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DIVISION COMMENTS ON PACIFICORP'S 2015 IRP

To: Utah Public Service Commission

From: Division of Public Utilities
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Date: August 25, 2015

Subject: Docket No. 15-035-04, PacifiCorp's 2015 Integrated Resource Plan

RECOMMENDATION (ACKNOWLEDGE)

The Division of Public Utilities (Division) recommends that the Public Service Commission (Commission) acknowledge PacifiCorp's 2015 Integrated Resource Plan (IRP) and Action Plan. As explained below, the Division finds the 2015 IRP sufficiently complies with the Standards and Guidelines and meets the directives from the Commission's January 2, 2014 IRP Order.[1]

BACKGROUND

On March 31, 2015, PacifiCorp (Company) filed its 2015 IRP pursuant to the Commission's 1992 Report and Order on Standards and Guidelines for Integrated Resource Planning in Docket No. 90-2035-01. The Company requests that the Commission acknowledge the 2015 IRP in

1 Docket No. 13-2035-01, Report and Order, January 2, 2014.

accordance with its rules and fully support the 2015 IRP conclusions, including the proposed Action Plan.[2] In addition, the Company requests that the Commission acknowledge the Wallula to McNary transmission project, a thirty-mile 230 kilovolt (kv) transmission line between Washington and Oregon that represents a portion of Segment A of the Company's Energy Gateway transmission project.[3]

On April 16, 2015, the Commission convened a Scheduling Conference that resulted in the Commission's April 17 Scheduling Order and Notice of Technical Conferences in this matter. The Commission held a Technical Conference on June 22, 2015--a public session in the morning that was a high level overview of Volumes I and II and a confidential afternoon session in the afternoon focusing on Volume III of the 2015 IRP. The Commission convened an additional Technical Conference on July 17, 2015, for the purpose of discussing Demand Side Management (DSM) issues related to the 2015 IRP. In addition to IRP comments to be filed by interested parties on or before August 25, 2015, the Commission requests comments on the Company's Resource Potential Assessment for 2015 through 2034 that was filed concurrently with the 2015 IRP.

In response to the Commission's request for comments, the Division provides the following IRP comments, with a focus on whether the 2015 IRP complies with the Commission's 1990 Standards and Guidelines and more recent Commission IRP orders. The Division's comments are organized as follows: (1) General Comments on the 2015 IRP, (2) Actions from the Commission's 2013 IRP Order, (3) Review of Load Growth and Resource Deficit, (4) Comments on DSM Resources, (5) Adequacy of the IRP and IRP Action Plan, (6) Summary and Recommendations, and (7) Conclusion.

[2] PacifiCorp's 2015 IRP Cover Letter, March 31, 2015.
[3] PacifiCorp's 2015 IRP, Volume 1, Chapter 4, p. 49.

GENERAL COMMENTS ON THE 2015 IRP

The Division recognizes the difficult task of developing this IRP in a time of flux and uncertainty, and it commends the Company for its efforts to adapt to change and anticipated environmental regulations. The Company has welcomed and responded to stakeholder input throughout the 2015 IRP process. The Division appreciates the Company's willingness to receive and consider its suggestions for continued refinements to the process. The Division has participated in this biennial cycle of the IRP process as an active and engaged stakeholder and recognizes and commends the Company for the steps it has implemented to improve the IRP public process. Given the intricacies of resource planning for a utility operating in six states, five with its own IRP guidelines or other long-term planning requirements, the Division appreciates the hard work and creativity of Rick Link and his staff for the effective management of the IRP process for the Company as it attempted to deal with the Clean Power Plan, the 111(d) requirements, and other emerging regulations and technologies.

The Company acknowledged the divergent opinions and priorities among stakeholders, as well as the variation in what the IRP means among different states. The Company's goal for the 2015 IRP was "to be responsive to all stakeholders and all requests; however, it is often not practical or possible to accommodate all requests."[4]

The Division believes that the Company could go one step further in improvement by having the vendors or consultants in attendance either on the telephone or in-person to discuss outside or supplemental studies on the date that the respective study is being presented. There were 10 supplemental studies in the 2015 IRP, some of which were covered well. Others were rushed through or barely discussed (usually due to the fact that there were too many items on the agenda to get through the details). A quick slide or two cannot fully capture the depth of the some of the studies, and at times the Company could not respond to specific questions with respect to the study. More depth and more time should be allowed to cover supplemental studies or reports

[4] PacifiCorp's June 5, 2015 Kick-Off Meeting, slide 8.

that are conducted outside the IRP modeling, but that are brought into the IRP process. The Division requests that the Company explain further to the larger stakeholder group about all state-specific programs or reports that affect the IRP or that go into IRP assumptions, such as those that come from the Energy Trust of Oregon and the Northwest Power Pool and Council. The Division recognizes that this may require additional meetings, but believes the studies are important inputs driving the IRP, and as all other inputs, affect the results of the IRP modeling.

As in the past, the Company's 2015 IRP evaluates a 20-year study period, but focuses on the first ten years (2015- 2024) in its assessment of resource need. Broken down into three parts, Volume I includes the main body of the plan. Volume II holds the appendices, and confidential Volume III includes an in-depth coal plant analysis. The Division, as well as other parties, has provided informal comments to the Company throughout the cycle of the IRP in the form of questions, verbal comments, and written comments.

According to the 2015 IRP, for the first 10 years of the 20-year IRP planning horizon, accumulated acquisition of incremental energy efficiency resources meets 86 percent of forecast load growth from 2015 through 2024 across the utility's six-state service territory. The Company plans to retire much of its coal fleet beginning with the closure of the Carbon plant in 2015, repowering to natural gas the Naughton 3 unit in 2018, either the early retirement or coal-to-gas conversion of Cholla 4 in 2025. The remaining coal plants are designated for early retirement at various times after 2025. The Company believes that its resource needs can be met with DSM and firm market purchases alone until 2028 when the first thermal resource is added.

To control carbon emissions, the IRP's preferred portfolio calls for allocating system renewable generation among states, acquiring energy efficiency resources and re-dispatching fossil-fired generation. Regional haze limits support converting coal-fired Naughton Unit 3 to burn natural gas in 2018, and the IRP includes strategies that avoid installation of selective catalytic reduction emissions control equipment at Wyodak, Dave Johnston Unit 3, and Cholla Unit 4.

Although not perfect, the Company came up with a reasonable preferred portfolio of resources that meets what it believes are known or anticipated environmental regulations as well as state IRP requirements. The Division finds that the preferred portfolio, Case C05a-3Q, is one of a possible universe of approximately least cost, least risk portfolio combinations that meets the draft 111(d) rule,[5] regional haze requirements, and all other state regulatory requirements for this IRP. Given the fact that President Obama directed the Environmental Protection Agency (EPA) to issue a proposed final rule in 2015 to regulate carbon pollution from existing power plants under section 111(d) of the Clean Air Act, and the IRP was filed on March 31, 2015 (approximately four months before the final rule was filed), the Division deems the 2015 IRP preferred portfolio and Action Plan are as reasonable as can be expected and recommends they both be acknowledged.

ACTIONS FROM THE COMMISSION'S 2013 IRP ORDER

The following discussion lists items from the Commission's 2013 IRP Order[6] that the Commission either ordered, encouraged, or suggested be addressed in the Company's 2015 IRP. Each action quotes the Commission's Order, followed by the Division's notes on whether this item was adequately addressed in the 2015 IRP.

1. Coal Plant Investment Analysis

> Because EPA's proposed and final implementation plans and challenges to those implementation plans continue to fluctuate, we encourage PacifiCorp to continue to monitor and prudently respond to the constantly changing landscape in its IRP update to be filed in 2014 ("2013 IRP Update") and in the 2015 IRP. (p. 14)

An analytical challenge of the 2015 IRP was to develop a planning framework to address the cost, risk, and uncertainty associated with the anticipated EPA proposed rule to regulate carbon dioxide emissions under §111(d) of the Clean Air Act. The Company responded with its 111(d)

[5] 1) The final rule under § 111(d) of the Clean Air Act was published on August 3, 2015; 2) is significantly different from the draft rule issued in June 2014; and 3) will be analyzed going forward.
[6] Docket No. 13-2035-01, Report and Order, January 2, 2014.

Scenario Maker, which calculates an annual 111(d) emission rate for Utah, Oregon, Wyoming, and Washington and then calculates a compliance action that can be implemented where needed. The Company used three 111(d) compliance strategies among two different emission rate policy definitions, assuming it must comply with the EPA's draft 111(d) rule, as well as other regional haze rules. The Company assumed that emission control retrofit decisions would need to be made within the 2015 IRP Action Plan time frame. The Company's inter-temporal and fleet-trade off compliance alternatives evaluated were developed to represent potential scenarios that might, pending agency support, achieve the appropriate balance of economic and emission reduction balance.[7]

The Division finds that the Company has monitored and responded to the EPA proposed and final implementation plans. The EPA's rule 111(d) was a key driver in the 2015 IRP, along with the load forecast. Because EPA's proposed and final implementation plans and legal and political challenges to those implementation plans continue to fluctuate, the Company plans to continue to monitor and plan to the changing landscape in its IRP update and in its 2017 IRP.

2. Energy Gateway Transmission Analysis

> PacifiCorp should continue to discuss with state agencies and other interested parties how best to consider this information in the identification of a preferred portfolio prior to its use. A key objective should be to provide transparency when comparing the cost, risk and performance of portfolios both with and without such non-modeled costs or benefits. At a minimum, any preferred portfolio selection that includes non-modeled benefits should be subject to stochastic risk analysis for the determination of risk and other performance metrics. (p. 15)

The company formed a System Operational and Reliability Benefits Tool (SBT) stakeholder group to discuss refining the SBT that was used in the Energy Gateway transmission analysis in the 2013 IRP. The Division participated in three stakeholder workshops on July 29, 2014, August 26, 2014, and September 17, 2014. The Division finds that the Company has met this

[7] Docket No. 15-035-04, PacifiCorp's 2015 Integrated Resource Plan, Volume III, p. 1.

objective, because it did have a SBT discussion. A SBT analysis was not relied on for transmission projects in the 2015 IRP. However, as the Company continues to permit sub-segments of Energy Gateway Section D, E, and F, the Division foresees that in future IRPs, the SBT will be used again. Prior to that time, the Division recommends the Company hold an entire meeting devoted to the SBT for all stakeholders, so that the SBT can continue to be refined and vetted before the larger IRP stakeholder group. Any project that goes through the SBT in future IRPs needs to be subjected to stochastic risk analysis to determine risk and other performance metrics. Slides from the SBT stakeholder group indicated that parties had several questions and concerns.[8]

The Company continues transmission planning efforts for segments of Energy Gateway West, Energy Gateway South, and Boardman to Hemingway. In the 2015 IRP the Company requests acknowledgement of its plan to construct the Wallula to McNary portion of the Walla Walla to McNary transmission project. (Segment A). The Company provided supporting documentation for the need of this segment, which showed that the line is required to satisfy its regulatory obligation to serve network transmission customers under its Open Access Transmission Tariff (OATT). The Wallula to McNary transmission line is a 230 kV, single circuit line that is 30 miles long. The Division has reviewed the majority of the supporting documentation that it requested in formal data requests.[9] Without the transmission line, the Company states that it has no available capacity to serve transmission customers requesting service on the existing Wallula to McNary transmission line. The Company states that it has obtained a Certificate of Public Convenience and Necessity (CPCN) from the Oregon Public Utility Commission.[10]

The Division recommends the Commission acknowledge this segment of the Energy Gateway project with the caveat that acknowledgement does not guarantee favorable ratemaking treatment or a presumption that the costs are prudent when they are brought forward in a general rate case

[8] These slides can be found at the following link: http://www.pacificorp.com/content/dam/pacificorp/doc/Energy_Sources/Integrated_Resource_Plan/SBT/PacifiCorp-SBT_WorkshopNo3-11-20-2013.pdf.
[9] Company's Response to DPU 3.6 through 3.15, May 7, 2015.
[10] Docket No. 15-035-04, PacifiCorp's 2015 Integrated Resource Plan, Volume I, p. 49.

proceeding. The Division also notes the Company entered into the California Independent System Operator (CAISO) energy imbalance market (EIM) to bring more efficient dispatch to the Company's balancing authority areas.

On another transmission-related note, the Division points out that, due to the Federal Energy Regulatory Commission's (FERC) Order No. 1000 requirements for cost allocation and inter-regional planning, the Company should explain in its 2015 IRP Update and 2017 IRP how and where this will affect the Company's Energy Gateway plans and future IRPs. According to FERC Order No. 1000, any new transmission project will have to go through planning and cost allocation. Although not required in the 2015 IRP, the Division requests that the Company explain how the FERC Order 1000 requirements will come into play in the context of the Company's future IRPs.

3. Wind and Solar Resource Costs

> As we have stated in the past, sensitivity analysis should be an effective tool for evaluating the effect on resource selection of various assumptions regarding solar and wind resource costs. We recognize there are differences of opinion, and some uncertainties, regarding renewable resource cost assumptions. We encourage PacifiCorp and stakeholders to develop a strategy to address this issue in the 2015 IRP. Further, the results of this effort could be utilized in PacifiCorp's acquisition path analysis to inform decisions if the future unfolds differently than expected. (p. 17)

PacifiCorp developed a strategy in this IRP to solicit feedback from stakeholders through an online stakeholder feedback form. This is in addition to feedback received at public stakeholder meetings. The Company reviewed the solar and wind resource cost assumptions at the August 7, 2014 public meeting, where the Company also solicited feedback and updated its resource cost assumptions. As a result of stakeholder feedback, the Company performed a sensitivity analysis around the potential stakeholder-submitted costs of future solar resources (Case S-12).

4. Market Constraints

> The Office recommends the Commission require PacifiCorp "to provide a contingency plan for the IRP's heavy reliance on [front office transactions] to be used in the event that market supplies tighten and prices increase significantly. This contingency plan should be provided as part of the 2013 IRP Update and addressed more fully in the next IRP cycle." We encourage PacifiCorp to examine the Office's recommendation in the 2015 IRP cycle. Such analysis could be included in the section of the IRP devoted to acquisition path analysis. (p. 22)

The Company did not provide a contingency plan, but rather reduced its reliance on front office transactions (FOTs) in the 2015 IRP. This was, according to the Company, a result of decreased load, increased distributed generation (DG) penetration, and increased DSM acquisition.[11] In the 2015 IRP preferred portfolio FOTs have decreased by 29 percent through 2024 compared to the 2013 IRP preferred portfolio. The Company calculated core cost definitions that include a scenario that limits market purchases at the Northern California (NOB) and Mona trading hubs as part of an acquisition path analysis.

Taken together the Division determines that the Company has met this guidance principle in its 2015 IRP, but recognizes a continued need to monitor market constraints. The Division recommends that the Commission require future IRPs to present a contingency plan or demonstrate that there is sufficient market liquidity and depth in PacifiCorp's service territory in the event the market supplies tighten and prices increase significantly. In light of the fact that the 2015 IRP does not include a baseload gas generation resource until the year 2028 and the fact that the Company is also relying heavily on energy efficiency resources, the Division believes this recommendation is an important one. The Division believes that the purpose of long-term resource planning is to make sure that the required resources are available as the future unfolds.

5. Planning Reserve

> We accept a 13 percent planning reserve as reasonable for this IRP and recommend continued analysis of this issue, both through LOLP study and tradeoff analysis. (p. 23)

[11]Id. at Volume II, p. 32.

PacifiCorp performed a planning reserve margin (PRM) study, where it evaluated the relationship between cost and reliability. The results showed that with a 13 percent PRM level, the Company can reliability meet load while maintaining operating reserves, with a planning criteria that meets the "one day in 10 year" planning target at the lowest reasonable cost. The Division recommends the Commission require the Company to continue to analyze the PRM in its 2017 IRP.

6. Load Forecasting

> We direct PacifiCorp to present in the 2015 IRP an analysis of whether the available historical cooling degree day information is an appropriate predictor of future "normal" conditions and, if warranted, to identify and implement a superior predictor in that IRP. (pp. 23-24)
>
> We direct PacifiCorp to facilitate a discussion of this issue in the 2015 IRP cycle. (The issue is PacifiCorp's decision to eliminate the long-run load volatility parameter from its stochastic analysis.) (p. 24)

The Company eliminated the long-run load volatility parameter from its stochastic analysis in its 2013 IRP. The Division confirms that the Company discussed this issue in the stochastic parameter meetings on August 7-8, 2014 and September 25-26, 2014 public stakeholder meetings. Therefore, the Company met the discussion criteria.

The larger part of this condition directs the Company to present an analysis in the 2015 IRP of this issue. The Company argued that it is more appropriate to study long-term load risk through load forecast scenario analysis and therefore in the 2015 IRP continued its use of short-term volatility and mean reversion parameters to model load volatility. The Company performed a load sensitivity analysis that supports the use of short-term volatility and mean reversion parameters to model load volatility (Case S-03). The sensitivity results are presented in Volume I, Chapter 8.

7. Stochastic Risk Modeling Workshop

> We suggest PacifiCorp include this topic (stochastic risk modeling) in a separate workshop in its 2015 IRP cycle. Topics for discussion should include how forced outages and load volatility are modeled. (p. 25)

Stochastic risk modeling was discussed, among other topics, on August 8, 2014 (slide 67) and on January 29, 2015 (slides 41-50) at the public stakeholder meetings. The load volatility issue was mentioned in the previous section on load forecasting. At the August 8, 2014 workshop, the Company described how cost and risk analysis is performed through a multi-level process. System Optimizer is used to identify unique resource portfolios. Stochastic risk modeling is then used to further define those portfolios using Planning and Risk (PaR) analysis. The Company uses stochastic Monte Carlo simulations for PaR analysis, as found in Volume II, Appendix H of the 2015 IRP. The Company performs stochastic risk modeling of load, price, hydro generation availability, and thermal outages for new thermal plants in PaR. Additionally, the Company uses econometric modeling techniques to further define selected portfolio risk analysis in greater detail than prior IRP cycles. Out of the top performing resource portfolios, deterministic risk modeling is used to study those portfolios under different scenarios not used initially. At the Company's September 25, 2014 workshop, the stochastic scope, PaR scenarios, and stochastic portfolio measures were discussed. Appendix R contains the details of how methodologies are determined, as well as how stochastic parameters are developed. The Division believes the Company complied with this requirement of the Commission's Order.

8. Robust Portfolio Identification

> We concur with the Division this is a very useful table and we encourage PacifiCorp to expand its use of (Table 9.2) in its 2013 IRP Update and 2015 IRP to address additional issues. For example, changes to resource costs, power market availability, and environmental regulations could be addressed through this table. This will allow the IRP to be more useful, flexible, and transparent between the filing of IRPs. (p. 24)
>
> PacifiCorp should discuss with stakeholders which issues should be studied for inclusion in this table. (p. 25)

> We encourage PacifiCorp to work with stakeholders in the 2015 IRP cycle to ensure cases of interest to stakeholders, including sensitivity cases, are fully evaluated against cost, risk and performance measures. (p. 26)
>
> We encourage PacifiCorp to engage stakeholders in developing scenarios to address and update key uncertainties. (p. 27)

The Division believes the Company did a commendable task of expanding the resource acquisition path table in the 2015 IRP, as the Commission encouraged. The 2013 acquisition path analysis focused on load trigger events, combinations of environmental policies, and market price trigger events.[12] In the Company's 2013 IRP Table 9.2 – Near-term and Long-term Resource Acquisition Paths, the Company identified only four triggering events.[13] In the 2015 IRP, the Company included 10 triggering events, which required alternative near-term and long-term resource acquisition strategies.[14] In the 2015 IRP, triggering events include: load growth, potential 111(d) policy outcomes, compliance outcomes related to future Regional Haze requirements, Renewable Portfolio Standard (RPS) compliance obligations, and DSM acquisition strategies. The Company solicited both oral and written stakeholder feedback with respect to this table. The Company met this requirement, and the Division encourages the Company to continue developing its acquisition path analysis and possibly address other trigger events as the future unfolds.

The 2015 IRP cycle was open, transparent, and engaging. The Division notes that the Company made many improvements to the process, including providing data disks of all tables and IRP assumptions. Unfortunately, the Division was unable to open most of the files on the disk. The Division recommends that the Company provide instructions on how to open the files or convert them to Excel or other file formats that are usable. As previously mentioned, the Company developed a Stakeholder Feedback Form to solicit comments from stakeholders and was

[12] Docket No. 13-2035-01, PacifiCorp's 2013 Integrated Resource Plan, Volume I, April 31, 2013, p. 265.
[13] Id. at pp. 32-33.
[14] Docket No. 15-035-04, PacifiCorp's 2015 Integrated Resource Plan, Volume I, March 31, 2015, pp. 237-238.

responsive to stakeholder comments. The Company included sensitivity studies influenced by stakeholders, as well as renewable resource costs and various other topics.

9. Demand Side Resource Acquisitions

> We agree the significant reliance on DSM needs to be closely monitored. We concur with the Office that expected capacity contribution to IRP DSM capacity goals should be provided in any application for DSM program approval. (p. 29)

The Division has closely monitored the DSM capacity goals in the 2015 IRP and reports that the Company has provided the expected capacity contribution to IRP capacity goals in its Energy Efficiency and Peak Reduction Report filed with the Commission each year. The Division finds that the Company has met this requirement. The Division provides additional comments later in this report in the section titled "Comments on DSM Resources."

10. Link to Business Plan

> We note PacifiCorp did not present the Business Plan as a sensitivity case in the 2013 IRP. We remind PacifiCorp to provide this sensitivity in the 2013 IRP Update and all future IRPs. (p. 30)

The Company did not use the Business Plan as a sensitivity case in the 2015 IRP. This was based on a discussion and understanding agreed to at the July 18, 2014 public stakeholder meeting. Mr. John Harvey of the Commission staff clarified that the link to the Business Plan could be met through the acquisition path analysis. The Company notes "that resource changes and changes in resource procurement strategies driven by changes in the planning environment are captured in the IRP and future business plan cycles."[15]

The Division analyzed the link of the 2015 IRP to the Business Plan, as well as how previous IRPs were linked or aligned to the Business Plan. The Commission's Standards and Guidelines (No. 9) states that the Company's Strategic Business Plan must be directly related to its Integrated Resource Plan.[16] In order to make this determination, the Division first reviewed the

[15] Id. at p. 33.
[16] Docket No. 90-2035-01, Report and Order, June 18, 1992, p. 19.

Company's fall 2014 Business Plan at the Company's offices, but could not verify the assumptions or how the results were derived.[17] In the 2015 IRP, the Company puts forth a comparison of the 2015 IRP versus the fall 2014 Ten-Year Business Plan.[18] The Company explains the differences between the two portfolios as being driven by reduced loads and updated DSM supply curve assumptions. The Division notes that the Business Plan had on average 1,227 megawatts of front office transactions, as compared to the average 843 megawatts in the 2015 Preferred Portfolio. The 2015 IRP had significantly more DSM resources—1,429 megawatts of energy efficiency-- as compared to 815 megawatts in the Business Plan. As the Division commented previously, this is a significant increase in energy efficiency, and the Division hopes the Company can achieve this level. Company officials approve the Business Plan in December of each year. Therefore, the March 31, 2015 IRP should not vary substantially in three months without further explanation or without considering the variations where significant. The Commission's Report and Order on Standards and Guidelines also states that "consistency between the Company's strategic business plan and its IRP is necessary to ensure that ratepayers receive the benefits from the IRP."[19]

The 2015 IRP Action Plan states that "the 2015 IRP preferred portfolio will serve as the starting point for resource assumptions in the fall 2015 ten-year business plan."[20] This assumption, together with the Company's acquisition path analysis,[21] satisfies this requirement.

REVIEW OF LOAD GROWTH AND RESOURCE DEFICIT

Generally, the Company forecasts loads by state and then by class of service, i.e. by residential, commercial, and industrial (and a small "other," which is primarily street lighting). It uses different statistical methods and surveys that are customized to a particular state and customer. For large industrial customers, the forecasts are primarily based upon Company representatives'

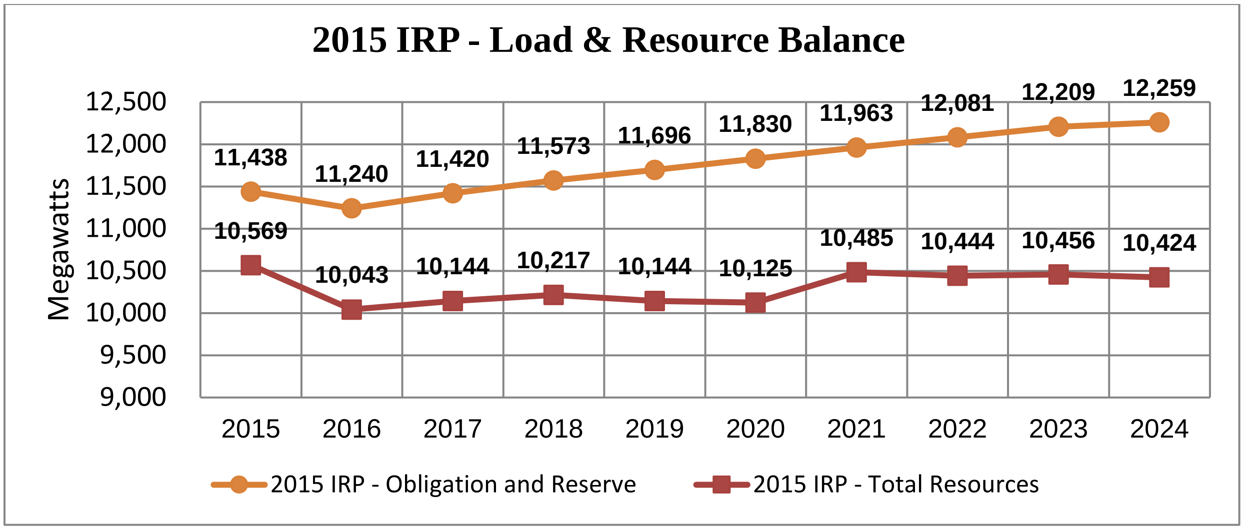
[17] Company's Response to DPU data request #3.2. The Division reviewed the Business Plan on May 18, 2015.
[18] Docket No. 15-035-04, PacifiCorp's 2015 Integrated Resource Plan, Volume I, pp. 241-242.
[19] Report and Order on Standards and Guidelines, Docket No. 90-2035-01, June 18, 1992, p. 17.
[20] Docket No. 15-035-04, PacifiCorp's 2015 Integrated Resource Plan, Volume I, p. 213.
[21] Id. at pp. 265-266.

direct discussions with those customers about their expected electric needs, as well as information from media and various sources about new large industrials coming into an area. The load forecasting process is lengthy and appears to be reasonably sophisticated. In the near term, i.e. one to three years out, the Company is able to modify its overall statistical forecasts with known load additions (or subtractions), such as the buildup of call and data centers in certain areas.

The Division analyzed the load and resource balance for the 2015 IRP prepared by the Company. The load and resource balance in the 2015 IRP is based on a load forecast as of September 2014. 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 has been developed from information provided by the individual customer.

Utah customers account for approximately 43 percent of the forecast load and represent the largest increase to the system. The forecast annual load growth in Utah is projected to be 1.78 percent compared to the total system load growth of 0.85 percent.[22] The projected growth in Utah is nearly twice the growth rate of the total system and is consistent with prior IRP filings. The chart below provides a summary of the projected load and resource balance for the entire PacifiCorp system.

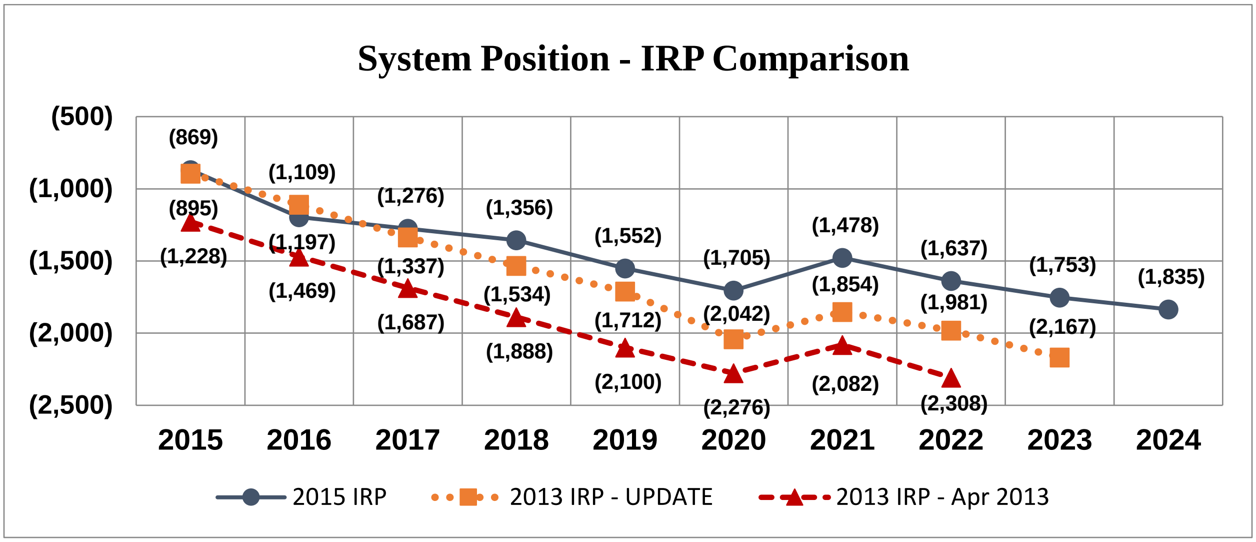
[22]Id. at Volume II, p. 81.



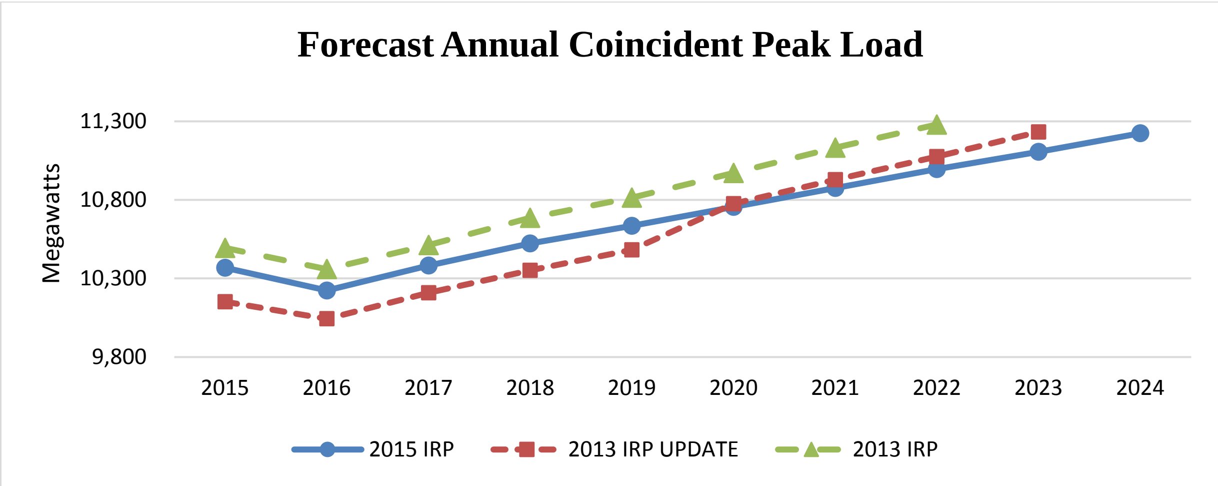
The reduction in the resources in 2016 is due to the expiration of the Hermiston Power Purchase Agreement, and the increase in resources in 2021 is due to a change in the forecasted sale category. For all of the years under review, the obligation or system requirement is greater than the available resources. With an increasing gap between the total obligation and total resources, the Company relies more heavily on FOTs to satisfy the difference. The reliance on FOT transactions continues to be a concern to the Division and to other Utah parties. This reliance on the wholesale electric market could result in ratepayers facing greater price volatility and potentially loss of power except at very high prices in the event that the wholesale markets dry up due to environmental concerns and the possible closure of existing coal fired generation facilities, among other reasons.

In comparison to the 2013 IRP Update, the 2015 IRP projects additional resources from renewables, Qualifying Facilities, and Class 1 DSM. PacifiCorp has also modeled Class 2 DSM as a resource option to be selected as part of the cost-effective portfolio resource mix. The changes to the modeling increase the total resource and the total obligation requirement for all years under review.

The total obligation less the total resources produces the system net position. A comparison of the system net position in the last three IRP filings has been included in the chart below.[23]



The change in each IRP shows how more certainty is built into the forecast as the Company moves closer to the actual delivery date.



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[23] Id.

The system coincident peak load is the annual maximum hourly load on the system. The Division compared the system coincident peak load forecast for the current and past two IRPs for the years 2015 through 2034.[24] The results trend similarly, but after 2020, the 2015 IRP forecasts lower system coincident peak than the 2013 IRP Update and the 2013 IRP. Based upon the foregoing discussion the Division believes the Company's load forecast out to 2024 is reasonable. The projected load growth across the Company's service territory has flattened and thus has not been as much of a pressing issue in this IRP. In the 2015 IRP, the complexities of the environmental regulations represented the overarching planning issue in this IRP.

COMMENTS ON DSM RESOURCES

The Company's Demand-Side Resource Potential Assessment (DSM potential study) for 2015 through 2034 was prepared by Applied Energy Group (AEG), a different consultant than the prior two studies.[25] The Company states that the AEG study is an update of previous studies. The DSM potential study tries to assess the available potential and the associated cost of Class 1, 2, and 3 DSM potential in each of the Company's six states. The DSM potential study is updated every two years to reflect changes in load forecasts, available data sources, measures, codes and standards, economic assumptions, etc. The Company and the Energy Trust of Oregon staff coordinate on key Class 2 DSM assumptions, such as measure lists, administrative costs, levelized cost calculations, treatment of non-energy benefits, etc.

The study looks at state-specific assessments of opportunities in all major sections and market segments. The study first looks at all technically potential Class 2 DSM, then filters out the achievable technical potential that is provided for the IRP System Optimizer model, which is the share of technical potential that might reasonably be achievable over the planning period, given market barriers possibly impeding customer adoption. The IRP model then selects the

[24] Id. at Volume II, p. 3.
[25] The Cadmus Group had conducted the study for the 2011 IRP and the 2013 IRP.

achievable economic potential, or the portion of achievable technical potential deemed cost-effective by the IRP model. New to the 2015 IRP is a section on state implementation plans for each state, per an Oregon regulatory requirement.

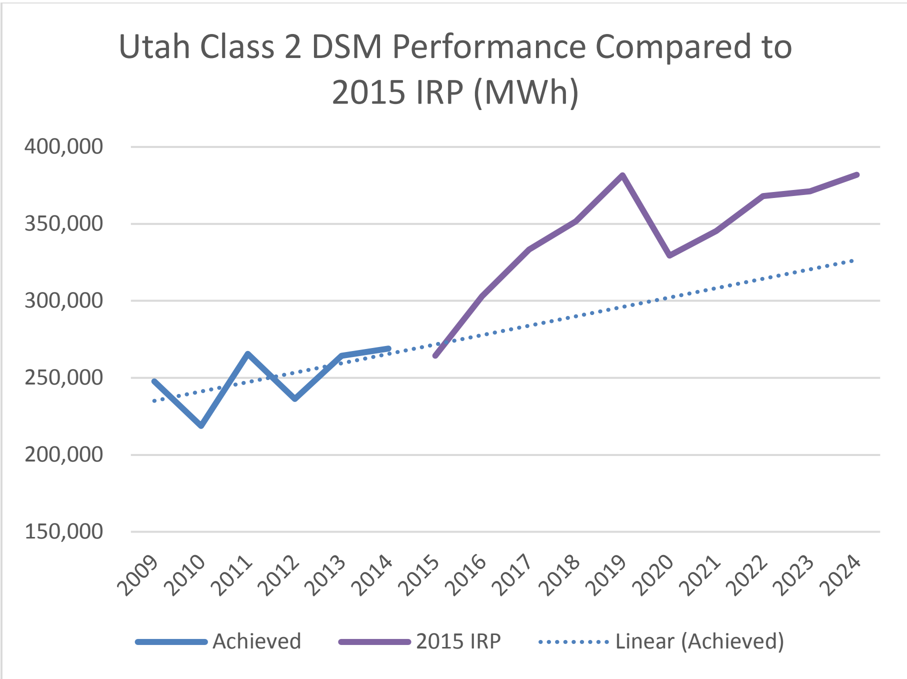
The results from the study are incorporated into PacifiCorp's 2015 IRP, and the DSM resources are treated in the same manner as supply-side resources. DSM resources are selected on an economic basis in the System Optimizer model based on location and characteristics and treated as must-run resource in the PaR model. The 2015 IRP preferred portfolio indicates that PacifiCorp's resource needs can be met with DSM and short-term firm market purchases through 2027.[26]

The Division appreciates and supports the Company's efforts in its pursuit of cost effective DSM resources and believes DSM can effectively offset a portion of Utah's increasing load. However, the Division is concerned that the 2015 IRP preferred portfolio for Class 2 DSM may be overly aggressive and therefore, may not be achievable. For example, the 2013 IRP preferred portfolio included 63 megawatts and 61 megawatts of Utah Class 2 DSM for the years 2013 and 2014, respectively. The 2013 DSM Annual Report stated that in 2013, only 58.8 megawatts of the forecasted 63 megawatts were achieved.[27] In the 2014 DSM Annual Report, only 45 megawatts of the forecasted 61 megawatts were actually achieved in Utah.[28] The Commission stated clearly in its 2013 IRP Order that a significant reliance on DSM resources needs to be closely monitored. The Division has been monitoring the DSM resources and notes that the actual achievable DSM resources are not meeting the IRP targeted DSM resources.

The Company is relying heavily on Class 2 DSM in the 2015 preferred portfolio, with the 2015 IRP estimate of accumulated acquisition of Class 2 DSM at 86 percent of forecast load growth over the next ten years. This is up from the 2013 IRP where Class 2 DSM estimates were at 50

[26] Id. at Volume I, p. 189.
[27] 2013 Utah Energy Efficiency and Peak Reduction Annual Report, May 16, 2014, Docket No. 14-035-50.
[28] 2014 Utah Energy Efficiency and Peak Reduction Annual Report, May 1, 2015, Docket No. 15-035-50.

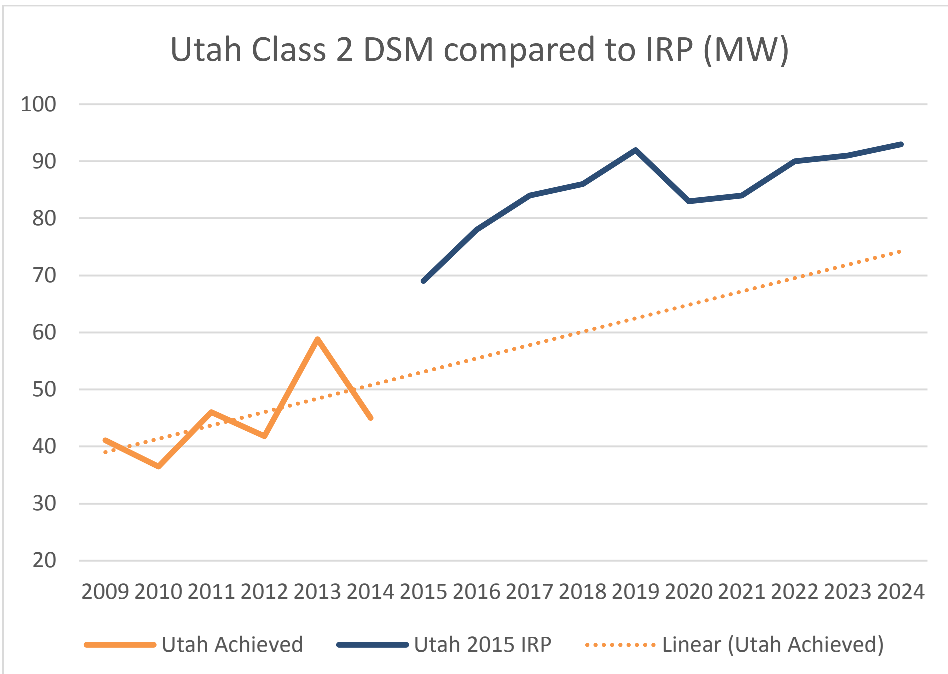
percent of planned, new long-term resources. Class 2 DSM was unable to achieve the 2013 IRP estimate that was considerably lower than what is modeled in the 2015 IRP preferred portfolio. The chart below provides the estimated performance of Utah Class 2 DSM, in megawatt hours, for the 2015 IRP preferred portfolio for the first ten years of the planning cycle (2015 through 2024). The chart also contains the actual performance of the estimated Utah Class 2 DSM megawatt hours achieved for the periods 2009 through 2014.[29]



The above graph also contains a trend line, based on actual Class 2 DSM performance for 2009 through 2014, of the estimated achieved Class 2 DSM resources that could be reached for the years 2015 through 2024.

[29] Docket No. 15-035-04, PacifiCorp's Integrated Resource Plan, Volume II, p. 64.
2014 Utah Energy Efficiency and Peak Reduction Annual Report, May 1, 2015, Docket No. 15-035-50.
2013 Utah Energy Efficiency and Peak Reduction Annual Report, May 16, 2014, Docket No. 14-035-50.
2012 Utah Energy Efficiency and Peak Reduction Annual Report, May 1, 2013, Docket No. 13-035-71.
2011 Annual Energy Efficiency and Peak Reduction Report – Utah, April, 27, 2012, Docket No. 12-035-57
2010 Annual Energy Efficiency and Peak Reduction Report – Utah, April 7, 2011, Docket No. 11-035-74.
2009 Demand-Side Management Annual Report for 2009 – Utah, March 31, 2010, Docket No. 10-035-27.

The 2015 IRP Class 2 DSM increases significantly from what the trend line suggests is achievable, based on the past performance of DSM in Utah. Even with the forecasted downturn in 2020, the Class 2 DSM resources in the 2015 IRP maintains a markedly higher level than the estimated achieved trend line.



The chart above indicates that the trend line for the Utah achieved megawatts is considerably less than the 2015 IRP Utah Class 2 DSM estimate. If the estimated DSM is not achieved, then the Company may be compelled to rely on even more FOTs that may put customers at risk for higher prices.

In addition to achieving what is the technical potential with respect to Class 2 DSM, the Division has concerns regarding costs that may be prohibitive. The March 31, 2015 IRP filing contains the preliminary IRP DSM portfolio budget based on existing offerings and planned activities for 2015 through 2018. The Company provided an updated IRP DSM budget at the July 17, 2015

IRP Technical Conference, which shows that additional costs may be required to achieve the Class 2 IRP targets. The table below compares the preliminary budget to the updated budget.

DSM Portfolio Budget ($ Million)					
	2015	**2016**	**2017**	**2018**	**Total**
2015 IRP Portfolio Budget[30]	$60	$65	$64	$74	$263
DSM Estimated Budget[31]	$64	$68	$80	$86	$297

The variability of incentive and administrative costs create uncertainty in the budget forecast. The increase in costs may also cause the preferred portfolio to lose its attractiveness.

Many stakeholder comments and feedback convey the conviction that more DSM should be included in the IRP and push the Company to accelerate the acquisition of DSM in the IRP. However, as the Division has demonstrated, if the targets are unachievable and the costs are not economic, the IRP has overstated its DSM targets. The Division recommends that the Commission direct the Company that the DSM targets need to be both technically and economically achievable in future IRPs in order for the preferred portfolio to remain the least cost, least-risk option. The Division believes it would be helpful if the Company's DSM department work collaboratively with its IRP team in evaluating the DSM Potential Study results to see if the DSM department believes the DSM targets are economical and technically achievable in Utah before selecting the 2017 IRP Preferred Portfolio. The Division also recommends that the Company hold a separate technical conference in the 2017 cycle that includes the IRP department and the DSM department, as was done this year.

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[30]Docket No. 15-035-04, PacifiCorp's 2015 Integrated Resource Plan, Volume II, p. 69.
[31] 2015 IRP DSM Technical Conference, July 17, 2015.

ADEQUACY OF THE 2015 IRP AND ACTION PLAN

Based on the Division's review of the IRP and its participation throughout the 2015 IRP cycle, the Division finds that the Commission's 1990 Standards and Guidelines (contained below in Appendix A) have been reasonably met in the Company's 2015 IRP, given the uncertainty of the lowest cost resource that the Division discussed previously. The 2015 IRP has also adhered to the procedural requirements of an IRP, which are defined in the same IRP Order on Standards and Guidelines.[32] The Division points out that any issues that are not discussed herein are neither accepted nor rejected.

Next, the Division reviewed the adequacy[33] of the 2015 IRP Action Plan in terms of whether it complies with each of the Procedures, Standards and Guidelines (Guidelines) stemming from the Commission's 1992 Report and Order in Docket No. 90-2035-01.

The Company's Action Plan is based on the type and timing of resources in the 2015 preferred portfolio and identifies specific resource actions the Company will take over the next two to four years. The Company will issue unbundled Renewable Energy Credits (REC) requests for proposals at least annually to meet RPS compliance requirements in Washington and California, but will defer seeking unbundled RECs in Oregon since the Company's projected bank balance of RECs extends out through 2027. The Company will sell vintage RECs through 2016 that are no longer required to meet RPS compliance obligations.

The Company will continue evaluating its shortlist of bidders on its request for proposal (RFP) seeking up to seven megawatts of solar capacity to meet Oregon's 2020 solar capacity standard. In addition, the Company plans to acquire energy efficiency resources in 2015 through 2018 at annual incremental capacity additions starting at 133 megawatts and increasing to 146 megawatts per year.

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[32] Report and Order on Standards and Guidelines, Docket No. 90-2035-01, June 18, 1992, pp. 40-41.
[33] Id.

The Division notes that the 2015 Action Plan is more succinct than prior years. Again, this is due to the uncertainty in moving forward with action items in an environment where the only certainty is the fact that the 2017 IRP will be significantly different than this IRP. There are no new generating resources in the Action Plan. The Company intends to complete construction of the Wallula to McNary transmission project and continue Energy Gateway permitting. There are no new emission control installations in the Action Plan. However, the Company plans a natural gas conversion to the Naughton 3 Unit in 2018.

Near-term resource needs continue to be met with DSM and FOTs. Energy efficiency is up 59 percent by 2024 relative to the 2013 IRP. Reliance on FOTs is reduced relative to the 2013 IRP Preferred Portfolio, with no east-side market purchases at Mona for the first ten years of the IRP planning cycle.

In the preferred portfolio the first thermal resource, a 423 megawatt combined cycle gas plant, is added to the portfolio in 2028. 2,800 megawatts of existing coal capacity is assumed to retire or be converted to burn natural gas by the end of the 20-year planning period. Cholla Unit 4 permitting will be pursued to cease coal-fired operations by the end of April 2025. 816 MW of QF PPAs from wind and solar projects are expected to come online in 2015 and 2016. Carbon dioxide emission are projected to fall below 1990 levels by 2025 and fall below 1990 levels by 14 percent by 2034.

Although the Division is satisfied with the Company's IRP adherence, the Division has concerns or recommendations for the 2015 IRP Update and the 2017 IRP regarding distributed generation, energy storage, and qualified facilities that are discussed below.

<u>Distributed Generation</u>

The Company retained Navigant Consulting Inc. to perform the DG Technical Potential Study[34] for the 2015 IRP. Navigant not only studied technical potential but it also studied market

[34] Technical Potential is the maximum amount that is available without consideration of costs, or adoption rates. 2015 Integrated Resource Plan, Volume I, p. 72.

potential[35] and levelized cost of energy (LCOE)[36] for each DG resource in each of the six states served by the Company. Navigant did not study all types of DG technologies. Mainly due to the adoption of the various technologies, Navigant found it necessary to study only solar photovoltaic (PV), small-scale wind, small-scale hydro and Combined Heat and Power (CHP) for both reciprocating engines and micro-turbines to gain a perspective of technical potential. The Navigant study does not include the capacity additions from qualified facilities.[37]

Navigant reports the following findings:

> The major difference in the treatment of DG in the 2015 IRP is the application of DG as a reduction to load. The Navigant Study identifies expected levels of customer-sited DG. The DG is then netted against the IRP load forecast rather than being selected as a utility resource. This methodology more accurately reflects drivers behind DG penetration, which is customer economics, not utility economics.[38]

The Division finds that the Company appears to compare DG to DSM as one and the same for the 2015 IRP cycle. Although DG does reduce load, the utility sees DG differently than it sees DSM from an actual operating standpoint. Whereas DSM is generally a constant reduction to load throughout the day, DG is not. DG impacts the utility differently and at different times throughout the day, whether it be the variability nature of renewable resources, system constraints, safety concerns, system balancing, need for spinning reserves, changes to pollution controls or transmission and distribution.

Navigant's claim that its method more accurately reflects drivers behind DG penetration as more customer economics than utility economics is somewhat misleading. DG should be considered both as customer economics and utility economics because DG customers both consume power and supply power to the grid. This changes the costs and benefits that accrue to the Company. It is not clear how Navigant's modeling accomplishes these aspects of DG or what impacts it

[35] Market Potential is a refinement of Technical Potential where Fisher-Pry S-Curve modeling is based on length of time needed for payback. Id. at p. 73.
[36] Levelized Cost of Energy takes total installation costs, incentives, annual costs such as maintenance and financing costs, and system energy output, and calculates a net present value in $/kWh. See Volume II, Appendix O, pp. 1-3.
[37] PacifiCorp's 2015 Integrated Resource Plan, Volume II, Appendix O, p. 5-4.
[38]Id. at Volume I, p. 72.

would have on determining the preferred portfolio. However, as DG penetration continues to increase and at the rate forecasted by Navigant, it should not be treated as solely a reduction to load. The Company's decisions about how to maintain clean reliable power for its customers now, and at greater DG penetration levels in the future, will likely be different as DG and DSM penetration increase.

Residential and small commercial customer DG penetration does not currently impact the Company on a grand scale as noted in the 2015 IRP. However, as of year-end 2014, the Company had 8,266 net metering customers throughout its six-state territory, generating 70 megawatts using various DG technologies--a year-over-year increase of 48 percent.[39] Whereas, the Company has some control over DG resources at the utility-scale level through the power purchase agreement process, it has little control over residential and small commercial renewable resource uptake. The Division suggests renewable resources and DG be considered in greater detail in the Company's future IRPs as its own supply side resource. The Division also recommends that the Commission order the Company to conduct an updated DG potential study for the 2017 IRP and present the study findings at an IRP public stakeholder meeting. The Division requests that the authors of the study be available at that time to answer any specific questions related to the study itself, including the depth of the study, the methodologies used, the study findings, etc.

<u>Energy Storage</u>

Energy storage is modeled in the 2015 as a stand-alone supply side resource. However, it could also work in conjunction with DG. Storage is needed with some renewable resource technologies in an effort to make those renewable resources more dispatchable as supply side generation. Other storage technologies are used to enhance power reliability and utilize storage systems as spinning reserves for capacity/load requirements throughout the day. For example, pumped storage can be used to help mitigate peak load demand as water is pumped back to storage, thus reducing load requirements. Compressed air energy storage (CAES) and batteries are used for

[39]Id. at p.66.

longer duration storage as well. Flywheel technologies can be used for ancillary voltage control and intermittency problems associated with renewable resources.

The Company retained HDR Engineering (HDR) to conduct an energy storage screening study for the 2015 IRP.[40] HDR explores different utility-scale and distributed-scale energy storage technologies and defined their applications, performance characteristics, and estimated annual capital and operating costs. HDR presents its summary in Table 6.7 of the 2015 IRP, Volume I on page 116. Table 6.7 summarizes the different technologies studied in the HDR report, including Flywheel, Lithium-Ion batteries (Li-Ion), Sodium-Sulfur (NaS), Vanadium Redox (VRB), Pumped Storage, and Compressed Air Energy Storage (CAES). The table suggests pricing[41] ranging from $675 per kWh to $2,862 per kWh and capacities of 1 MW to 600 MW and durations from .25 hours to 10 hours. As modeled by HDR, storage has potential as a stand-alone supply side resource along with DG applications to make it more dispatchable. However, it is not selected as a least-cost/least-risk resource in the 2015 preferred portfolio.

The Company considers storage as a supply side resource instead of a reduction to load as it does with DG. Perhaps the Company had appropriate reasons in this IRP for modeling DG and storage the way they are, such as the variable nature of DG and storage in terms of uptake, available technologies, capital costs, and other aspects like system impacts. However, as the economics surrounding DG and storage continue to become more cost effective, they both need to be modeled in greater detail in future IRPs. The Division suggests that DG and storage be modeled together as a supply side resource, not separately, and in the case of DG, not simply a reduction to load as explained previously. The Division recommends the Company look into changing the way energy storage is modeled in its future IRPs. In addition, due to the rapidly emerging energy storage technologies, the Division recommends the Commission require the Company to file an updated energy storage screening study in its 2017 IRP and present the findings of the study to the public stakeholders in an IRP public meeting. As with the DG

[40]Id. at Volume II, Appendix Q, p. 497.
[41] In 2014 dollars.

potential study, the Division recommends that the authors of the studies be present at the stakeholders meeting to answer any questions the audience might have related to the details of the study and its findings.

Issues Regarding Qualifying Facilities

PacifiCorp's 2015 IRP includes in its Preferred Portfolio load and resource balance line items for qualifying facilities (QF) for the 2015-2024 period.[42] Table 8.8 shows the assumed East-side qualifying resources amount to about 330 megawatts and an average of about 123 megawatts on the West side. The Company's practice has been to include only those QFs that it has under contract and then remove the QF's capacity when its contract term expires. The Company's practice has been to include only those QFs that it has under contract. The Company does not assume that all QF contracts will necessarily renew at the end of the contract term. This results in some the decline of QF power over the study period.

However, the issue of the potential for substantial future, and perhaps unwanted, capacity being delivered to the Company via qualifying facilities has arisen in Utah in Docket No. 14-035-140, which in part dealt with modifying Schedule 38 in order to better manage the QF pricing queue to, among other things, discourage projects that were not ready to move forward from holding a queue position for lengthy periods of time. More recently the Company filed an application with the Commission in Docket No. 15-035-53 to reduce the maximum term for a QF contract to three years. The main thrust of that filing is that the Company is overwhelmed with QF applications that if all, or a significant portion, of these projects were built would result in a disruption of the Company's system operations, including the planning process, to the detriment of customers. The 3,692 megawatts of new QF contracts system-wide together with the existing QF contracts would provide 83 percent of the Company's average retail load and 114 percent of the Company's minimum retail load.[43]

[42] Docket No. 15-035-04, PacifiCorp's 2015 Integrated Resource Plan, Table 8.8, Vol. I, p. 197.
[43] PacifiCorp's Application in Docket No. 15-035-53, paragraph 15, pp. 6-7.

The surge in potential QF capacity is largely ignored in the current IRP. As indicated above, the Company assumes a relatively flat approximately 450 megawatts from QF contracts for the next ten years. However, in the 2015 IRP the Company did provide three sensitivity runs that may provide a flavor for how much more QF capacity might affect the system. These sensitivity runs were S-05 (High Distributed Generation Forecast),[44] S-09 (indefinite extension of the production tax credit),[45] and S-12 (Stakeholder Solar Cost Assumptions).[46] Each of these sensitivity runs were benchmarked against the core base case C05-1, and not the Preferred Portfolio.[47] C05-1 had a PVRR of $26,646 compared with $27,194 for S-05, $27,872 for S-09, and $27,209 for S-12 (values are millions of dollars).[48] These results suggest that a portfolio with high levels of QF projects may be more costly to ratepayers than without the QFs. However, these sensitivity runs are only very rough proxies for the costs or benefits to ratepayers for much higher levels of QF capacity than assumed in the 2015 IRP.

The Division recommends that the Commission order the Company to prepare IRP-type analyses in conjunction with its 2015 IRP Update showing the effects on resource acquisition and retail ratepayer cost impacts if, over the following three years, the Company acquires (1) 1,000 megawatts of additional solar PV capacity through new QF contracts, and (2) 3,000 megawatts of additional solar PV capacity through new QF contracts. Whether or not such analyses would be requested after the 2015 IRP Update will depend upon the situation a year from now.

SUMMARY OF RECOMMENDATIONS

As discussed above, the Division believes the 2015 IRP and Action Plan are adequate and should be acknowledged. However, the Division summarizes its findings and recommendations to the Company and the Commission that it believes will improve the IRP process for the 2015 IRP Update and the 2017 IRP below:

[44] Docket No. 15-035-04, PacifiCorp's 2015 Integrated Resource Plan, Vol. II, p. 197 and pp. 369-371.
[45] Id. at p. 201 and pp. 381-383.
[46] Id. at Volume I, Table 8.8, p. 197.
[47] Id.at pp. 197 ff.
[48] Id. at Vol. II, p. 157 and p. 217.

- The Division recommends the Commission acknowledge the Company's 2015 IRP and Action Plan and recognize the balanced process improvements and increased transparency the Company has made in the 2015 IRP.

- The Division recommends the Commission acknowledge Wallula to McNary transmission line with the caveat that acknowledgement will not guarantee favorable ratemaking treatment. Prudency and costs should be determined at the time of a general rate case proceeding.

- The Division recommends that the Company ensure that vendors or consultants are made available in person or on the telephone on the date that the respective supplemental study is being presented to IRP stakeholders.

- The Division recommends the Commission order the Company to continue to refine and vet the SBT before the larger stakeholder group before any project goes through the SBT in future IRPs. The Division requests that the Company hold a separate SBT meeting for all stakeholders. Any project that goes through the SBT in future IRPs needs to be subjected to stochastic risk analysis to determine risk and other performance metrics.

- The Company should explain in its 2015 IRP Update if and how requirements from FERC Order No. 1000 will affect the Energy Gateway plans and future IRPs, including inter-regional planning.

- The Division recommends that the Commission require future IRPs to present a contingency plan for the reliance on FOTS to be used in the event that market supplies tighten and prices increase significantly.

- The Division recommends the Commission require the Company to continue to analyze the planning reserve margin its 2017 IRP.

- The Division recommends the Commission encourage the Company to continue to develop its acquisition path analysis and possibly address other trigger events as the future unfolds.

- The Division recommends that renewable resources and DG and be modeled as separate supply side resource in the 2017 IRP rather than a reduction to load. The Division also recommends that the Commission order the Company to conduct an updated DG potential study for the 2017 IRP and present the study findings at an IRP public stakeholder meeting with the authors of the study present.

- The Division recommends the Commission require the Company to file an updated energy storage screening study in its 2017 IRP, update the cost assumptions, and consider modeling changes for energy storage. The Division requests that the Company present the findings of the study at a public stakeholder meeting, with the author present

- The Division recommends that the Commission order the Company to prepare IRP-type analyses in conjunction with its 2015 IRP Update showing the effects on resource acquisition and retail ratepayer cost impacts if, over the next three years, the Company acquires (a) 1,000 megawatts of additional solar PV capacity through new QF contracts and (b) 3,000 megawatts of additional solar PV capacity through new QF contracts.

- The Division requests that the Commission assign the 2017 IRP filing the Docket Number 17-2035-01 for filing purposes and continue with the docket naming convention so that parties know where to look for reference material from prior IRPs.

- The Division also recommends that the Company hold a separate technical conference in the 2017 that includes the IRP department and the DSM department, as was done this year.

- The Company should present to the larger stakeholder group all state-specific programs or reports that impact the IRP or that go into IRP assumptions, such as the Energy Trust of Oregon's work that determines DSM potential, or the Northwest Power Pool and Council's work that influences DSM, etc.

CONCLUSION

The Division appreciates the effort of PacifiCorp's IRP Team, the preparation for the meetings, the responsiveness to data requests and questions, and the professionalism of the IRP staff in addressing concerns and suggestions from outside stakeholders. The Division also acknowledges the hard work and contributions of the other stakeholders throughout the 2015 IRP process. The Division believes that the Company adequately complied with the Commission's Standards and Guidelines promulgated in its 1992 order in Docket No. 90-2035-01 and directions in more recent orders. The Division recommends that the Commission acknowledge PacifiCorp's 2015 IRP and take action on the Division's recommendations as summarized above.

cc:

Bob Lively, Rocky Mountain Power
Michele Beck, Office of Consumer Services
Service List

APPENDIX A: STANDARDS AND GUIDELINES[49]

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. 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.

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.

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

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.