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Division of Public Utilities

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Comments on PacifiCorp's 2019 IRP

To: Public Service Commission of Utah

From: Utah Division of Public Utilities

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Re: Docket No. 19-035-02, PacifiCorp's 2019 Integrated Resource Plan

Date: February 4, 2020

Recommendation (Acknowledge)

The Division of Public Utilities (Division) recommends that the Public Service Commission (Commission) acknowledge that PacifiCorp's 2019 Integrated Resource Plan (IRP) largely adheres to the Commission's Standards and Guidelines.[1] Taken as a whole the IRP should be acknowledged as generally being in compliance with the Commission's Standards and Guidelines. The Division recommends that the Commission take no action on PacifiCorp's 2019 IRP Action Plan, as the prudence review of specific items will take place in other dockets.

[1] Docket No. 90-2035-01, Report and Order on Standards and Guidelines, June 18, 1992 (Standards and Guidelines).

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1. Key Findings and Recommendations

The Division presents to the Commission our key findings and recommendations below. Some of the recommendations refer to "Standards and Guidelines" that were issued by the Commission in a 1992 order, and that PacifiCorp (the Company) is to follow in preparing IRPs. The Standards and Guidelines are reproduced in Appendix A of these Comments.

- The Company's 2019 IRP does not fully adhere to Guideline 3, which mandates that IRPs be developed in consultation with the Commission, the Division, the Office of Consumer Services, and other interested parties. The Company's inability to distribute meeting materials until hours before the meetings violated this Guideline, which states in part: "PacifiCorp will provide ample opportunity for public input and information exchange…"[2] The Company's tardiness compromised the ability of stakeholders to examine and question the materials at stakeholder meetings, thus impairing the public input process and transparency goal of the IRP. The Company should provide meeting materials at a minimum of three business days in advance of public meetings or phone calls, in order for the parties to have a meaningful chance to review the materials.

- The Division sees this IRP with its new vision and goal to reduce greenhouse gas (GHG) emissions as possibly departing from the fundamental objective of least-cost, least-risk planning. In the 2017 IRP the Company pursued economic opportunity investments in lieu of least-cost, least-risk planning principles, and then tried to justify them first as an economic opportunity, and later as a least-cost, least-risk resource. In this 2019 IRP, the focus has been on the Company's coal studies it was required to complete per a requirement from the Oregon Public Utility Commission. The results of the coal studies fed into the development of portfolio cases, which were run through extensive modeling scenarios. The end result is that PacifiCorp will be closing many coal plants before originally planned. To this end, it appears the focus of the IRP may be on reducing GHG emissions, rather than finding the least-cost, least-risk portfolio. The Commission stated in its 2017 IRP Report and Order that: "Least-cost least-risk planning is not a quaint

[2] *Id.* at 42.

concept of the past; it remains the **fundamental** objective of the IRP process."[3] The Division interprets this to mean least-cost, least-risk planning takes precedence over finding resource portfolio mixes that contain low or no carbon emissions. It may be that the least-cost, least-risk scenario is also a low GHG scenario. However, the Company should not pursue low emissions as its fundamental objective.

- The Division is not persuaded that the IRP model results reflect the "true" least-cost, least-risk portfolio for several reasons, including:
    - The fact that not all transmission options were available to be endogenously selected by the model;
    - The lack of clarity around the amount of firm front-office transactions (FOTs) that will be available in future years;
    - The possibility that recent changes in the production tax credit (PTC) deadlines may affect the analysis;
    - Uncertainty regarding the capacity and location of the winners of the upcoming all-source request for proposal bids; and
    - Questions regarding the Company's tendency to overestimate its future load.

  However, given the load forecast and model inputs actually used by the Company, and the information and resources it had at time of modeling, the Division acknowledges that the Company in general followed an appropriate least-cost, least-risk methodology.

- The Division has concerns about the timeline of some of the projects proposed in the 2019 IRP Action Plan. A recent federal appropriations package extended PTCs for another year.[4] The one-year PTC extension could change the economics of some of the modeled portfolios. For some projects that the Company was previously rushing to get built before the PTCs expired, the new least-cost path and timeline could change.

[3] Docket No. 17-035-16, Report and Order on PacifiCorp's 2017 IRP, March 2, 2018, p. 18 (emphasis added).
[4] H.R. 1865 (Further Consolidated Appropriations Act). See, e.g., Trump signs legislation to boost DOE funding, extend wind power credit, S&P Global Market Intelligence, Dec. 23, 2019, available at: https://www.spglobal.com/marketintelligence/en/news-insights/trending/oqglr5awktaxpnbn_7xohq2
H.R. 1865 restored the PTC to 60% for facilities that enter service in 2020, but it is not clear whether this affects any Company projects.

- Before a Certificate of Public Convenience and Necessity (CPCN) for Gateway South is issued (Action Item 3a), or other approvals, the Division recommends further analysis regarding how the new PTC deadlines and percentages affect the preferred portfolio and alternatives.

- The Division is still reviewing the Company's treatment of demand-side management resources, and reserves the right to comment on this issue in its reply comments, after reviewing comments from other parties (Action Item 4a).

- The Division recommends that separate electric vehicle (EV) forecasts, with sensitivity scenarios, be included in the load forecast used in the 2021 IRP.

- The Division recommends the Company address the questions at the end of Section 11 regarding its transmission projects in its reply comments.

- The Division recommends keeping a close eye on regional resources in the 2023-2027 period, and the projected jump in the 2019 IRP projections in summer FOTs in 2028. Action may be required in the next IRP if these trends continue; however, no action is required at this time.

- The Division requests that the Company address the trend in the observed forecast overestimation.

- The Division requests that the Company in future IRP filings provide graphs and analysis comparing forecasts to actual results, including system load and natural gas prices, as described in Section 6 below. In particular, the Division requests that the Company in future IRPs provide graphs comparing past system load forecasts to actual load, and past Henry Hub forecast prices with actual Henry Hub prices, as described in Section 6 below.

- The Division recommends the Commission acknowledge that the Company's 2019 IRP adheres to the Commission's Standards and Guidelines as a whole, despite some particular deficiencies.

- With respect to the Company's 2019 IRP Action Plan, the Division recommends that the Commission take notice of and recognize the list of action items that need to be completed in the first two to four-year period to bring to fruition the 2019 preferred portfolio.

2. Docket Background

This docket was opened on January 28, 2019, when PacifiCorp (the Company) filed a request for an extension of its 2019 IRP filing deadline, from April 1, 2019 to August 1, 2019. The Company identified potential reliability issues that had to be resolved before the Company's coal studies could be completed. The Commission approved the Company's January 28, 2019 request for extension on March 12, 2019. Subsequently, on July 16, 2019, the Company filed with the Commission another request for an extension of its IRP filing deadline from the previously revised date of August 1, 2019 to no later than October 18, 2019. The Company identified problems with its modeling forecast cost assumptions affecting mine reclamation costs at its Jim Bridger generating units that necessitated re-running its modeling for over 50 different resource portfolios. The Commission approved the new filing date of no later than October 18, 2019.

On October 18, 2019, the Company filed its 2019 IRP with the Commission. The Division provides these Comments to the Commission with a focus on compliance with the Commission's Standards & Guidelines and its previous IRP Orders. The Division also provides recommendations to the Commission on suggestions to preserve the integrity of the role of electric resource planning that serves the long-term public interest of Utah ratepayers.

The Company has announced that it does not intend to file a 2019 IRP Update, as it is not feasible given the delay on the 2019 IRP. Therefore, the Division provides recommendations to the Commission on items that the Company needs to incorporate in its 2021 IRP in order to be in compliance for the next IRP. The Division hopes the next IRP will be filed on March 31, 2021, and encourages the Company to make its best efforts to return to the long-standing IRP schedule.

3. Overview of the IRP Process

The Company's 2019 IRP reflects emphasis not just on developing the least-cost, least-risk mix of resources to serve customer load in the future, but a focus on dispatching and delivering a combination of energy resources that reduces greenhouse gas emissions (GHG), reflecting customer demand for clean energy and ensuring compliance with state and federal regulatory obligations.

In its 2017 IRP, the Company stated its primary objective was to develop a least-cost, least-risk preferred portfolio with a "cost-conscious plan to transition to a cleaner energy future."[5] The 2019 IRP goes a step further by stating that it envisions "a future where energy is delivered affordably, reliably and without greenhouse gas emissions."[6] The Action Plan in the 2019 IRP includes the early retirement of certain coal units. These early retirements stemmed from economic analyses that the Company performed on each of its coal units (the coal studies). The coal studies were prompted by the state of Oregon, which passed legislation in 2016 that prohibits utilities from including coal plants in their rates beyond 2030.[7] In addition, Washington state legislators passed a law to transition to 100% clean energy by the year 2045.[8] These are constraints on the Company's system planning that may not result in least-cost, least-risk planning for individual states or the system.

The Company identified portfolio case P-45CNW as the preferred portfolio. The Company's preferred portfolio includes a phased approach to closing down 20 of the Company's 24 existing coal-fired units by 2038 by retiring seven of the coal-fired units years earlier than initially

[5] Docket No. 17-035-16, PacifiCorp's 2017 IRP, April 4, 2017, Vol. I, p. 1.
[6] Docket No. 19-035-02, PacifiCorp's 2019 IRP, October 18, 2019, Vol. 1, p.1.
[7] Oregon Clean Electricity & Coal Transition Plan (S.B. 1547B), signed into law on March 8, 2016. S.B. 1547B, requires the state's major investor-owned electric utilities to largely eliminate the use of coal generation by Jan. 1, 2030, and obtain 50% of power sold to retail customers from renewable energy by 2040. In addition to renewables, the law contains provisions for energy storage and transportation electrification. See: https://olis.leg.state.or.us/liz/2016R1/Downloads/MeasureDocument/SB1547/Enrolled.
[8] On May 7, 2019, Senate Bill 5116 was enacted in Washington, establishing a coal elimination standard, a greenhouse gas neutral standard and a 100% renewable and non-emitting portfolio standard. See: http://lawfilesext.leg.wa.gov/biennium/2019-20/Pdf/Bills/Session%20Laws/Senate/5116-S2.SL.pdf?q=20200127192903 (Section updated 8/12/19).

planned. The retirements will reduce the Company's coal fired generation capacity by nearly 2,800 megawatts (MW) by 2030 and almost 4,500 MW by 2038, resulting in the need to mitigate reliability risk and ensure resource adequacy.

In 2017 the Company introduced Energy Vision 2020, which increased its renewable energy portfolio in an attempt to take advantage of federal tax incentives. The three major components of Energy 2020 are: (1) new wind resources (particularly in Wyoming), (2) the Aeolus-to-Bridger/Anticline transmission line, and (3) repowering of 905 MW of wind resources by the end of 2020, to qualify for full PTCs.[9] The Company's Energy Vision 2020 initiative continues in the 2019 IRP, with near-term network transmission upgrades and a new 400-mile transmission line known as Gateway South. Much of Energy Vision 2020 was contained in the Company's 2017 IRP Action Plan.

The 2019 IRP continues this trend, as the preferred portfolio adds a large amount of wind, solar, and batteries. Certain transmission projects were selected along with the renewables in the 2019 preferred portfolio. The Company states that the expanded transmission infrastructure is needed to support its goal of over 7,000 MW of new wind, solar, and batteries by 2023.[10] As with the 2017 IRP's Energy Vision projects, the 2019 IRP suggests closure of existing facilities based on projections that other resources will be cheaper. The Division renews its suggestion of caution from the dockets resulting from the 2017 IRP (17-035-39, 17-035-40). The decision to close existing facilities based on speculative projections of gas prices, carbon prices, and other uncertain factors should not be taken lightly.

[9] Docket No.17-035-16, PacifiCorp's 2017 IRP Update, May 1, 2018, p. 87.
[10] Docket No. 19-035-02, PacifiCorp's 2019 IRP, October 18, 2019, Vol. I, p. 3. Details of the Preferred Portfolio are found on page 258 of Vol. I of the 2019 IRP. The Company's preferred portfolio includes by 2023: 3,500 MW of new wind; 3,000 MW of new solar; and 600 MW battery storage. This totals 7,100 MW.

4. Modeling Improvements and Changes for 2019

Modeling Overview: 2017 vs. 2019

The Company introduced several modeling improvements for the 2019 IRP. From a bird's-eye view, the 2017 IRP modeling procedure had the following main stages: [11]

1. **Regional haze screening**. This stage developed seven portfolio scenarios based on regional haze compliance strategies. The lowest-cost case was used as "core case 1" in the next screening stage.
2. **Eligible portfolio screening**. This stage evaluated portfolios deemed eligible to be considered for preferred portfolio selection. The Company used the System Optimizer (SO) model to produce scenarios that meet the Company's resource needs and other requirements.
3. **Final screening**. In this stage, the Company used the Planning and Risk (PaR) model to perform stochastic risk analysis of the scenarios from the previous stage.

The 2019 IRP also had three main stages, although the first stage was made up of coal studies, rather than regional haze screenings:[12]

1. **Coal Studies**. This stage had three phases: (1) Unit-by-unit retirement studies, which used the SO model to view the costs of retiring coal units before their operational retirement dates: (2) Studies that expanded Phase One results by using the PaR model, looking at stacked retirements, varying retirement dates, and capacity shortfalls; and (3) Further evaluation of stacked retirement scenarios.
2. **Portfolio screening**. This stage was similar to the 2017 IRP second stage. It evaluated portfolios deemed eligible to be considered for preferred portfolio selection. The Company used the SO model to produce scenarios that meet the Company's resource needs and other requirements. In 2019, a reliability assessment was added to this stage and to the final screening to account for reliability shortfalls that occur when dispatchable resources (e.g. coal) are replaced with intermittent resources (e.g. wind).
3. **Final screening**. In this stage, the Company used the PaR model to perform stochastic risk analysis of the scenarios from the previous stage.

[11] Docket No.17-035-16, PacifiCorp's 2017 IRP, April 4, 2017, Vol. I, pp. 143 et seq.
[12] Docket No. 19-035-02, PacifiCorp's 2019 IRP, October 18, 2019, Vol. I, pp. 172-3.

Modeling Improvements for 2019

The most prominent modeling changes made for the 2019 IRP were the following. These modeling improvements are summarized on pages 18-19 of Volume I of the 2019 IRP and throughout the IRP.

- The first 2017 stage (regional haze screening) was replaced by a series of coal studies, which analyzed the impacts of retiring coal plants earlier than assumed in the 2017 IRP. The results of these coal studies were fed into the development of portfolios.
- When a portfolio is developed and considered, it undergoes a reliability assessment. This most often occurs when flexible, dispatchable resources are supplemented by or replaced with intermittent variable resources. The reliability assessment "uses up to 16 PaR deterministic model runs to assess hourly capacity shortfalls for years 2023 through 2038."[13] This assessment is new for the 2019 IRP modeling.
- When developing portfolio resources for the 2019 IRP, the model was allowed to endogenously select new transmission options. In previous IRPs, transmission upgrades and costs were only "coarsely evaluated in SO model resource selections that required post-modeling assessment of upgrade costs after resource portfolios were developed."[14] In the 2019 IRP, the model was allowed to "view" the costs of certain transmission upgrades and select those upgrades along with associated generation resource additions.
- PacifiCorp improved the storage modeling to "optimize charge and discharge cycles" taking into account the load net of intermittent wind and solar generation.
- PacifiCorp updated some modeling assumptions, including: the granularity of reserve requirements analysis (from monthly in the 2017 IRP to hourly in the 2019 IRP); and capacity contribution values that decline with increasing renewable penetration.

The Division considers the coal studies and the ability of the model to select a new transmission option to have significant impacts. The impacts are reflected in the early retirement of certain coal plants and in transmission projects in the preferred portfolio. These modeling changes, the ability of the model to select and model renewables and batteries together, and the declining prices of renewables and batteries make the preferred portfolio mix in the 2019 quite different than that in the 2017 IRP.

For example, the projected energy mix of the preferred portfolio in the 2017 IRP for the year 2024 was as follows:[15]

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[13] *Id.* at 173.
[14] *Id.* at 18-19.
[15] Docket No. 17-035-16, PacifiCorp's 2017 IRP, April 4, 2018, Vol. I, Figure 8.70, p. 240.

46% coal
20% natural gas
5% hydroelectric
20% renewables[16]
7% new class 2 DSM
2% other

In contrast, the same year (2024) in the 2019 projections has the following projected energy mix:

40% coal
9% natural gas
5% hydroelectric
40% renewables
5% energy efficiency
1% other

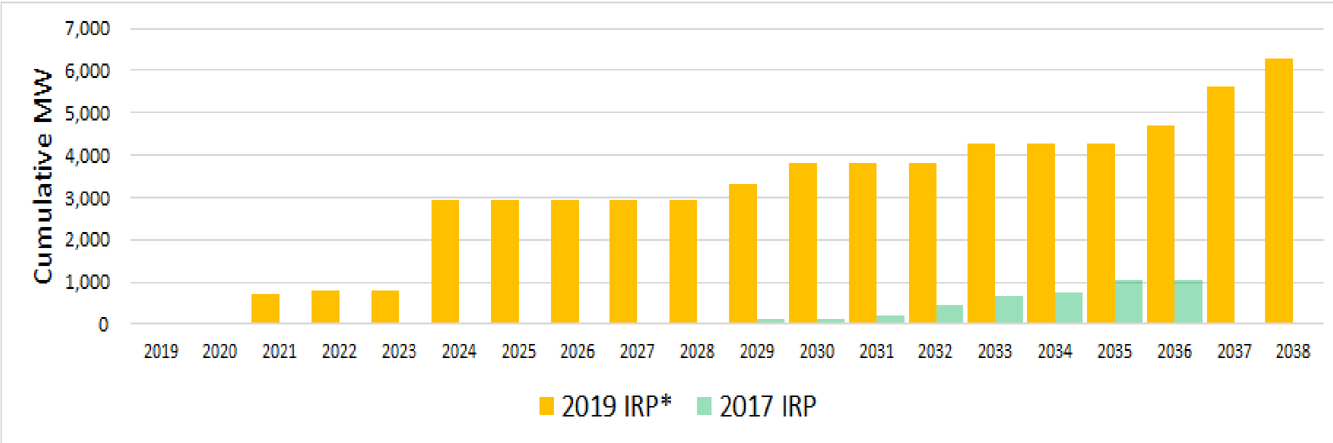
The projected energy mix of coal plus natural gas in 2024 in the 2017 IRP was 66%; in the 2019 IRP it is 49%. The projected energy mix of renewables in 2024 in the 2017 IRP was 20%; in the 2019 IRP it is 40%.[17]

The projected mix at the end of the 2019 IRP forecast period is even more striking: in the 2019 IRP, the projected energy mix in 2038 is expected to have 26% coal and natural gas, compared to 50% renewables. In contrast, the 2017 had the energy mix in 2036 (the last projection year of the IRP) at 61% coal and natural gas, and 21% renewables.

An example of the accelerated addition of renewables in the 2019 IRP as compared to the 2017 IRP can be illustrated by Figure 1.3 in Volume I of the 2019 IRP: it depicts the planned added solar capacity in the 20-year 2019 IRP period, as compared to the projections in the 2017 IRP (2019 projections are the darker yellow bars, and 2017 projections are the green bars).[18]

[16] Note that in these discussions, "renewables" does not include hydroelectric power.
[17] Docket No. 19-035-02, PacifiCorp's 2019 IRP, October 18, 2019, Vol. I, Figure 8.44, p. 257.
[18] *Id.* at 9.

2019 IRP Preferred Portfolio New Solar Capacity vs. 2017 IRP (Figure 1.3 in IRP)



5. Review of Load Growth and Resource Deficit

Generally, the Company's load forecast "is developed by forecasting the monthly sales by customer class for each jurisdiction."[19] The Company uses different forecasting methods for different classes. The main classes are residential, commercial, industrial, irrigation, and street lighting. The separation of irrigation into a separately modeled class is an update from the 2017 IRP.

Load Forecast

The Division reviewed the load forecast methodology for the 2019 IRP and its use in the load and resource balance. The load forecast used was from September 2018.[20] Three of the factors that are driving trends across the system are as follows:

- Higher projected demands from data centers are driving up projected commercial energy usage.
- Higher projected numbers of residential consumers are helping drive up the projected residential energy usage; and
- Use-per-consumer for the residential class is still declining, thanks to energy efficient appliances and lighting, and a shift from single-family housing to multi-dwelling units.

[19] Docket No. 19-035-02, PacifiCorp's 2019 IRP, October 18, 2019, Vol. II, Appendix A, p. 13.
[20] *Id.* at 1.

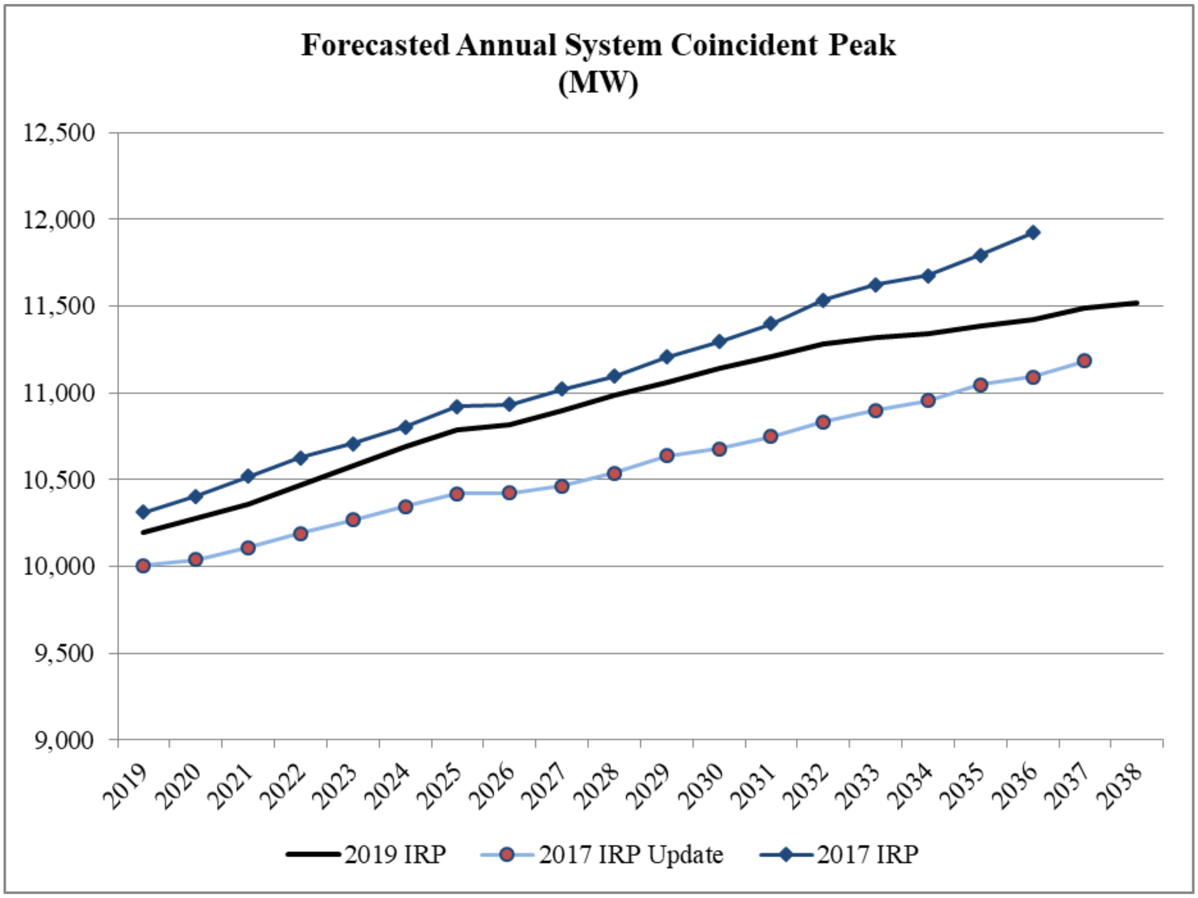
Residential use per customer is changing due to increased energy efficiency in lighting and the replacement of older electric appliances. The residential sales forecast has been developed from a use-per-customer forecast multiplied by the number of customers. The commercial sales forecast has been developed from historical sales volumes, and the industrial sales forecast has been developed using regression analysis along with trend and economic variables. The forecasts for very large industrial customers have been developed from information provided by the individual customer.

Utah customers account for approximately 43 percent of the forecast load at generation and represent the largest increase to the system over the 10-year forecast period in MWh.[21] The forecasted compound annual growth rate (CAGR) of load in Utah is projected to be 0.97% over the ten-year forecast period, compared to the total system load CAGR of 0.87%.[22] The projected growth in Utah is similar to that in prior IRP filings (in the 2017 IRP, the Utah CAGR for the 10-year forecast period was 0.93%).

The system coincident peak load is the annual maximum hourly load on the system. The Company compared the system coincident peak load forecast for the current and past two IRPs for the years 2019 through 2036.[23] The results trend similarly, but the 2017 IRP Update forecast was lower than that of the 2017 IRP forecast, for every year of the shown period. As shown below, the 2019 IRP forecast is in between the two previous forecasts.

[21] *Id.* at 2. Oregon has a higher forecasted increase in percentage terms.
[22] *Id.*
[23] Docket No. 19-035-02, PacifiCorp's 2019 IRP, October 18, 2019, Vol. I, p. 10.

Load Forecast Comparison between Recent IRPs (Before Incremental Energy Efficiency Savings) (Figure 1.6 in 2019 IRP)



In general the Division finds that the load forecast was conducted with modeling and techniques appropriate to the industry. The Division is concerned, however, that the forecasted load growth rates are consistently higher than actual growth rates (see Section 6 for more on this issue). One area that the Division recommends improving is the EV forecast. In the Technical Conference, the Division asked the following:

> Please provide the projected EV counts by year and by state that were included in the load forecast. How were these projections formulated and how are they reflected in the Company's load forecast?[24]

[24]Docket No. 19-035-02, Division of Public Utilities' Questions for the December 10, 2019 Technical Conference, December 10, 2019, at: https://pscdocs.utah.gov/electric/19docs/1903502/311414DPUQDec102019TechConf12-9-2019.pdf

The Company responded in the technical conference as follows: "The quick answer to that is we didn't explicitly layer in an EV forecast to the IRP. The IRP forecast is based on historical customer billing data, which has EV load embedded in that billing data."[25] The Division assumes this means that the EV load was simply present in past billing data, which in turn was used to estimate the econometric models used in the load forecast. As the number of EVs on the system grows, the Division expects this method of accounting for EV usage will be insufficient.

- The Division recommends that separate EV forecasts, with sensitivity scenarios, be included in the load forecast used in the 2021 IRP. The Company can also use this data for EV time-of-use and load management programs.

6. Forecasts and Uncertainty: Critical Role of Forecast Inputs and Assumptions

The least-cost, least-risk planning process requires projections of load, natural gas prices, and other model inputs. It is critical for model assumptions to be non-arbitrary and justified by available data. The Division analyzed the Company's forecasts presented in the 2019 IRP and, where possible, compared these forecasts in previous IRP reports, and to actual results.

Annual Energy Load Forecast

PacifiCorp utilizes software and services, including ITRON and SAE, to record, model and forecast. PacifiCorp performs a historical comparison to forecasted results in its analysis and forecast methodology. PacifiCorp developed alternative load growth scenarios for system demand and presented its long-term preferred forecast for each state and the system summarized in IRP 2019 Volume II, Appendix A – Load Forecast Details.

PacifiCorp's 2019 IRP Table A.1 estimates the forecasted load at generation over a 20-year period.[26] PacifiCorp employed "econometric models that use historical data and inputs such as regional and national economic growth, weather, seasonality, and other customer usage and

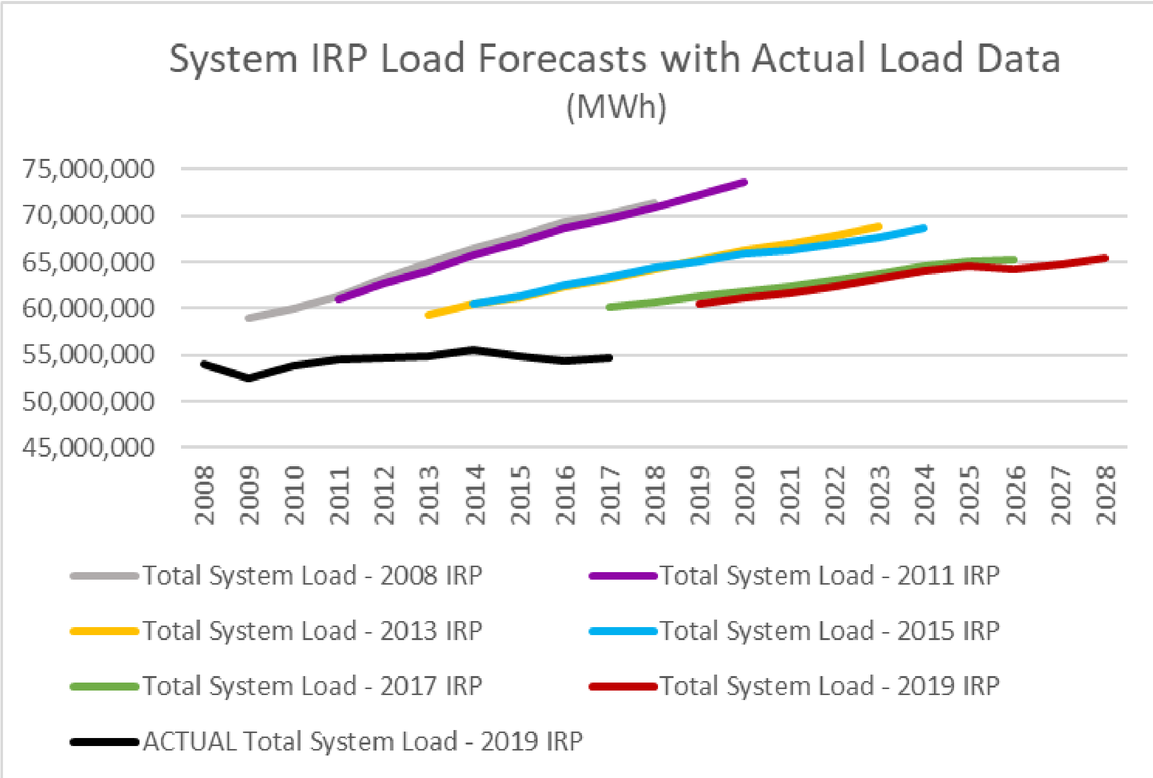
[25] Docket No. 19-035-02, Audio of Technical Conference held December 10, 2019, starting at 1:54:25, at https://www.youtube.com/watch?v=37DgOVUx8tU
[26] Docket No. 19-035-02, PacifiCorp's 2019 IRP, October 18, 2019, Vol. II, Appendix A, p.2 ("Forecasted Annual Load, 2019 through 2028 (Megawatt-hours), at Generation, pre-DSM").

behavior changes" in the development of this table.[27] PacifiCorp provided the Division with an Excel file entitled "Load Forecast History" that contained the information from Table A.1 as well as the forecasted annual load data tables from each of PacifiCorp's prior IRP filings since 2008.

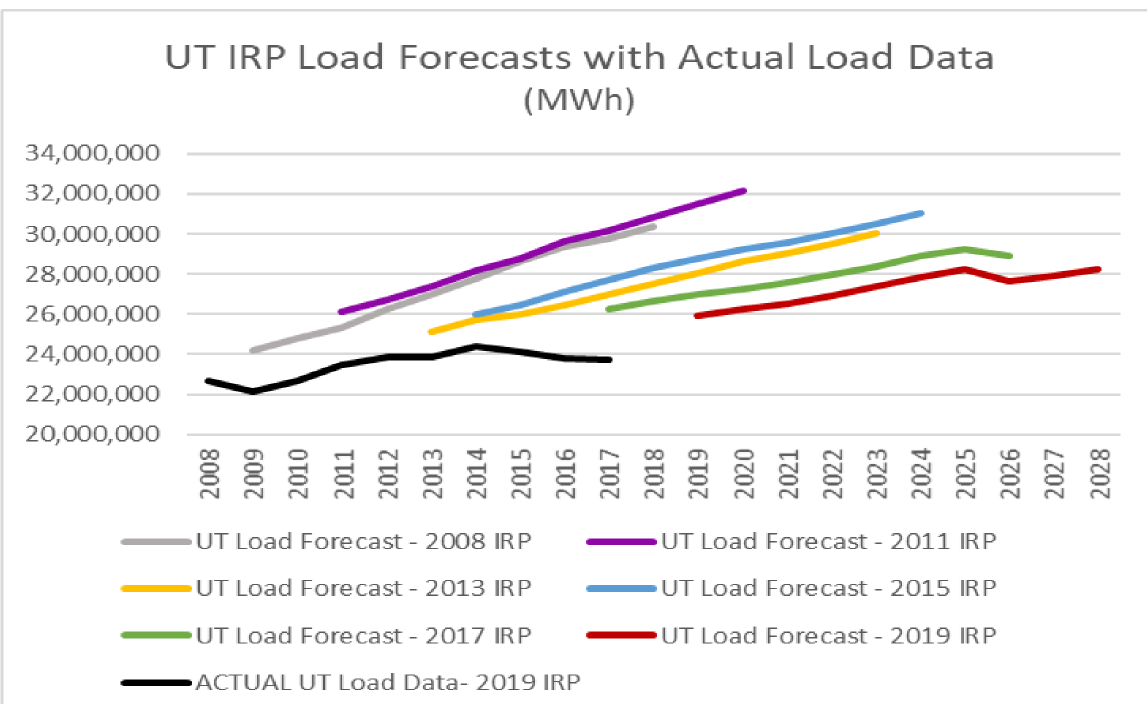
Table A.5 in the 2019 IRP records actual retail sales, excluding sales for resale.[28] The Division compared the information from the Excel file entitled Load Forecast History (which includes Table A.1) with PacifiCorp's Table A.5 for Utah and the total system in the following two charts. The black line is the actual load data from Table A.5 of the IRP, and the colored lines are from the forecasted annual loads (Table A.1) from the 2019 IRP and from past IRPs. It should be noted that the data from Table A.5 and A.1 are not exactly analogous: Table A.5 is actual retail sales, weather normalized (not including sales for resale), and so is post line losses. Table A.1 is forecasted load at generation, pre-DSM. The important takeaway is the annual growth rate of the projections vs. the growth rate in the actual data; these growth rates are examined in subsequent tables.

[27] *Id.* at 1.
[28] *Id.* at 11 ("Weather Normalized Jurisdictional Retail Sales 2000 through 2017")

Division Figure 1



Division Figure 2



As observed in the Division's comparison graphs, Division Figures 1 and 2, PacifiCorp's forecast energy growth rate has been overestimated in all prior IRPs since 2008. Using the data from PacifiCorp's Tables A.1 and A.5 the Division quantified this load overestimation in the following calculation and comparison of Average Annual Growth Rate (AAGR):

Division Table 1

Period	Forecast SYSTEM Load (2019 IRP Table A.1 data) AAGR	Actual SYSTEM Retail Sales (2019 IRP Table A.5 data) AAGR	Difference
2009 - 2017	1.93%	0.15%	1.77%
2010 - 2017	1.94%	0.55%	1.38%
2011 - 2017	1.92%	0.06%	1.86%
2012 - 2017	1.84%	0.00%	1.84%
2013 - 2017	1.77%	-0.06%	1.82%
2014 - 2017	1.67%	-0.51%	2.18%
2015 - 2017	1.65%	-0.17%	1.81%

Division Table 2

Period	Forecast UTAH Load (2019 IRP Table A.1 Data) AAGR	Actual UTAH Retail Sales (2019 IRP Table A.5 Data) AAGR	Difference
2009 - 2017	2.27%	0.51%	1.76%
2010 - 2017	2.27%	0.86%	1.40%
2011 - 2017	2.27%	0.19%	2.08%
2012 - 2017	2.21%	-0.12%	2.33%
2013 - 2017	2.16%	-0.13%	2.28%
2014 - 2017	2.06%	-0.98%	3.04%
2015 - 2017	2.06%	-0.85%	2.91%

Long-term forecasts and modeling are subject to considerable uncertainty. Accurately forecasting load growth is an important component of risk assessment and management within the IRP process, and load is among the most important variables affecting future revenue requirement. A significant overestimation could impact resource planning and future resource allocations.

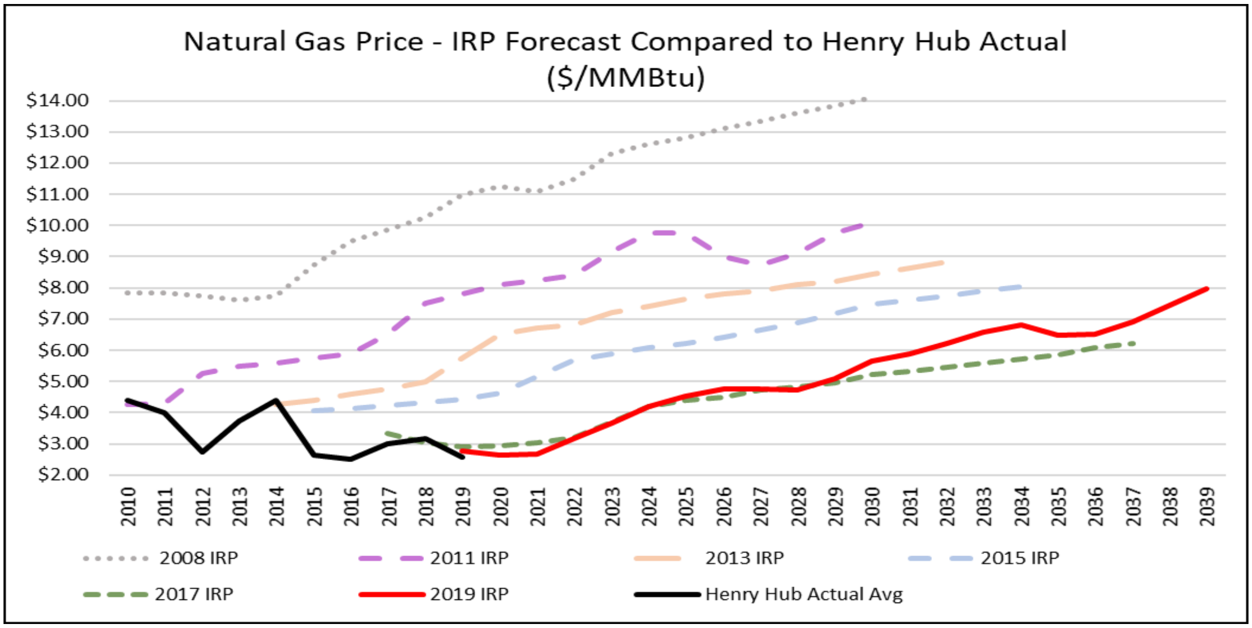
Natural Gas Forecast

PacifiCorp is exposed to natural gas price risk due to its natural gas-fired generating fleet and the interrelationship of natural gas to other fuel sources. A price change in natural gas may sway the price of electricity. For IRP modeling purposes PacifiCorp used the official forward price curve (OFPC) and seven scenarios. The scenarios are alternative spot price forecasts, and the OFPC represents PacifiCorp's official quarterly outlook. The OFPC is compiled "using market forwards, followed by a market-to-fundamentals blending period that transitions to a pure fundamentals-based forecast."[29]

PacifiCorp's Figure 1.8 records the base case medium scenario based on prices in the forward market and on projections from market experts.[30] The Division compared the natural gas price projections found in Figure 1.8 and in prior IRPs since 2008, with the actual Henry Hub spot price history. The following graph shows the Division's findings:

[29] Docket No. 19-035-02, PacifiCorp's 2019 IRP, October 18, 2019, Vol. I, p. 180.
[30] *Id*. at 11 (Comparison of Power Prices and Natural Gas Prices in Recent IRPs).

Division Figure 3



The Division's comparison graph, Figure 3, demonstrates that the future price of natural gas has been overestimated in IRPs since 2008. Henry Hub is used here as a rough proxy of natural gas price trends. The Division further quantified this forecasted overestimation in the following comparison of AAGR:

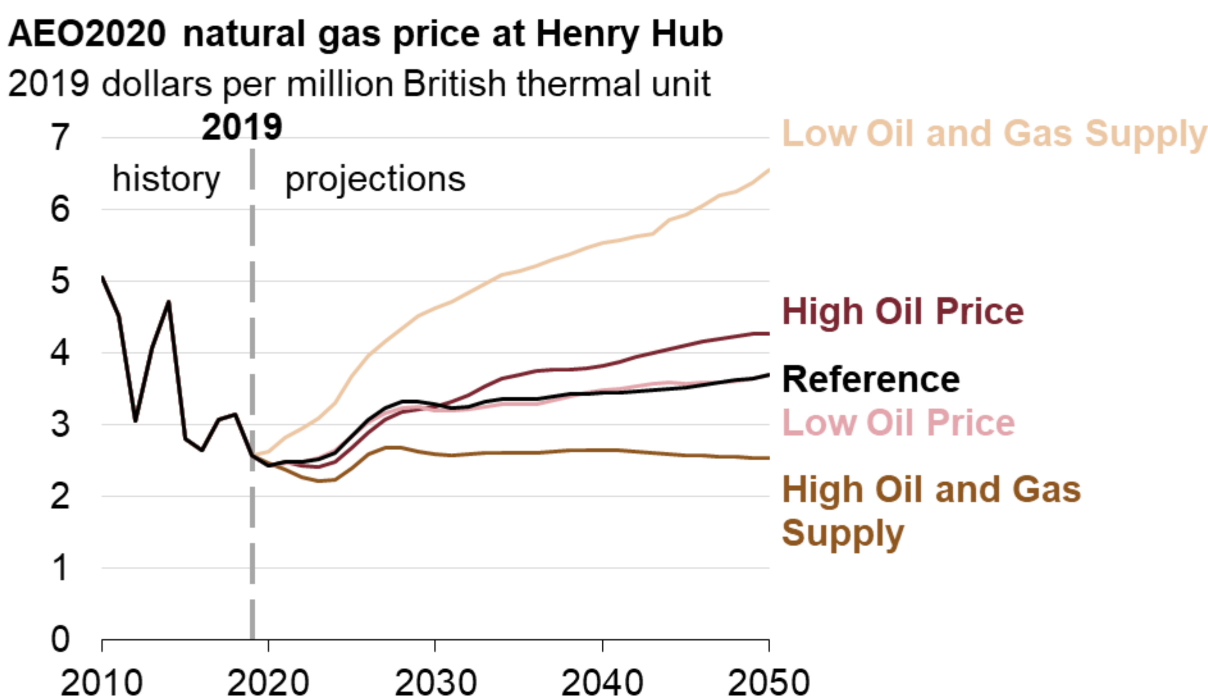
Division Table 3

Period	PacifiCorp Forecasted Natural Gas Price (2008-2019 IRP Data) AAGR	Actual Natural Gas Henry Hub (EIA Spot Price Data) AAGR	Difference
2010 - 2019	5.56%	-2.83%	8.38%
2011 - 2019	5.31%	-2.08%	7.38%
2012 - 2019	5.27%	2.08%	3.19%
2013 - 2019	4.50%	-3.48%	7.98%
2014 - 2019	5.16%	-7.74%	12.89%
2015 - 2019	5.42%	0.36%	5.06%
2016 - 2019	4.72%	1.93%	2.78%
2017 - 2019	3.89%	-6.46%	10.35%

The Division also compared PacifiCorp's 2019 IRP natural gas forecast with the natural gas price at the Henry Hub forecasted in the January 29, 2020 Annual Energy Outlook 2020 with projections to 2050 (AEO2020). The AEO2020 was prepared by the U.S. Energy Information Administration (EIA).

The AEO2020 modeled 5 case projections for natural gas prices at Henry Hub through 2050. Each projected scenario includes different assumptions about economic growth, energy supply, and technological progress. The EIA forecast each of these five scenarios in the following chart:

Division Figure 4



Annual Energy Outlook 2020 with projections to 2050 (AEO2020), January 29, 2020, p.17

The Reference scenario was chosen by the EIA to be the best fit to its projected key assumptions. Under the Reference scenario, projected natural gas prices would be $3.5 per million British thermal units (Btu) through 2035 and would remain lower than $4 per million (Btu) through

2050. In comparison, PacifiCorp forecasts the price of natural gas at almost $8 per million (Btu) by 2039.[31]

PacifiCorp's forecast for natural gas was projected higher than EIA's worst-case scenario shown on EIA's graph as "Low Oil and Gas Supply." This scenario has the highest natural gas price relative to the other cases, including the Reference case. Under this scenario, natural gas would only reach $6.5 per million (Btu) by 2050 due to the assumed level of scarcity inflating the price of natural gas.

This comparison of EIA's and PacifiCorp's forecasts was provided as an outside reference and view on the trending future price of natural gas, not to imply an indication of preference in any particular model or forecasting methodology. From past conversations with the Company, the Division acknowledges that EIA forecasts are not usable for the Company's modeling, for a number of reasons. The comparison with the EIA forecast is simply a reminder of the large impact that different natural gas price forecasts can have on the preferred portfolio and other aspects of the IRP.

Relying on overestimated forecasts could lead to ineffective decisions in resource selection and allocation. The Division recommends that PacifiCorp compare IRP projections to actual historical results and provide its findings in the next IRP (similar to Division Figures 1 and 3, with units adjusted so that an analogous comparison is made). PacifiCorp should include direct and detailed comparisons of forecasts to actual results in all future IRPs.

7. Regional Capacity and Reliability

In Appendix J of the IRP, the Company addresses its Western Resource Adequacy Evaluation. In its Order for the Company's 2008 IRP, the Utah Commission directed the Company to "include an analysis of the adequacy of the western power market to support the volumes of purchases on which the Company expects to rely…"[32] The Commission directs the Company to use analysis from Western Electricity Coordinating Council (WECC) as a source for this evaluation. The

[31] The Division is aware that Figure 1.8 in the 2019 IRP is in nominal $, and that the EIA chart is in 2019 $. The Division requests that the Company reproduce Figure 1.8 in 2019 $ in its reply comments for a better comparison.
[32] Docket No. 19-035-02, PacifiCorp's 2019 IRP, October 18, 2019, Vol. II, Appendix J, p. 147 (citing Docket No. 09-2035-01, Report and Order, 2008 Integrated Resource Plan, p. 30).

Company stated that the WECC Power Supply Assessment was not updated in time for the 2019 IRP, and so it used the North American Electric Reliability Corporation (NERC) Long Term Reliability Assessment (LTRA) (upon which past WECC reports have partially relied).

The NERC LTRA evaluated the period from 2019 to 2028 and assesses the planning reserve margin based on: (1) anticipated resources (existing capacity, capacity that is under construction/approved, firm contracts); and (2) Prospective resources (existing capacity with limitations, capacity additions not yet approved, non-firm contracts). NERC concluded there could be planning margin shortfalls in certain regions by 2027 or 2028.[33]

Table J.5 – Planning Reserve Margin Shortfalls By Subregion with Anticipated Resources

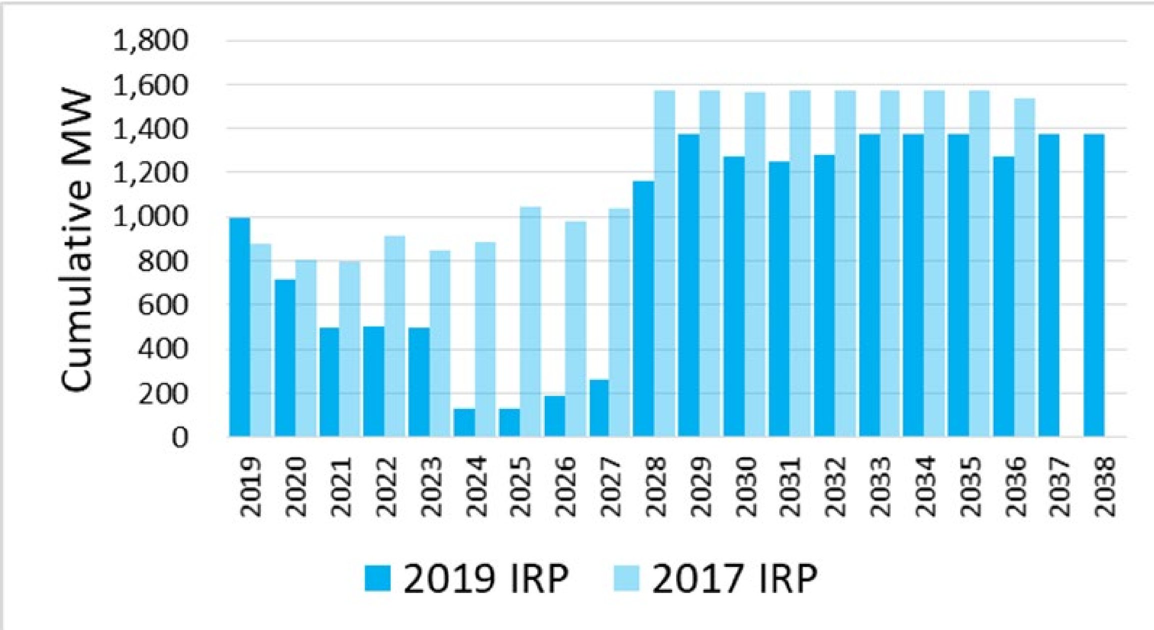
Table J.5 –Planning Reserve Margin Shortfalls by Subregion with Anticipated Resources

Shortfalls Assuming Anticipated Reserve Margin											
U.S. WECC Subregion	Peaking Assumption	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
NWPP	Summer	7.9%	6.2%	5.1%	3.2%	4.3%	4.2%	4.3%	4.3%	7.2%	2.9%
RMRG	Summer	16.9%	9.8%	8.4%	7.1%	5.1%	3.7%	2.3%	1.2%	0.1%	**-1.2%**
SRSG	Summer	15.7%	14.3%	12.6%	9.4%	6.4%	4.5%	2.5%	1.0%	**-2.0%**	**-3.3%**
CA/MX	Summer	10.9%	18.3%	12.2%	11.6%	12.5%	8.6%	8.4%	8.9%	8.7%	8.2%

[33] *Id.* at 148, 150.

2019 IRP Preferred Portfolio FOTs—Summer vs. 2017 IRP

(Figure 1.9 in IRP)



- The Division recommends keeping a close eye on regional resources in the 2023-2027 period, and the projected jump in summer FOTs in 2028. Action may be required in the next IRP if these trends continue.

8. Commission Standards and Guidelines

The Commission in its Report and Order in Docket No. 90-2035-01 dated June 18, 1992 outlined nine Procedural Issues that guide the IRP process.[34] That same 1992 Report and Order listed eight Standards and Guidelines, some with subparts, which the Company should follow in the IRP process. The two tables in Appendix A list the nine Procedural Issues and the eight Commission Standards and Guidelines found in the 1992 Report and Order.

The Division notes that its approach in these Comments is consistent with the third procedural issue ("Prudence Reviews of new resource acquisitions will occur during ratemaking proceedings."). The discussion of that third procedural issue states that "acknowledgement of an

[34] Docket 90-2035-01, Report and Order, June 18, 1992.

IRP will not foreclose full prudence examination of the resource acquisition at an appropriate later time."[35] The Commission, in its Report and Order for the 2017 IRP, echoed this approach:

> Acknowledgment of an IRP means it substantially complies with the regulatory requirements of the planning process. Acknowledgment of an IRP does not constitute regulatory approval for any specific PacifiCorp resource acquisition decision or strategy for meeting its obligation to serve.
>
> …
>
> Utah Code Ann. § 54-17-302 requires PacifiCorp to obtain PSC approval of any significant energy resource decision before it constructs or enters into a binding agreement to acquire the resource, unless PacifiCorp requests, and the PSC grants, a waiver. Accordingly, IRP acknowledgment and resource solicitation/acquisition decision approval processes are separate.[36]

The Division emphasizes that acknowledgement does not foreclose disagreement with specific IRP assumptions in future proceedings. Therefore, the Division reserves the right to contest the appropriateness of certain IRP assumptions and inputs in later proceedings, especially prudence review proceedings, even if it did not object to the particular assumptions in these Comments.

In Volume II, Appendix B, the Company's points the reader to where in its IRP chapters "the Company believes" the IRP has addressed each respective Standard and Guideline. The Division will comment only on those Standards and Guidelines which need clarification or for which the Division determines the standard has not been met. The IRP action plan items will be addressed in a separate section to follow.

The Company did not adequately meet the second portion of Guideline 3:

> #3. The IRP will be developed in consultation with the Commission, its staff, the Division of Public Utilities, the Committee of Consumer Services, appropriate Utah state agencies and interested parties. PacifiCorp will provide ample opportunity for public input and information exchange during the development of its Plan.

The Company's inability to distribute meeting materials in advance of public input meetings compromised the ability of stakeholders to examine and question the materials at stakeholder meetings, thus impairing the public input process and transparency goal of the IRP. The Division has made repeated requests in this area. For the 2017 IRP, the Division noted that the Company

[35] *Id.* at 6.
[36] Docket No. 17-035-16, Report and Order on PacifiCorp's 2017 IRP, March 2, 2018, p. 8 and p. 12.

had "failed miserably" with respect to filing meeting materials in a timely manner, and requested the Commission to "direct the Company to file meeting materials at least one week in advance."[37] The Commission did not directly accept the Division's one-week recommendation in its 2017 Order, although it did note that in its order for the 2009 IRP, it directed the Company to provide materials "one week prior to the public input meeting."[38]

Receiving the meeting materials days in advance is imperative if stakeholders are to formulate meaningful and helpful questions. The Division therefore again requests the Commission direct the Company to file meeting materials several days ahead of the meeting. Future violations of this Guideline may cause the Division to recommend non-acknowledgement of an IRP based on this factor alone. Untimely provision of meeting materials may also violate Utah Code Section 54-7-25, which provides penalties for failure to comply with Commission orders.

- The Division finds that the Company's conduct with respect to Guideline 3 was insufficient, as it did not provide meeting materials until just before the public meetings. The Division recommends that the Commission require the Company to provide meeting materials at least three full business days in advance of public meetings.

9. Public Input Process

In its Comments for the 2017 IRP, the Division criticized the Company for canceling and postponing general IRP meetings.[39] In 2017, the Company held a general meeting on September 22-23, 2017, and one on March 2-3, 2017, with no general meeting in between, a span of over five months.[40] Overall, the Division noted that only five general meetings were held.[41] In light of these and other concerns, the Division recommended that "the Commission order the Company to hold monthly, two-day (6-8 hour day) meetings through the 'yearlong development period' and at 'each decisive step' of the IRP process."[42]

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[37] Docket No. 17-035-16, Comments on PacifiCorp's 2017 IRP, October 24, 2017, p. 25.
[38] Docket 17-035-16, Report and Order on PacifiCorp's 2017 IRP, March 2, 2018, p. 22, footnote 24. (citing *In the Matter of the Acknowledgment of PacifiCorp's Integrated Resource Plan*, Docket No. 09-2035-01, *Report and Order,* issued April 1, 2010 at 54).
[39] Docket No. 17-035-16, the Division's Comments on PacifiCorp's 2017 IRP, October 25, 2017, p. 14.
[40] *Id.*
[41] *Id.* at 17.
[42] *Id.* at 19.

The Commission in its Order in the 2017 IRP Docket found that PacifiCorp did not comply with Guideline 3. The Commission declined to "micromanage" the meeting process beyond the language in Guideline 3, although they did "encourage PacifiCorp and stakeholders to review the DPU's recommendations at the start of the next IRP process."[43]

PacifiCorp has made good progress in improving its public input process, with one exception that the Division discussed in a previous Section. By the Division's count, PacifiCorp has held 17 general public meeting for the 2019 IRP (three of those were conference calls). However, the Division notes that one reason for the numerous public meetings was that the IRP filing deadline was delayed twice. In general, in contrast to the 2017 IRP meetings, the 2019 meetings were not rushed, and participants were given time to ask questions. The Division also notes that the Company handled the subject of the possible early coal plant closures at the public meetings with tact and sensitivity, given the effect on coal workers and communities.

The delay of the filing of the IRP from the original date of March 31, 2019, to August 1, 2019, then to October 18, 2019 was caused by several factors. The coal study added an extra step that was not present in earlier IRPs, and this issue was the subject of multiple general meetings and added reliability analysis. Portfolio model runs also had to be re-run after the Company determined that mine reclamation costs were not being stated correctly.[44] While the delays were unfortunate, the Division recommended that the extensions be approved by the Commission, primarily because forcing the Company to submit an IRP with incomplete or incorrect modeling analysis would be counterproductive.

In general, the Company has also replied satisfactorily to Stakeholder Feedback Forms; these are collected on the Company's website. The Company also ran several modeling scenarios at the request of stakeholders; this cooperation is appreciated by the Division. In general, the Division finds the public input process to be sufficient, with the caveat mentioned in the previous Section.

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[43] Docket 17-035-16, Report and Order on PacifiCorp's 2017 IRP, March 2, 2018, p. 22.
[44] See, e.g., 2019 Integrated Resource Plan (IRP) Stakeholder Conference Call July 18, 2019, slides 2-3, available at: https://www.pacificorp.com/content/dam/pcorp/documents/en/pacificorp/energy/integrated-resource-plan/2019-irp/2019-irp-presentations-and-schedule/2019-07-18%20-%20General%20Public%20Meeting.pdf

10. Transmission Projects

In its Comments for the Company's 2017 IRP, the Division stated the following about transmission projects:

> The Division recommends the Commission order the Company to come up with a way to value all future segments of Energy Gateway that takes into account the costs and benefits not modeled in the IRP. The Company must come up with a way other than sensitivities to determine various transmission segments before continuing future Gateway segments and before acknowledgement of transmission projects in an IRP can move forward.[45]

In response to the Division's Comments, the Commission in its Order stated as follows:

> We find the DPU's recommendations reasonable to ensure resources are evaluated on a consistent and comparable basis. We expect PacifiCorp and stakeholders to review the DPU's recommendations at the start of the next IRP process.[46]

The main way in which the Company improved the modeling with respect to transmission projects was to allow the model to endogenously select new incremental transmission projects (and their associated costs) along with new resource additions.[47] The transmission options that were available for the model to select are listed in Table 6.11 in the IRP.[48] The transmission projects that were included in the 2019 IRP preferred Portfolio are listed in Table 1.1 of the IRP, which is reproduced below.

[45] Docket No. 17-035-16, Division's Comments on PacifiCorp's 2017 IRP, October 25, 2017, p. 34.
[46] Docket No. 17-035-16, Report and Order on PacifiCorp's 2017 IRP, March 2, 2018, p. 43.
[47] Docket No. 19-035-02, PacifiCorp's 2019 IRP, October 18, 2019, Vol. I, p. 168.
[48] *Id.* at 169.

2019 IRP—Transmission Projects Included in the 2019 IRP Preferred Portfolio (Table 1.1 in 2019 IRP)

Year	Resource(s)	From	To	Description
2023	69 MW Wind (2023) 231 MW Solar (2024)	Within Southern UT Transmission Area		Enables 300 MW of interconnection: UT Valley 345-138 kV + 138 kV reinforcement ($8m)
2024	354 MW Solar (2024)	Within Bridger WY Transmission Area		Reclaimed transmission upon retirement of Jim Bridger 1 ($0)
2024	674 MW Solar (2024)	Within Northern UT Transmission Area		Enables 600 MW of interconnection: Northern UT 345 kV reinforcement ($30m)
2024	1,920 MW Wind (2024)	Aeolus WY	UT North	Enables 1,920 MW of interconnection with 1,700 MW of TTC: Energy Gateway South ($1,752m)
2024	395 MW Solar (2024) 10 MW Wind (2029)	Within Yakima WA Transmission Area		Enables 405 MW of interconnection: local reinforcement ($3m)
2024	359 MW Solar (2024)	Within Bridger WY Transmission Area		Reclaimed transmission upon retirement of Jim Bridger 2 ($0)
2030	1,040 MW Wind (2030) 60 MW Wind (2032)	Goshen ID	UT North	Enables 1,100 MW of interconnection with 800 MW of TTC ($254m)
2030	500 MW Solar (2030)	Within Southern UT Transmission Area		Enables 500 MW of interconnection: UT Valley local area reinforcement ($206m)
2033	475 MW Solar (2033)	Within Southern OR Transmission Area		Enables 475 MW of interconnection: Medford area 500 kV-230 kV reinforcement ($102m)
2036	419 MW Solar (2036)	Yakima WA	Southern OR	Enables 430 MW of interconnection with 450 MW of TTC: Yakima WA to Bend OR 230 kV ($255m)
2037	909 MW Solar (2037)	Southern UT	Northern UT	Reclaimed transmission upon retirement of Huntington 1-2 ($0)
2037	443 MW Gas (2037)	Within Willamette Valley OR Transmission Area		Enables 615 MW of interconnection: Albany OR area reinforcement ($40m)
2037	370 MW Gas (2037)	Within Southwest WY Transmission Area		Enables 500 MW of interconnection: separation of double circuit 230 kV lines ($39m)
2038	702 MW Solar (2038)	Within Bridger WY Transmission Area		Reclaimed transmission upon retirement of Jim Bridger 3-4 ($0)

In general the Division finds the modeling improvement that allows transmission projects to be endogenously selected meets the Commission's recommendation in the 2017 IRP Order. However, the Division also notes that some of the transmission projects from 2030 onward are based on load forecasts and other assumptions that may or may not come to pass. This is especially true in light of the Division's concern that the Company consistently overestimates its future load (see Section 6 of these Comments). The Division points to the (1) 2030 $206 million Southern Utah project, (2) the 2033 $102 Southern Oregon project, and (3) the 2036 $255 million Yakima to Bend projects as expensive transmission upgrades that need further evaluation in light of future load growth and resources needs. Commission acknowledgement of this IRP should not preclude Division evaluation of the necessity and prudence of these projects.

The Division also notes that some transmission projects are not available to be endogenously selected by the model. For example, the Boardman to Hemingway Energy Gateway project (B2H) and Hemingway to Cedar Hill (Segment E) were not available to be selected and so are not in Table 6.11. The Company explains why in its response to Oregon Public Utility Commission Data Request 91.[49] The Company did manually run B2H and Segment E in model runs, but these cases were tacked on, not endogenously selected (as was the case with all transmission in the 2017 IRP). B2H and Segment E were not analyzed in as much detail as was Energy Gateway South.

The Division finds it difficult to properly assess the Company's claim that the Energy Gateway South transmission project (Aeolus to Mona, $1,752 million) is part of the least-cost, least risk portfolio on the timeline presented. The Company reports that:

> The Aeolus-to-Mona transmission segment was endogenously selected by the SO model to come online by the end of 2023 in 34 out of these 35 resource portfolios, and was selected to come online by the end of 2023 in all subsequent resource portfolios developed to refine cost-and-risk analysis for top-performing cases.[50]

The timing is based on the PTC credit: "Timing of construction is driven by the phase-out schedule of federal PTCs, particularly the 2023 in-service requirements for 40 percent PTC eligibility…"[51]

The Division is not clear how recent changes in the PTC expiration dates might affect the transmission analysis. A recent federal appropriations package appears to have extended PTCs for another year.[52] The Company of course cannot be expected to re-do its entire analysis at this late date. The Division notes that the Oregon Public Utility Commission Staff has noted this issue and requested a re-run of the preferred portfolio.[53] The Division will be interested in this and similar analyses when the CPCN for Gateway South comes before the Commission.

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[49] Oregon Docket LC-70, Staff's Comments, Jan. 1, 2020, Attachment A p. 14. Available at: https://edocs.puc.state.or.us/efdocs/HAC/lc70hac1479.pdf

[50] Docket No. 19-035-02, PacifiCorp's 2019 IRP, October 18, 2019, Vol. I, p. 74.

[51] *Id.*

[52] H.R. 1865 (*Further Consolidated Appropriations Act*). See, e.g., *Trump signs legislation to boost DOE funding, extend wind power credit*, S&P Global Market Intelligence, Dec. 23, 2019, available at: https://www.spglobal.com/marketintelligence/en/news-insights/trending/oqglr5awktaxpnbn_7xohq2

[53] Staff's Initial Comments, Docket No. LC 70, In the Matter of PACIFICORP, dba PACIFIC POWER, 2019 Integrated Resource Plan, Jan. 10, 2020, p. 25-6. Available at https://edocs.puc.state.or.us/efdocs/HAC/lc70hac1479.pdf

It is also not clear to the Division how Action Item 2b in the Action Plan fits in with the Gateway South project. Is the Company assuming that the winner of the all-source RFP will be wind that is serviced by Gateway South (i.e. Wyoming wind)? Is the Division correct in assuming that if the all-source RFP is won by southern Utah solar, that Gateway South will be severely underutilized in 2024? The Division also notes that it is not clear whether the all-source RFP will specify a particular capacity.

In addition, it is not clear to what extent the receipt of the PTC credits (and thus the justification for Gateway South to be in service at the end of 2023) relies on the approval of interconnection queue reform (see bullet from Action Item 2b: "In Q2 2020, receive approval from FERC to reform the interconnection queue").[54] When does the Company expect the reform to be enacted? Does the Company expect queue reform to be approved before the all-source RFP is issued? Does the reform affect the all-source RFP at all—for example, if reform is delayed or denied, does that affect the all-source action plan? If reform is enacted, does the Company expect that would increase or decrease the amount of QFs for the years 2020 to 2023?

For these reasons the Division considers the transmission analysis to be inconclusive. The Division requests clarification on the following questions in the Company's reply comments.

- The Division requests that the Company explain how the changes in the PTC expiration dates affect the timing of Gateway South, if at all. Please provide any analysis done regarding the effect of these changes on the preferred portfolio.
- Is the Company assuming that the winner of the all-source RFP will be wind that is serviced by Gateway South (i.e. Wyoming wind)? Is the Division correct is assuming that if the all-source RFP is won by, say, southern Utah solar, that Gateway South will be severely underutilized in 2024? Will the RFP specify a particular capacity being sought?

[54] Docket No. 19-035-02, PacifiCorp's 2019 IRP, October 18, 2019, Vol. I, p 24.

- When does the Company expect the queue reform to be enacted? Does the Company expect queue reform to be approved before the all-source RFP is issued? Does the reform affect the all-source RFP at all—for example, if reform is delayed or denied, does that affect the all-source action plan? If reform is enacted, does the Company expect that would increase or decrease the amount of QFs for the years 2020 to 2023?

11. 2019 IRP Action Plan

In this section the Division provides comments on the Company's Action Plan under the Commission's Standards and Guidelines (the relevant Guideline, 4e, is in Appendix A). The Company provides its Action Plan in Table 1.5, beginning on p. 22 of Volume I of the IRP. There are six categories that comprise its 2019 IRP Action Plan:

1. Existing resource Actions: 1a, 1b, 1c, 1d, 1e
2. New resource Actions: 2a, 2b
3. Transmission Action Items: 3a, 3b, 3c, 3d, 3e, 3f, 3g
4. Demand-Side Management (DSM) Actions: 4a
5. Front Office Transactions: 5a
6. Renewable Energy Credit Actions: 6a, 6b

Of note in the 2019 IRP Action Plan, the Company is pursuing action items that deal with existing resource actions, most of which are related to early coal retirements, conversion of coal plants to gas plants, or as Section 2 of the Action Plan shows. A large amount of new resources will need to be added to account for the coal retirements, and renewables will fill most of the gap.

The Company included seven transmission action items, items 3a through 3g, in this portion of the IRP. Many different transmission actions have been grouped together, by general location. In fact, counting each bullet point in the Transmission Action Items, there are 27 transmission action items that need to be recognized and scrutinized in the Action Plan, not seven.

The 27 transmission action items in the Action Plan (Transmission Action Items: 3a through 3g) should not be specifically acknowledged. The transmission projects in the preferred portfolio are listed in Table 1.1 of the IRP, and Table 1.2 gives "the total amount of initial capital investment required to deliver incremental transmission and resource investments," for a total of $2,792 million or roughly \$2.8 billion.[55] In accordance with Commission Guidelines, these projects will be evaluated for prudence and necessity in the appropriate other dockets.

The Action Plan includes Action Item 3a, Gateway South, a 400-mile 500-kV transmission line from Aeolus substation in Wyoming to the Clover substation in Utah. The Company states that other Energy Gateway segments (Gateway West, Boardman to Hemingway) are beyond the scope of the current IRP, but that continued permitting for these projects is warranted.[56] Given the long lead times for the previously placed in-service segments of the Energy Gateway Projects, the Division finds that it is prudent to continue permitting the remaining Energy Gateway transmission projects.

Overall, the Division concludes that the Company followed the IRP Procedures and Guidelines in developing its Action Plan. The Division recommends that the Commission acknowledge the development of the Action Plan, without granting approval or acknowledgement of any particular item or assumption in the Action Plan.

- Division Recommendation: Overall, the Division concludes that the Company followed the IRP Procedures and Guidelines in developing its Action Plan. The Division does not recommend granting approval or acknowledgement of any particular item or assumptions in the Action Plan. As the Commission has stated in previous orders, the IRP docket is not the place where the costs and assumptions for specific projects are reviewed for prudence or necessity.

12. The Division's Findings and Recommendations to the Commission

The Division recommends that the Commission acknowledge that PacifiCorp's 2019 IRP largely adheres to the Commission's Standards and Guidelines. Taken as a whole the IRP should be acknowledged as being generally in compliance with the Commission's Standards and

[55] Docket No. 19-035-02, PacifiCorp's 2019 IRP, October 18, 2019, Vol. I, Table 1.2, p. 8.
[56] Id. at 71.

Guidelines. The Division recommends that the Commission take no action on PacifiCorp's 2019 IRP Action Plan, as the prudence review of specific items will take place in other dockets.

Cc: Michele Beck, OCS
Yvonne Hogle, PacifiCorp

Appendix A

IRP Procedural Issues

1. The Commission has the legal authority to promulgate Standards and Guidelines for integrated resource planning.

2. Information Exchange is the most reasonable method for developing and implementing integrated resource planning in Utah.

3. Prudence Reviews of new resource acquisitions will occur during ratemaking proceedings.

4. PacifiCorp's integrated resource planning process will be open to the public at all stages. The Commission, its staff, the Division, the Committee, appropriate Utah state agencies, and other interested parties can participate. The Commission will pursue a more active-directive role if deemed necessary, after formal review of the planning process.

5. Consideration of environmental externalities and attendant costs must be included in the integrated resource planning analysis.

6. The integrated resource plan must evaluate supply-side and demand-side resources on a consistent and comparable basis.

7. Avoided Cost should be determined in a manner consistent with the Company's Integrated Resource Plan.

8. The planning standards and guidelines must meet the needs of the Utah service area, but since coordination with other jurisdictions is important, must not ignore the rules governing the planning process already in place in other jurisdictions.

9. The Company's Strategic Business Plan must be directly related to its Integrated Resource Plan.

IRP Standards and Guidelines

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. The process should result in the selection of the optimal set of resources given the expected combination of costs, risk and uncertainty.
2. The Company will submit its Integrated Resource Plan biennially.
3. IRP will be developed in consultation with the Commission, its staff, the Division of Public Utilities, the Committee of Consumer Services, appropriate Utah state agencies and interested parties. PacifiCorp will provide ample opportunity for public input and information exchange during the development of its Plan.
4. PacifiCorp's future integrated resource plans will include: a. A range of estimates or forecasts of load growth, including both capacity (kW) and energy (kWh) requirements. i. The forecasts will be made by jurisdiction and by general class and will differentiate energy and capacity requirements. The Company will include in its forecasts all on- system loads and those off-system loads which they have a contractual obligation to fulfill. Non-firm off-system sales are uncertain and should not be explicitly incorporated into the load forecast that the utility then plans to meet. However, the Plan must have some analysis of the off-system sales market to assess the impacts such markets will have on risks associated with different acquisition strategies. ii Analyses of how various economic and demographic factors, including the prices of electricity and alternative energy sources, will affect the consumption of electric energy services, and how changes in the number, type and efficiency of end-uses will affect future loads. b. An evaluation of all present and future resources, including future market opportunities (both demand-side and supply side), on a consistent and comparable basis. i. An assessment of all technically feasible and cost- effective improvements in the efficient use of electricity, including load management and conservation.

ii An assessment of all technically feasible generating technologies including: renewable resources, cogeneration, power purchases from other sources, and the construction of thermal resources.

iii. The resource assessments should include: life expectancy of the resources, the recognition of whether the resource is replacing/adding capacity or energy, dispatchability, lead-time requirements, flexibility, efficiency of the resource and opportunities for customer participation.

c. An analysis of the role of competitive bidding for demand- side and supply-side resource acquisitions.

d. A 20-year planning horizon.

e. An action plan outlining the specific resource decisions intended to implement the integrated resource plan in a manner consistent with the Company's strategic business plan. The action plan will span a four-year horizon and will describe specific actions to be taken in the first two years and outline actions anticipated in the last two years. The action plan will include a status report of the specific actions contained in the previous action plan.

f. A plan of different resource acquisition paths for different economic circumstances with a decision mechanism to select among and modify these paths as the future unfolds.

g. An evaluation of the cost-effectiveness of the resource options from the perspectives of the utility and the different classes of ratepayers. In addition, a description of how social concerns might affect cost effectiveness estimates of resource options.

h. An evaluation of the financial, competitive, reliability, and operational risks associated with various resource options and how the action plan addresses these risks in the context of both the Business Plan and the 20-year Integrated. Resource Plan. The Company will identify who should bear such risk, the ratepayer or the stockholder.

i. Considerations permitting flexibility in the planning process so that the Company can take advantage of opportunities and can prevent the premature foreclosure of options.

j. An analysis of tradeoffs; for example, between such conditions of service as reliability and dispatchability and the acquisition of lowest cost resources.

k. A range, rather than attempts at precise quantification, of estimated external costs which may be intangible, in order to show how explicit consideration of them might affect selection of resource options. The Company will attempt to quantify the magnitude

of the externalities, for example, in terms of the amount of emissions released and dollar estimates of the costs of such externalities. l. A narrative describing how current rate design is consistent with the Company's integrated resource planning goals and how changes in rate design might facilitate integrated resource planning objectives.
5. PacifiCorp will submit its IRP for public comment, review and acknowledgement.
6. The public, state agencies and other interested parties will have the opportunity to make formal comment to the Commission on the adequacy of the Plan. The Commission will review the Plan for adherence to the principles stated herein, and will judge the merit and applicability of the public comment. If the Plan needs further work the Commission will return it to the Company with comments and suggestions for change. This process should lead more quickly to the Commission's acknowledgement of an acceptable Integrated Resource Plan. The Company will give an oral presentation of its report to the Commission and all interested public parties. Formal hearings on the acknowledgement of the Integrated Resource Plan might be appropriate but are not required.
7. Acknowledgement of an acceptable Plan will not guarantee favorable ratemaking treatment of future resource acquisitions.
8. The Integrated Resource Plan will be used in rate cases to evaluate the performance of the utility and to review avoided cost calculations.