, no CO_2) price policy scenario. Surprisingly, the Integrated Base MN portfolio ranks only fourth in the ST model run in this MN scenario and second when adjusted for risk.[16] The **Integrated Base HH portfolio** performs better both in the MN model run and when adjusted for risk than the portfolio selected by the Company. In fact, the Integrated Base HH portfolio costs $106 million less on a risk adjusted basis than the Company's chosen portfolio under MN (medium gas, no CO_2) price policy assumptions.[17] The Integrated Base HH portfolio also performs better than the Company's chosen portfolio in the scenario that assumes LN (low gas, no CO_2) price policy

[13] Docket No. 25-035-22, UAE Initial Comments (Sept. 26, 2025) at 11.
[14] *In the Matter of Analysis of an Integrated Resource Plan for PacifiCorp*, Docket No. 90-2035-01, Report and Order on Standards and Guidelines issued June 18, 1992 ("IRP Guidelines Order"). A copy of the IRP Guidelines Order is attached hereto as Exhibit 1.
[15] *See* 2025 IRP Vol. 1 at 181 n.1.
[16] *See id*. at 260, Table 9.34.
[17] *See id.* at 260, Table 9.34 (showing that using Medium Gas/Zero CO2 price policy assumptions, the Risk Adjusted Stochastic PVRR for the Integrated Base HH portfolio is $27,512m, whereas the Risk Adjusted Stochastic PVRR for the Integrated Base MN portfolio is $27,618m).

assumptions (by $236 million)[18] and in the scenario with HH (high gas, high CO_2) price policy assumptions (by *$3 Billion*)[19] over the 21-year planning horizon. During the 21-year planning period in the ST model run, the Integrated Base MN portfolio selected by the Company ranked 4th in the MN price policy-scenario, 5th in the LN price-policy scenario, and 8th in the HH price-policy scenario.[20] By contrast, the Integrated Base HH portfolio ranked 2nd in the MN scenario, 3rd in the LN scenario, and 1st in the HH scenario in those same model runs. That is, the Integrated Base HH portfolio considerably outperforms the Company's chosen portfolio in every price policy scenario over the 21-year planning horizon.

The only scenario in which the Company's chosen Integrated Base MN portfolio performs better than the Integrated Base HH portfolio is when the Company considers "end effects" in the MN price policy scenario. In that "end effects" scenario, the Integrated Base MN portfolio outperforms the Integrated Base HH portfolio by $51 million. The Company's selection of the Integrated Base MN portfolio despite its somewhat mediocre performance during the planning period is based entirely on its performance when "end effects" are considered. As such, the "end effects" modeling deserves more than a little scrutiny. As an initial matter, the Company apparently conducted its "end effects" modeling *only* in the MN scenario, and not in either the HH or LN scenarios. In addition, the "end effects" scenario does not actually consider what happens *after* the conclusion of the planning period. Instead, it assumes that the final year of the planning period—the 21st year in the 2025 IRP's planning period—is repeated for five additional years under the medium gas/Zero CO2 assumptions.[21]

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[18] *Id*. at 260, Table 9.35 (showing that, using Low Gas/Zero CO2 price policy assumptions, the PVRR for the **Integrated Base HH** portfolio is $24,990m, whereas the PVRR for the Integrated Base MN portfolio is $25,226).
[19] *See id.* at 260, Table 9.35 (showing that using Low Gas/Zero CO2 price policy assumptions, the PVRR for the Integrated Base HH portfolio is $31,498m, whereas the Risk Adjusted Stochastic PVRR for the Integrated Base MN portfolio is $34,498m).
[20] *See id*. at 260-261, Tables 9.34-9.36.
[21] *See* Docket No. 25-035-22, RMP response to WRA DR 3.1. A copy of RMP's response to WRA's third set of data request in the 2025 IRP docket is attached hereto as Exhibit 2.

It may well be appropriate to consider the revenue requirement effects that occur after the planning horizon when selecting between portfolios that otherwise perform comparably. SLC Corp is concerned, however, with the weight given to the "end effects" considered in the 2025 IRP, as the Company seems to place greater importance on the "end effects" than the results in the 21-year planning horizon.

SLC Corp is also concerned about the methodology utilized in the Company's "end effects" modeling. As noted above, the Company's "end effects" modeling simply assumes that the revenue requirement for the final year of the 21-year planning period is repeated for five additional years. This methodology does not measure the effects *after* the planning horizon and places undue weight on a single year's results. Any given portfolio considered in the 2025 IRP could require large investments (or yield large revenue requirement benefits) in the years immediately after the planning period. The "end effects" modeling does not account for those potential outcomes. Given the limitations of the "end effects" modeling methodology, the Commission should heavily scrutinize the Company's emphasis on its results.

The Company's decision to select the Integrated Base MN portfolio based on the "end effects" modeling results appears to violate the Commission's IRP guidelines in two ways:

- the calculations that determined the Company's preferred portfolio selection did not adhere to a "20-year planning horizon," as required,[22] and
- by only calculating "end effects" for one price policy scenario (medium gas/Zero CO2) and not the others (low gas/Zero CO2 and high gas/High CO2), the portfolios are not evaluated on a "consistent and comparable basis," as required.[23]

[22] IRP Guidelines Order at 35 (Standard 4(d)).
[23] *Id*. at 33 (Standard 1 ("Definition: Integrated resource planning is a utility planning process which evaluates all known resources on a consistent and comparable basis, in order to meet current and future customer electric energy services needs at the lowest total cost to the utility and its customers, and in a manner consistent with the long-run public interest.")).

Both WRA and UAE raise similar concerns in their initial comments about the Company's 2025 IRP in Docket No. 25-035-22.

For its 2025 Final IRP, PacifiCorp appears to have abandoned least-cost system-wide resource planning.

In its initial comments on the Company's 2025 IRP, WRA writes:

> In integrating the Full Jurisdictional Portfolios, PacifiCorp limited the location of proxy resources, resulting in a bifurcated plan. Proxy resources located on the west-side of the PacifiCorp system were included only if they had been selected in either Washington's or Oregon's Full Jurisdictional simulations, and proxy resources located on the east-side were included only if they had been selected in UIWC's Full Jurisdictional simulations. So, east-side resources identified as optimally serving the system under Oregon or Washington compliance constraints (i.e. environmental regulations plus resource adequacy) were excluded; similarly, west-side resources identified as optimally serving the system under the UIWC constraint (i.e. resource adequacy only) were excluded from the Integrated Portfolios.

As WRA notes, a problem with this approach is that, "single system planning and operation, and cost allocation consistent with single system planning and operation, remain the standard in Utah against which all deviations must be evaluated. This requires the development of a system plan against which the costs of planning separately for the west and east sides can be compared. The 2025 IRP does not provide this comparison."[24]

[24] Docket No. 25-035-22, WRA Initial Comments (Sept. 25, 2025) at 22.

In the absence of a cost-optimized system-wide plan, it is impossible to tell if the novel integration approach used by PacifiCorp is actually the least-cost approach for its Utah customers.

UCE raises a similar concern in its initial comments on the 2025 IRP when it writes:

> The Company frequently notes that the IRP process is not a cost allocation process; it is a capacity expansion model designed for system planning. However, the 2025 IRP process modeled some of the states separately and then rolled them up into a system-wide portfolio. This approach is counter to robust modeling of the system as a whole to first identify a preferred least-cost, least risk portfolio before evaluating and modelling changes necessary to comply with state specific requirements. The jurisdictional allocation modeling methodology in no way represents a portfolio that is best for the system, and insufficiently determines the least-cost, least-risk portfolio.[25]

Because the Company did not produce a fully cost-optimized portfolio for the entire system against which to compare the results of its bifurcated jurisdictional approach, the portfolio identified by the Company as its 2025 IRP for use in avoided cost modeling may not comply with Commission IRP guidelines.

[25] Docket No. 25-035-22, Utah Clean Energy Comments (Sept. 26, 2025) at 3.

The Final 2025 IRP makes unreasonably low load growth forecasts and may not comply with the Commission's IRP guidelines.

In its initial comments on the Company's IRP, UCE notes that between the 2025 Utah IRP produced on December 31, 2024 and the 2025 Final IRP filed on March 31, 2025, the Company more than halved its forecasted load growth rate for Utah, from 4.08% to 1.75%.

About this sudden and dramatic change, UCE writes:

> The load forecast is one of the most fundamental modeling inputs in the IRP (as discussed above), affecting resource procurement, transmission buildout, and every other aspect of the IRP. There is no compelling reason why the load forecast should have decreased by more than half between the Draft IRP and the Final IRP. As noted above, large loads like data centers should only account for a fraction of the projected load growth, but there was no opportunity to meaningfully engage with the Company about these significant changes in their load forecast.

Indeed, between 2023 and 2024, Berkshire Hathaway Energy reported a 4.1% increase in PacifiCorp's Utah electricity sales:

	2024		2023	
Utah	27,138	46 %	26,062	46 %
Oregon	13,991	24	13,949	25
Wyoming	8,759	15	8,579	15
Washington	4,112	7	3,850	7
Idaho	3,728	7	3,496	6
California	747	1	760	1
Total	58,475	100 %	56,696	100 %

PacifiCorp's actual 2024 Utah load growth is extremely similar to the Utah load growth projection used in the Company's 2025 Utah IRP and presumably does not reflect any new large-load data centers. For this reason, it is reasonable to suspect that even absent new large-load data centers, the Company's Utah loads could grow at closer to 4% annually. If that is the case, then the Company's 2025 Final IRP will significantly under-build resources for its Utah customers.

Anecdotally, SLC Corp has heard from several businesses who are not large-load data centers that the Company has refused, curtailed, or delayed their load requests for lack of energy resources. If continued, the lack of new energy resources could severely constrain Utah's economic growth.

Requests

Because of the unprecedented changes to Company's 2025 IRP, SLC Corp requests that the Commission make a procedural change that delays updates to the Schedule 37 and 38 avoided cost prices until after full evaluation of the Company's 2025 IRP and leave in place the current Schedule 37 and 38 avoided cost prices and inputs until then.

SLC Corp further requests that, after the Commission issues its order in Docket No. 25-035-22 regarding the 2025 IRP, then—in this docket and the separate docket to address Schedule 37—the Commission issue specific findings related to the choice of portfolio and cost assumptions used as inputs in the avoided cost methodology, including:

- whether the portfolio used as an input for avoided cost price calculations should be based on the IRP planning period, as required in the Commission's guidelines;
- whether the portfolio used as an input for avoided cost price calculations should include resources that have been modeled as "zero cost" resources, which appears to be

prohibited by the Commission's requirement that resources be evaluated on a "comparable and consistent basis";

- whether the cost for resources included in the portfolio should be "deliverable," in other words, set at a level that the Company could reasonably expect to acquire such resources, and whether these costs should be assumed to de-escalate in the first five years;
- if the Company bases its cost assumptions on a third-party resource like the NREL ATB, whether the publication of new cost assumptions should be automatically incorporated as routine updates in avoided cost updates;
- whether the portfolio used as an input for avoided cost price calculations should reflect cost-effective resource selections for Utah customers, free from the influence of other states' energy policies and requirements for RECs;
- whether the IRP models Renewable Energy Certificates (RECs) as having financial value, and if not, ordering that RECs should be owned by QFs to maintain customer indifference; and
- whether IRP assumptions match current Federal policy with regard to energy-related tax credits and, if not, whether the avoided cost calculation should assume that a future deferrable proxy resource should model energy tax credits as lost customer revenue, based on when the proxy resource is deferred.

At a time of unprecedented electrical demand growth, artificially low avoided cost prices could jeopardize the State of Utah's economic growth opportunities for the foreseeable future.
At a time of unprecedented electrical demand growth, artificially low avoided cost prices could jeopardize the State of Utah's economic growth opportunities for the foreseeable future.

DATED October 3, 2025

Respectfully submitted,

/s/ Christopher Thomas

Christopher Thomas

Sustainability Project Coordinator

CERTIFICATE OF SERVICE
Docket No. 25-035-30

I hereby certify that a true and correct copy of the foregoing was served by email this 3rd day of October 2025, on the following:

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