UTAH CLEAN ENERGY

Date: October 10, 2023

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Subject: Docket No. 23-035-10 (2023 Integrated Resource Plan): Utah Clean Energy Question for October 24, 2023 Technical Conference

Impact of RFP Suspension:

Utah Clean Energy appreciates the opportunity to participate in the technical conference and obtain answers to outstanding questions about the 2023 IRP. Our first question is how the recent announcement of the suspension of the 2022 All Source RFP affects the 2023 IRP Action Plan, and therefore the entire 2023 IRP. We note that in our stakeholder feedback form regarding the March 31, 2023 IRP we identified several deficiencies in the Action Plan section on "Procurement Delays" and suggested that PacifiCorp identify options and contingencies to mitigate impacts from procurement delays. Unfortunately, that was one of many comments that PacifiCorp failed to provide any response to, and now PacifiCorp is facing a very serious Procurement Delay situation. We have many questions, including:

- How does PacifiCorp plan to acquire new resources in the next 2-4 years that were expected to achieve commercial operation by December 31, 2027 without the 2022 AS RFP? These include ~4000-6000 MW of solar, ~2300 MW of wind, and ~4000 MW of storage.
- If the Action Plan is compromised, are any of the 2023 IRP modeling scenarios still valid?
- How will the suspension impact the interconnection queue and the acquisition of resources planned in the 2023 IRP?
- How will the suspension affect operations and plans for reducing dispatch and planned retirement dates for the existing thermal fleet?
- How will the suspension affect the planned 2024 AS RFP?
- How does PacifiCorp plan to meet future peak load and ensure reliability without the additional capacity from new resources in the 2022 AS RFP?

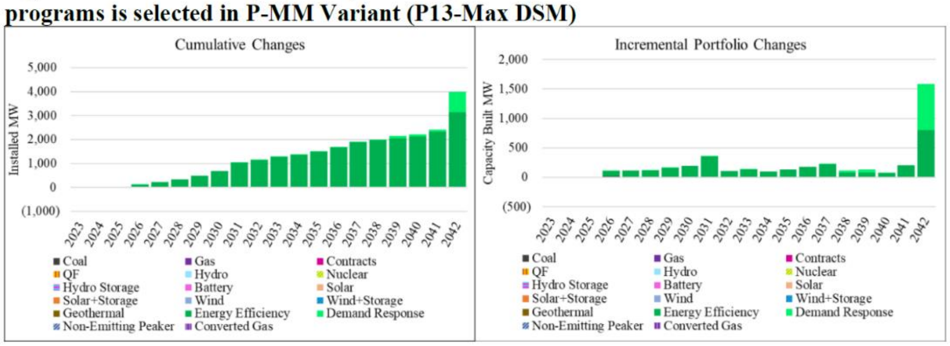
Community Renewable Energy Act

In the 2021 IRP Action Plan Status Update action item 2a (pg 357), PacifiCorp anticipated filing for approval of the Community Renewable Energy Act program with the Utah PSC in 2022, with an associated RFP to procure resources for the program. In the status update in the 2023 IRP, PacifiCorp anticipated filing for approval of the program in 2023, yet to date it has not done so. Given the suspension of the 2022 AS RFP and associated procurement delays discussed above, minimizing delays to the Community Renewable Energy Act program is even more important. ***What is being done to get the Community Renewable Energy Act program back on track?***

Demand Side Management (DSM)

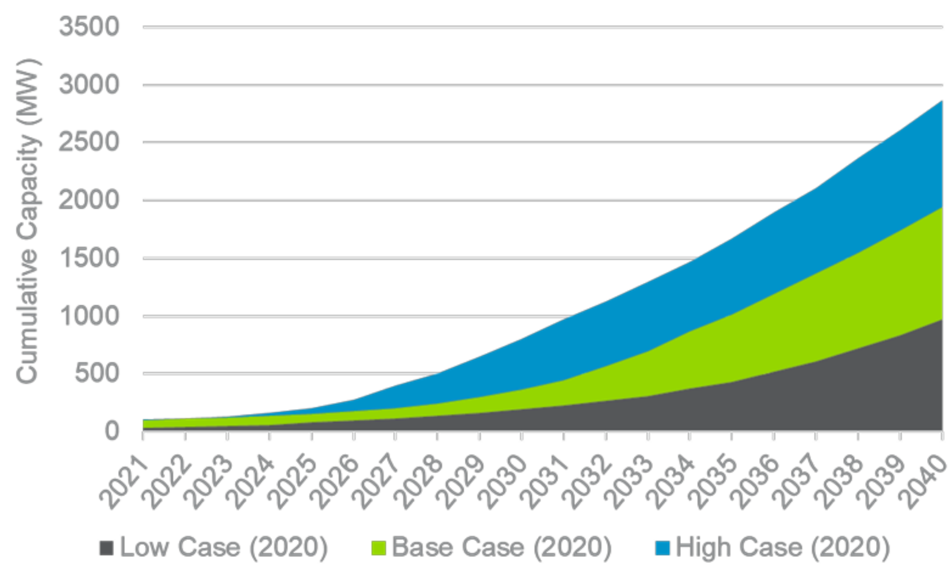
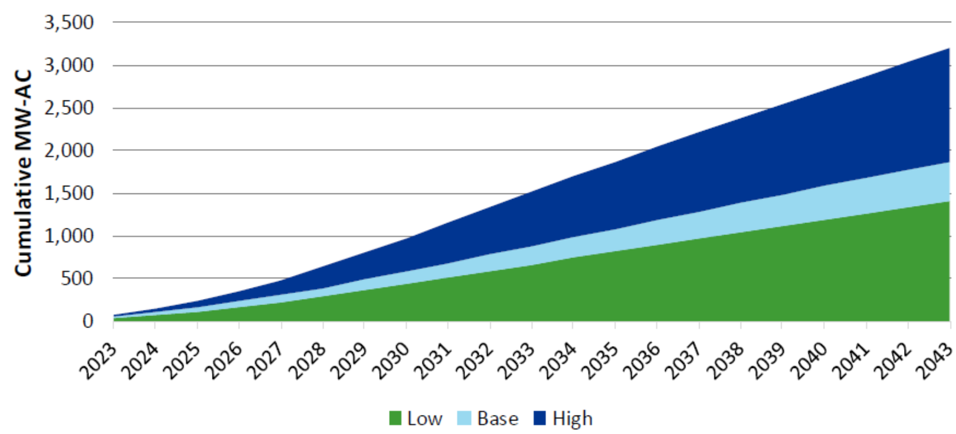
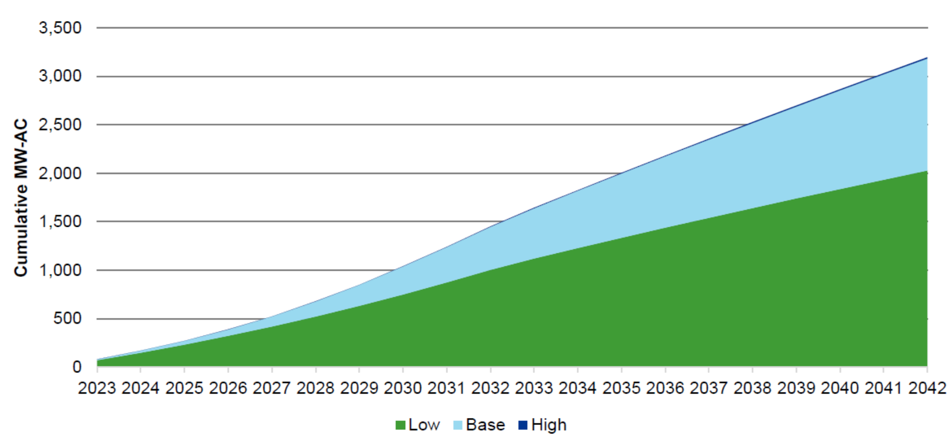
From our March 31 comments on the 2023 IRP, PacifiCorp did not address one of our questions about the P13-Max DSM scenario. In this scenario (figure pasted below), throughout the model run there is very little “Demand Response” (light green) until the very last year in 2042 when approximately 700-800 MW is added in a single year. For “Energy Efficiency” (dark green) there is what appears to be 100-300 MW added each year until 2042 where 700-800 MW is added in a single year, more than doubling the amount added in any prior year. What is driving the massive incremental increase in Energy Efficiency and Demand Response in the year 2042? If it is possible to add ~1600 MW of Energy Efficiency and Demand Response in 2042, why do no other years have incremental increases greater than ~300 MW? Is this a modeling error or is PacifiCorp underestimating the maximum level of DSM throughout the modeling horizon?

Figure 9.24 – Increase/(Decrease) in Proxy Resources when the maximum level of DSM programs is selected in P-MM Variant (P13-Max DSM)



Private Generation (PG):

For the 2023 IRP, PacifiCorp commissioned DNV to produce a Private Generation Forecast that was first discussed in the July 14-15, 2022 Public Input Meeting (PIM) and then the final version of the Private Generation report was released on Feb 2, 2023 and included as Appendix L in the 2023 IRP. There were substantial revisions to the DNV Forecast between the July 2022 PIM and the final version of the report, however since the final version was released only two months before the 2023 IRP draft was released, there was no opportunity for stakeholder input regarding the substantive changes between the PIM and the final version of the report. We have identified two major issues in the final DNV Private Generation report that we describe below. For context, first we include figures showing how Private Generation estimates have changed between the 2021 IRP (conducted by Navigant), the July 2022 PIM, and the final Feb 2023 report:

Navigant Private Generation Assessment (in the 2021 IRP) In 2040 the market penetration is: Low: ~1000 MW Base: ~1900 MW High: ~2900 MW	**Figure 2 Cumulative Market Penetration Results (MW AC), 2021 – 2040** 
DNV Private Generation Forecast (July 14-15, 2022 Public Input Meeting) In 2040 the market penetration is: Low: ~1100 MW Base: ~1600 MW High: ~2600 MW	Cumulative New Capacity Installations, All States 
DNV Private Generation Forecast (Feb 2, 2023, included as Appendix L in the 2023 IRP) In 2040 the market penetration is: Low: ~1700 MW Base: ~2700 MW **High: ~2700 MW**	**Figure 1-3 Cumulative New Capacity Installed by Scenario (MW-AC), 2023-2042** 

The first issue with the final DNV report is that the "Base" and "High" private generation estimates are virtually identical (the high scenario is only 0.5% higher than the base case in 2042). Between the July 2022 PIM and the final version, the "Base" case increases substantially, most likely because of passage of the Inflation Reduction Act (IRA) in 2022, since provisions in the IRA provide many opportunities to expand private generation in the residential, commercial and industrial sectors. While many of the IRA provisions were known by Feb 2023 when the final report was issued, many more programs were still being finalized by federal agencies, making it challenging to provide a quantitative estimate of the full impacts of the IRA on private generation. This kind of uncertainty is exactly why the "Base" and "High" private generation scenarios are needed, so that it is possible to provide bounds on an uncertain policy environment. However, despite a large increase in the "Base" case scenario, inexplicably, DNV failed to examine a true "High" case scenario. Based on prior versions of the private generation studies, a reasonable "High" case should have had ~30-50% higher capacity than the "Base" case, or around ~4000 MW.

The second issue with the final DNV report is the assumption that net billing policies will remain unchanged throughout the study horizon. The 2021 Navigant Private Generation Assessment noted:

> *"State incentives drive the local market and are an important aspect promoting PG market penetration. Currently, all states evaluated have full retail rate net energy metering (NEM) in place for all customer classes considered in this analysis. The study assumes that NEM policy remains constant, although future uncertainty exists surrounding NEM policy."*

Between the Navigant and DNV study, however, the modeling assumptions were changed and the final version of the DNV study assumed that current net billing policies would remain unchanged:

> *"DNV developed a behind-the-meter net economic perspective that includes, as costs, the acquisition and installation costs for each technology less the impact of available incentives and, as benefits, the customer's economic benefits of ownership such as energy and demand savings and export credits.* ***For this study we assumed that the current net metering or net billing policies and tariff structures in each state continued throughout the study horizon.*** *This resulted in the model incorporating benefits associated with net metering in Oregon, Washington, and Wyoming and net billing in Utah and California."*

Changes to net billing policies would significantly change the economic factors of private generation and would therefore be expected to have important impacts on installed capacity that are critical for PacifiCorp and interested stakeholders to fully understand. Future scenarios examining installed capacity of private generation must examine how changes in net billing policies could affect private generation installed capacity.

We reiterate our request from earlier this year (from our Stakeholder Feedback Form to the March 31, 2023 IRP) that PacifiCorp run a meaningful high Private Generation scenario S-05 that is at least 30-50% higher than the 2023 base case to adequately assess the impact of increased uptake of private generation. We request an update on the status of this sensitivity

study in the Technical Conference and look forward to seeing the revision included in the 2023 IRP Update.

The 2021 Naviant Private Generation Assessment can be found here:

https://www.pacificorp.com/content/dam/pcorp/documents/en/pacificorp/energy/integrated-resource-plan/2021-irp/2021-irp-support-and-studies/PacifiCorp_2021_IRP_PG_Resource_Assessment.pdf

The July 14-15, 2022 PIM slides can be found here:

https://www.pacificorp.com/content/dam/pcorp/documents/en/pacificorp/energy/integrated-resource-plan/2023-irp/PacifiCorp_2023_IRP_PIM_July14-15_2022.pdf