ITEM NO. 1

PUBLIC UTILITY COMMISSION OF OREGON
STAFF REPORT
PUBLIC MEETING DATE: December 17, 2015

REGULAR X **CONSENT** ____ **EFFECTIVE DATE** **Upon Commission's Approval**

DATE: November 23, 2015

TO: Public Utility Commission

FROM: John Crider JC

THROUGH: Jason Eisdorfer and Aster Adams

SUBJECT: PACIFICORP d/b/a/ PACIFIC POWER: (Docket No. LC 62) Acknowledgement of 2015 Integrated Resource Plan.

STAFF RECOMMENDATION:

Staff recommends the Commission acknowledge PacifiCorp's (PAC or Company) 2015 Integrated Resource Plan (IRP) with certain considerations.

DISCUSSION:

Procedural History

PAC filed its 2015 IRP on March 31, 2015. On August 27, 2015, Commission Staff (Staff), Oregon Department of Energy (ODOE), Renewable Northwest (RNW), Industrial Customers of Northwest Utilities (ICNU), Sierra Club (SC), Citizen's Utility Board (CUB), Renewable Energy Coalition (RC), and Northwest Energy Coalition (NWEC) filed initial comments regarding PAC's IRP. The Company filed reply comments on September 24, 2015. Final comments by Staff, ICNU, RC, SC, RNW, NWEC, CUB, and ODOE were filed on October 15, 2015, and the Company's final comments were filed November 5, 2015.

Prior to filing the IRP, PAC held seven public stakeholder meetings and two additional technical workshops. Stakeholders were allowed and encouraged to provide comments to the Company throughout the development process, including through a newly designed online form.

General Description of the IRP

The IRP details a balanced consideration of cost, risk and uncertainty in developing a number of potential future generation portfolios in order to meet system load reliably over the next twenty years.

At the end of the planning window, the Company's preferred portfolio reflects a reduction of nearly 2,800 MW of existing generation through coal plant retirements.

PacifiCorp plans for an increased demand side management (DSM) acquisition rate, meeting 86 percent of load growth in the first ten years of the planning cycle with energy efficiency. All other load growth is met through front office transactions (FOTs) (i.e., the bilateral power market) until 2028 when the first thermal resource is added (a natural-gas fired turbine).

This IRP reflects a near-term expectation of low gas fuel prices and resultant low market power prices. The combination of these two commodity forecasts calls for unusually low power cost in the early years of the planning horizon, increasing gradually over the latter years of the study.

With the Company's reliance on DSM and front office transactions to meet near term load growth, the 2015 Action Plan calls for no new generation plants and no near term expenses for emissions control and environmental compliance, reflecting very little additional rate impact over the near-term planning horizon.

Compliance with Commission IRP Guidelines

Staff is satisfied that the Company has reasonably complied with the Commission IRP guidelines. However, Staff does have a few reminders for the Company.

Guideline 1 requires that the plan be consistent with Oregon and federal energy policies. PacifiCorp must remain diligent in ensuring that future assumptions and analysis related to regional haze, the Clean Power Plan (CPP), and all other environmental constraints be properly modeled to reflect adopted policies. As an example, if the State of Oregon adopts a mass-based approach to CPP compliance, the Company's modeling must reflect this (the current IRP assumed a rate-based approach).

Guideline 7 calls for evaluating demand response, "including voluntary rate programs" (Order 07-002 at 16) on par with other options for meeting load. In Order 07-002, the Commission reiterated that the Company should include Demand Response (DR) in portfolio modeling. Staff reminds the Company of the importance of considering all potential DR programs in its IRP, and to include the most cost effective DR in the portfolios which are included in risk modeling.

Finally, Guideline 12 calls for the Company to *"... evaluate distributed generation technologies on par with other supply-side resources"* and to *"consider, and quantify where possible, the additional benefits of distributed generation."* Historically, the Commission has been satisfied with planning that uses "one hour" granularity and that generally views planning from a transmission-side perspective.

At present, and increasingly into the future, the importance of distributed generation and its effects (positive and negative) on the grid will have an increasing influence on the overall system health and efficiency. Many of the effects of distributed generation, and renewables in general, take place in the subhourly time intervals. Many benefits and costs of distributed solar (as well as those related to distributed storage) need to be tallied on a timeframe of minutes, not hours. For these reasons, Staff believes the Company must progress towards an IRP model that is capable of determining these subhourly costs and benefits.

Staff believes that ongoing compliance with Guideline 12 into the future will necessitate some means of deriving costs and benefits that accrue at a more granular level than "hourly". These subhourly benefits are typically associated with distributed renewable generation, but similar benefits are also provided by company participation in subhourly markets such as the energy imbalance market (EIM). Staff encourages the Company to continue developing the models so that they can accurately estimate subhourly benefits and costs.

Staff is satisfied that the Company has adequately met the IRP Guidelines.

Compliance with Previous IRP (LC 57) Order 14-252
At the conclusion of PacifiCorp's previous IRP docket, LC 57, the Commission issued Order 14-252, acknowledging the Company's 2013 IRP and adding several directives and Commission recommendations.

<u>Coal Plant Compliance and Pollution Control</u>
PacifiCorp was directed to provide quarterly updates to the Commission and guidance for data to include in future IRPs. The Commission also directed the Company to offer a series of workshops to discuss compliance strategies at specific plants. The Company provided the required quarterly updates on March 6, 2015, June 16, 2015, and a written

update on October 2, 2015. Staff believes the Company has satisfactorily complied with the Commission's directives.

<u>111(d) assessment</u>
The Commission directed the Company to work with stakeholders to develop the analysis regarding 111(d) compliance. Staff believes that PacifiCorp has adequately included stakeholders in the process. Staff expects a revision of the Company's 111(d) modeling in its 2015 IRP Update or its next IRP(depending on when Oregon's compliance plan is known) that correctly reflects both the U.S. Environmental Protection Agency (EPA) final rule and Oregon's implementation plan.

<u>Coal Plant Screening Tool</u>
The Commission directed the Company to include an updated version of the screening tool in the filing. The Company did so.

<u>DSM Related Recommendations</u>
In Order 14-252 the Commission recommended that PacifiCorp:

- Provide twice yearly updates on the status of DSM IRP acquisition goals to the Commission in 2014 and 2015, including a summary of DSM acquisitions from large special contract customers. Summarize where efforts have deviated from previously agreed upon action items and report on progress toward specific DSM targets for all states other than Oregon.

- Include in the 2014 conservation potential study information specific to PacifiCorp's service territory for all states other than Oregon that quantifies how much Class 2 DSM programs can be accelerated and how much it will cost to accelerate acquisition.

- Include a PacifiCorp service area specific implementation plan as part of the 2015 IRP filing. At twice yearly updates to the Commission, provide a summary of savings potential, gaps and how PacifiCorp's specific implementation plan and programs are achieving the identified potential.

- In future IRPs, PacifiCorp will provide yearly Class 1 and Class 2 DSM acquisition targets in both GWh and MW for each year in the planning period, by state.

Staff is satisfied that the Commission comments related to Class 2 DSM in the 2013 IRP have been addressed; specifically:

- PacifiCorp provided updates on the status of the DSM IRP acquisition goals to the Commission in 2014 and 2015 at public meetings held on August 6, 2014, December 3, 2014, and March 10, 2015;
- The conservation potential study included analysis of how much DSM resource could be accelerated and how much it would cost to do so for all states;
- Service area specific implementation plans were provided within the Plan; and
- Yearly energy and capacity from Class 1 and Class 2 DSM acquisition targets were provided by state.

In summary, Staff is satisfied that the Company has adequately addressed all of the Commission's directives resulting from Order 14-252.

Action Item Discussion

The Company offers the following Action Items (1 – 5) for the time period 2015-2019. Parties' responses to the Action Items are discussed under each particular item. If a party is not listed, it did not address the issue in comments.

Action Item 1 –Actions related to the Renewable Portfolio Standards (RPS)

a) *RPS Compliance – the Company will continue to pursue unbundled RECs*[1] *to meet RPS requirements*
b) *REC Optimization – the Company will sell older RECs not required for compliance*

Parties Positions

NWEC – NWEC questions whether enough physical renewable resources are being built when the company relies on banked unbundled RECs for compliance[2] as it has chosen to do in this IRP. NWEC notes that physical renewables offer system advantages in areas of flexibility and reliability than may not be realized by using banked RECs.

Staff supports a least-cost approach to managing the Company's REC bank and supports the Company's proposed Action. Staff also notes that the Company's pursuit of banked unbundled RECs is consistent with the Oregon RPS rules. However, Staff is

[1] REC – Renewable Energy Credit. One credit is issued per each megawatt-hour produced.
[2] NWEC Opening Comments p.1.

of the opinion that these actions - 1(a) and 1(b) - should be considered normal business practice and do not require acknowledgement.

Staff supports Action Items 1(a) and 1(b) but does not believe it requires Commission acknowledgement as it reflects normal good business practice and is not a major resource acquisition.

Staff notes that the modeling results demonstrate that, based on the cost input assumptions, new renewables do not represent the least-cost solution to meeting the Company's load-resource balance in this IRP. Unless the cost inputs change dramatically, it appears that near-term new renewable construction may need to be policy-driven since it is not cost-driven.

c) *Fulfillment of Solar Capacity Standard through an Request for Proposals*

No parties commented on this Action Item.

The Company's action item to fulfill its solar compliance obligation through the "request for proposal" (RFP) process is reasonable and it helps assure that the compliance will be achieved at least cost and risk.

Staff recommends acknowledgment of Action Item 1(c).

<u>Action Item 2 – Front Office Transactions</u>
The Company plans to meet summer peaks in the near term with short-term firm purchases.

Parties Positions

RC notes that the Company is heavily dependent on front office transactions to maintain load-resource balance in the front years of the analysis. RC questions whether the wholesale market has sufficient depth to meet the PAC summer peak for the next 12 years.

Staff supports this Action Item but does not believe it requires Commission acknowledgement as it reflects normal good business practice and is not a major resource acquisition.

Although Staff supports the Company's pursuit of front office transactions, it also shares the concerns regarding the depth of the market raised by RC. Staff attempted to discover quantitative support for the Company's assertions of market depth but PacifiCorp was unable to provide such quantified justification. Nevertheless, the Company did provide enough qualitative support, coupled with Staff's knowledge of past levels of front office transactions, to provide a reasonable basis for market depth assumptions for this IRP. In future IRPs, especially if substantial resource acquisition costs are at risk, Staff expects the Company to provide satisfactory quantitative support for assumptions regarding the depth of the power market.

> Staff recommends the Commission direct the Company to provide quantitative analysis supporting its assumption of market depth during the stakeholder process and in the body of future IRPs.

<u>Action Item 3 – DSM Actions</u>

a) *Pursue a west-side irrigation load control pilot*

Parties Positions

No parties commented specifically on this Action Item, although NWEC and CUB both provide general support for PAC's increase in DSM acquisition targets.

Staff supports an irrigation load control program but is not convinced a pilot is necessary. Irrigation load control programs are well-established elsewhere and Staff believes the Company could adopt such a program without the need for a pilot. Nevertheless, Staff agrees a pilot program would be a positive addition to the Company's current offerings.

> Staff recommends acknowledgement of Action Item 3(a).

b) *Acquire cost effective Class 2 DSM*

The Company proposes to acquire 2,385 GWh of Class 2 DSM between 2015 and 2018, a substantial portfolio-wide increase (37 percent) compared to the 2013 IRP Action Plan. The Company credits this identification of additional cost-effective energy efficiency (EE) largely to increased lighting potential, specifically growth in LED opportunities. Concerns from Staff and other stakeholders from the last IRP regarding

Oregon ratepayers being burdened by a lack of sufficient DSM in other states will begin to be addressed if these portfolio wide targets are met. Staff is supportive of these short term action plan targets as being well informed by thorough analysis for current commercially-available resources.

Parties Positions
SC states that the projection of annual savings is "overly conservative"[3] and lower than what has been achieved in the past. SC notes that this outcome is largely influenced by the process which screens out measures which have not yet reached commercial availability. SC goes on further to note that the individual state ramp rates for EE are lower than the savings targeted by leading utilities.[4]

CUB and NWEC offer generally supportive statements regarding PAC's approach to DSM and energy efficiency in this IRP although neither speaks specifically to this Action Item.

Since Staff and Oregon stakeholders continue to be interested in tracking the Company's progress in growing efficiency programs in other states, Staff recommends continuing to have the Company report to the Commission two times per year on progress in other states towards these new, higher goals.

Staff recommends acknowledgement of Action Item 3(b), and proposes the following additional recommendations:

- *Continue to provide twice yearly updates on the status of DSM IRP acquisition goals to the Oregon Commission in 2016 and 2017 at regular public meetings.*
- *Include annual incremental summer and winter peak demand capacity (MW) corresponding to 2015 through 2018 Class 2 DSM annual energy savings targets.*
- *For the 2015 IRP Update, provide model run results of the preferred portfolio with base case DSM and with accelerated DSM for comparison purposes.*

[3] Sierra Club Opening Comments, p.1.
[4] Id., p.3.

<u>Action Item 4 – Coal Resource Actions</u>

a) *Naughton Unit 3 – Issue an RFP to procure gas transportation and continue plans for gas conversion.*
b) *Dave Johnston Unit 3 – continue on path to avoid SCR*[5] *and shutdown in 2027*
c) *Wyodak – Continue legal actions to avoid SCR*
d) *Cholla Unit 4 – Continue efforts to avoid SCR and cease coal operation in 2025*

Parties Positions

NWEC commented generally about this Action Item and offered support for PAC's approach to its coal resources in this IRP. CUB also is "largely satisfied" with the Company's approach to coal resources in this IRP.[6]

SC ran an independent System Optimizer analysis and took issue with some of the scenario assumptions adopted by PAC. SC questioned whether PAC had improperly performed the analysis, primarily by not allowing the model to retire coal plants within the program.

Although these concerns seem valid, in the end the revenue requirement calculated by SC through its use of the model was significantly higher than the PVRR established by the Company through its own analysis. Staff finds nothing in SC's results that contradict or call into question PAC's analysis – the Company's approach was proven to be least-cost when compared to SC's analysis.

Although these four action items do not represent resource acquisition *per se*, Staff believes that the Company's actions represent an active involvement in the deferment or avoidance of a large enough cost to be considered an "avoided major resource acquisition" or certainly an avoided significant capital expense. In this light, Staff recommends acknowledgement of Action Items 4(a-d). However, as noted in its Opening Comments, Staff believes the economic case for Naughton's conversion versus shutdown is close enough to demand ongoing analysis. A large enough change in assumed natural gas prices and/or new plant capital expenses could reverse the analysis results, indicating that a periodic review of the analysis is appropriate and may result in a re-evaluation of options for Naughton. At this point in time, though, the gas conversion is justified.

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[5] "Selective Catalytic Reduction" (SCR).
[6] CUB's Opening Comments, pp 3-4.

Staff recommends acknowledgement of Action Items 4(a-d)

Action Item 5 – Transmission Actions

The Company proposed the following transmission action items:

Table 1: Action Items Discussed by Staff

Action Item #	Action Item Category	Action Item
5(a)	Energy Gateway Permitting	Continue permitting for the Energy Gateway transmission plan, with near term targets as follows: - For Segments D, E, and F, continue funding of the required federal agency permitting environment consultant actions to achieve final federal permits. - For Segments D, E, and F, continue to support the federal permitting process by providing information and participating in public outreach. - For Segment H (Boardman to Hemingway), continue to support the project under the conditions of the Boardman to Hemingway Transmission Project Joint Permit Funding Agreement.
5(b)	Wallula to McNary 230 kilovolt Transmission Line	Complete Wallula to McNary project construction per plan with 2017 expected in-service date. Continue support the permitting process for Walla Walla to McNary.

Action Item 5(a): Energy Gateway Permitting

PacifiCorp requests acknowledgment of this action item, which generally covers continued permitting and support of the pre-construction phases. The Company is requesting acknowledgement of permitting actions for the following segments: Windstar to Populus (W2P or Segment D),[7] Populus to Hemingway (P2H or Segment E),[8] Aeolus to Mona (A2M or Segment F),[9] and Boardman to Hemingway (Segment H).[10]

[7] Segment D is part of the Gateway West project. This segment "will stretch approximately 488 miles starting at the Windstar substation near Glenrock, Wyoming, proceeding south to Medicine Bow and then spanning across southern Wyoming to the Populus substation near Downey, Idaho. This segment will include seven expanded or new substations and will enable access to existing and new generating resources, including wind, and will deliver electricity from these sources to customers throughout both

Parties Positions

NWEC believes that the regional flattening of load forecasts coupled with anticipated coal plant retirements creates a window of opportunity to reassess how transmission is considered in the IRP process.[11] NWEC states that coordination is a key aspect, so that existing and new transmission can be utilized for new renewable projects. NWEC recommends that the next IRP contain a reassessment of the Gateway strategy.

Staff recognizes the uncertainty in developing these segments, given that their anticipated in-service dates are in 2019 and beyond. However, such uncertainty should not hinder the Company's efforts to continue exploring the projects in light of the significant preliminary benefits of these segments as shown by the Company through discovery.[12] Therefore, Staff recommends that the Commission acknowledge Action Item 5(a).

Staff recommends acknowledging the Company's Action Item 5(a)

<u>Action Item 5(b): Wallula to McNary 230-Kilovolt Transmission Line</u>

Staff thoroughly analyzed this project in its Opening Comments from an economic point

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companies' service territories." (See http://www.pacificorp.com/tran/tp/eg/gw.html.) The anticipated in-service date for this project is between 2019 and 2024 (see PacifiCorp's 2015 IRP, Volume I, page 57).

[8] Segment E is part of the Gateway West project. This segment "originates at the Populus substation near Downey, Idaho, and includes two transmission lines that run approximately 502 miles across Idaho to the Hemingway substation near Melba, Idaho. The Populus to Hemingway segment will include five expanded or new substations, and will enable access to existing and new generating resources, including wind, and will deliver electricity from these sources to our customers."(See http://www.pacificorp.com/tran/tp/eg/gw.html.) The anticipated in-service date for this segment is between 2019 and 2024. (See PacifiCorp's 2015 IRP, Volume I, page 57.)

[9] Segment F is part of the Gateway South project. This segment extends "approximately 400 miles from the planned Aeolus substation in southeastern Wyoming into the new Clover substation near Mona, Utah." (See PacifiCorp 2015 IRP, Volume I, page 51 and http://www.pacificorp.com/tran/tp/eg/gs.html.) The anticipated in-service date of this segment is between 2020 and 2024. (See PacifiCorp's 2015 IRP, Volume I, page 57.)

[10] Segment H is part of the Gateway West project. This segment is a 500-kilovolt line that would run approximately 300 miles from a new substation proposed near Boardman, Oregon, to the Hemingway substation near Melba, Idaho, southwest of Boise, Idaho." The anticipated in-service date is sponsor-driven. (See PacifiCorp's 2015 IRP, Volume I, page 57.) Per Idaho Power Company's (Idaho Power) 2015 IRP, the in-service date is expected to be in 2021 or beyond. (See Idaho Power 2015 IRP, Volume I, page 68 at https://www.idahopower.com/pdfs/AboutUs/PlanningForFuture/irp/2015/2015IRP.pdf.)

[11] NWEC opening comments, p7.

[12] See PacifiCorp response to Staff DR 67.

of view and stated that it cannot support an acknowledgment this project because of its poor economic justification.[13]

In its Reply Comments,[14] the Company emphasized that this project is driven by its Open Access Transmission Tariff (OATT) federal obligation. The Company also commented that it has a point-to-point transmission service agreement to provide 25 MW of transmission service by December 31, 2015, over the new transmission line pursuant to requirements of its OATT.

During subsequent discovery, the Company disclosed that it has investigated several alternatives to comply with the FERC transmission requirements represented in its OATT. The Company has received requests for transmission of wholesale power that, according to its OATT, it is obliged to supply. The Company explored providing this service by re-conductoring and otherwise enhancing the existing transmission line. However, any upgrades to the existing line would entail a transmission outage of the line and a need to purchase replacement capacity. The Company's analysis shows that any of the solutions involving upgrades of the existing line are at least 30 percent more expensive than building a new line due to the additional costs incurred to mitigate the line outage.

After evaluating all of the potential compliance paths, the Company concluded that constructing the new Wallula to McNary Transmission Line was the least-cost option for meeting its obligation per its OATT.

The Company further stated that it would not object to the Commission acknowledging Action Item 5(b) with clarifying language to reflect that the action item is concerned with regulatory compliance, not economics.

Staff recommends acknowledgement of Action Item 5(b), with modified wording:

"Complete Wallula to McNary project construction per plan, with 2017 expected in-service date, as required for regulatory compliance with PacifiCorp's FERC-approved OATT. Continue to support the permitting process for Walla Walla to McNary."

[13] See page pages 25 through 31 of Staff Opening Comments.
[14] Generally, see pages 19 through 22 of PacifiCorp Reply Comments.

Other Issues

SC – Battery Storage
SC spends several pages of its comments describing illustrative examples of how battery storage is used at other utilities.[15] SC states that the Company has overstated the costs of future energy storage. PacifiCorp has estimated the costs based on historical costs which are two to three times more than costs anticipated in the near future. Further, the IRP estimates future replacement costs of energy storage at the same price as current costs, despite evidence that future costs will drop significantly. Finally, SC claims that the Company failed to take into account the numerous key benefits that storage offers.[16]

Staff also considers storage one of the key elements for analysis in upcoming IRPs and will closely scrutinize cost and usage assumptions in the next IRP.

RNW, ODOE, NWEC, and Staff – CPP Modeling
RNW is concerned that the Company's choice to analyze CPP compliance through a rate-based approach is not in alignment with either the final EPA rule or Oregon's probable implementation plan. RNW urges the Company to consider a mass-based model for CPP compliance.[17]

RNW also questions the Company's interpretation of statute and rules regarding the interaction between renewable energy credits, the Oregon RPS, and CPP compliance. RNW is concerned that the Company may be using the same MWh of energy for both RPS and CPP compliance, a situation that may represent double-counting and may not be acceptable for compliance.[18]

ODOE also notes that carbon attributes may not be able to be separated from other environmental benefits of the REC, as the Company presumed. ODOE asks the Commission to instruct the Company that its base model must be compliant with existing state policy regarding RECs, and to include mass-based CPP compliance in its modeling.[19]

NWEC also has issues with potential double-counting of RECs for both RPS and CPP, and questions whether the rate-base modeling is accurate in face of the final rules.[20]

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[15] Sierra Club Opening Comments, p 10-17.
[16] Id. p 18.
[17] Renewable Northwest Opening Comments, p 3-6.
[18] RNW Opening Comments, p 5.
[19] ODOE Opening Comments, p 2.
[20] NWEC Opening Comments, p 3.

Staff shares these concerns regarding CPP compliance modeling. Staff notes that the Company's 2015 IRP was developed and filed before the EPA made its final 111(d) ruling. Some leeway must be given to the Company as to its modeling approach given that the final rule was unknown at the time the modeling was developed. Staff expects that CPP modeling in the next IRP will be informed by state policy and the EPA final rule.

RC – Avoided Cost Rates

RC notes that the Commission relies upon inputs from an acknowledged IRP to inform the calculation of avoided cost rates. For this reason, RC petitions that the Commission instruct the utilities to perform avoided cost filings concurrently with the IRP filing.

RC – Deficiency Demarcation

RC notes that during the ten-year period 2015-2024 PAC's IRP plan calls for annual capacity purchases that average over 840 MW per year. RC asserts that this fact represents a de facto resource deficiency, and should inform the avoided cost rates. RC believes this should lead to change in the resource deficiency demarcation.

Because of this, RC recommends the Commission not acknowledge the IRP since the 2028 year of deficiency is questionable, especially in light of the uncertainties surrounding EPA rules, wholesale power prices and availability, and transmission availability.[21]

Staff does not believe consideration of this issue warrants non-acknowledgement of the IRP. However, Staff believes that RC raises a valid point of policy – what is the threshold of capacity shortage that represents a demarcation between sufficiency and deficiency, below which the Company fills its needs with short term capacity contracts and above which a new physical resource must be acquired?

Staff notes that this issue is currently being investigated in Docket UM 1610.

ICNU, Staff- Winter Peak Capacity

ICNU notes that the Company's focus on meeting summer peak may not provide the resources necessary to meet the Western Control Area winter peak, which may also result in an excessive planning reserve margin.

Staff also raised this issue in opening comments.[22] Through discovery, the Company indicated that under some conditions it would have to increase FOTs or acquire new resources earlier than planned in the IRP in order to meet a west side winter peak. Staff

[21] RC Final Comments, p 1.
[22] Staff Opening Comments, p 31.

recommends that the Commission require the Company to analyze this specific scenario in the next IRP.

ICNU-Reserves Overstated
ICNU points out that the Company's modeling has not incorporated the recent change in North American Electric Reliability Corporation (NERC) standards (BAL-001-2) that portend to reduce reserve burdens.[23] ICNU states that Oregon customers should expect significant benefits once these new standards are accounted for.[24]

Staff agrees and recommends the new NERC standard BAL-001-2 be incorporated into future modeling.

ODOE Recommendations[25]

ODOE asks that the Commission make the following directives to the Company:

1. Direct the Company to use a method to constrain each stochastic modeling run to roughly comply with the 111d final rule;
2. Direct the Company to run the System Optimizer with a reasonable approximation for the effects of the final 111(d) rule on western wholesale power prices;
3. Instruct the Company that comparisons of various portfolios should use comparable assumptions on implementation of regional haze rules and other basic assumptions;
4. Instruct the Company to perform a full risk analysis on a more aggressive energy efficiency portfolio; and
5. Require comprehensive analysis of the system benefits of storage.

Staff supports the first three of ODOE's recommendations since they are both reasonable and should produce results that are more easily analyzed as "apples to apples." Staff also supports recommendations (4) and (5) because the tasks are well aligned with Oregon energy policy and will inform the Commission regarding critical strategic policy decisions on energy efficiency and storage.

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[23] Reliability Standard BAL-001-2 is designed to ensure that applicable entities maintain system frequency within narrow bounds around a scheduled value, and improves reliability by adding a frequency component to the measurement of a Balancing Authority's Area Control Error. See 151 FERC ¶ 61,048; 18 CFR Part 40 [Docket No. RM14-10-000; Order No. 810].
[24] ICNU Opening Comments, p 6.
[25] ODOE Opening Comments, p 4.

NWEC – Renewable Plants
NWEC points out that the preferred portfolio choice is highly driven by the natural gas forecast. It criticizes the high gas case gas costs as being too low and would like to see more renewables included in the results, rather than only gas expansion.[26]

Staff concurs that a higher gas cost would most likely lead to the model opting for increased renewable deployment. However, Staff has reviewed the gas forecast and finds it reasonable based on the recent historical downward trend of actual costs for natural gas in the Northwest.

Staff – Screening Metrics
PacifiCorp bases its screening of portfolios on two derivative metrics – the Upper Mean Tail Mean PVRR minus Fixed Costs, and the Risk Adjusted PVRR – both of which potentially obscure the importance of the underlying base metrics, and may lead to portfolio choices which are not actually least-cost or least-risk. These derivative metrics offer no added value from the base metrics and should no longer be relied upon for portfolio screening. Staff will continue its practice of applying additional metrics in its analysis of the Company's portfolio choices.

Staff – Full Participation in the California Independent System Operator (CAISO) Market
PacifiCorp recently announced its intention of investigating partnering with the CAISO in forming a regional Independent System Operator (ISO). Staff recognizes the customer benefits already realized by joining the EIM and would appreciate a better understanding of the costs and benefits of this collaboration with CAISO. Staff recommends that the Commission direct the Company to perform a cost and benefits study of partnering with the ISO and to file a report with the findings.

PROPOSED COMMISSION MOTION:

PacifiCorp's 2015 IRP be acknowledged with modifications as recommended by Staff as contained in this report and summarized in Attachment A to this report.

[26] NWEC Opening Comments, p 4.

ATTACHMENT A

Staff recommends acknowledgement of PacifiCorp's 2015 Action Plan with the recommendations contained herein, and summarized below:

Action Item	Description	Staff Recommendation
1(a)	RPS – pursue unbundled RECs	No acknowledgement required
1(b)	REC Optimization – sell older unneeded RECs	No acknowledgement required
1(c)	Fulfillment of solar capacity standard via RFP	Acknowledge
2	Front Office Transactions	No acknowledgement required
3(a)	Pursue a west-side irrigation load control pilot	Acknowledge
3(b)	Acquire cost effective Class 2 DSM	Acknowledge with Recommendations
4(a-d)	Coal related actions	Acknowledge
5(a)	Energy Gateway permitting	Acknowledge
5(b)	Compliance with FERC – Wallula to McNary	Acknowledge with amendment

Recommendations:

In addition to acknowledgement of the Action Plan items, Staff recommends that the Commission direct the Company to:

- Include sensitivity studies around solar costs (high, base, and low cost cases);
- Evaluate and consider the benefits of freed-up transmission due to plant closures;
- Implement ODOE recommendations:
    - Include the constraints needed for 111(d) compliance in all cost risk analysis ("PaR" analyses);
    - Estimate the effects of 111(d) compliance on western wholesale power prices;
    - Use the same Regional Haze assumptions when directly comparing portfolios;
    - Perform more risk analysis on portfolios that include accelerated EE as a resource; and
    - Require comprehensive analysis of the system benefits of storage.
- Include more robust analysis regarding the west Balancing Authority winter peak load/resource balance and portfolios to meet this peak load;
- Provide quantitative justification planning for the planning reserve margin of 13 percent;
- Encourage the Company to design several new Demand Response programs, including:
    - An irrigation load control program;
    - A residential direct load control pilot (water heaters, AC, thermostats, etc.);
    - An aggregator-led commercial Demand Response pilot;
    - An industrial load control pilot that operates to address peak load reduction and not restricted in use to emergencies and enhanced reliability; and
    - An innovative time-of-use rate pilot proposal that does not need to leverage AMI infrastructure in order to realize benefits to the customer and the utility.

- Provide quantitative justification for assumed levels of trading hub liquidity and depth;
- Utilize the Balancing Authority's Area Control Error (ACE) Limit (BAAL) NERC standard in forthcoming wind integration studies;
- Provide alternate 111(d) compliance paths, including mass-based solutions, with stochastic analysis for each;
- Update the available dynamic transfer capability between PacifiCorp's east and west balancing authorities in the modeling;
- Include an analysis of the benefits and costs of forming a Regional Transmission Operator (RTO) by partnering with the CAISO;
- Perform stochastic modeling on all portfolios with accelerated DSM;
- Continue to provide twice yearly updates on the status of DSM IRP acquisition goals to the Oregon Commission in 2016 and 2017 at regular public meetings;
- Include annual incremental summer and winter peak demand capacity (in MW) which corresponds to 2015 through 2018 Class 2 DSM annual energy savings targets; and
- For the 2015 IRP Update, provide model run results of the preferred portfolio with base case DSM and with accelerated DSM for comparison purposes.