BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

LC 62

In the Matter of PACIFICORP, dba PACIFIC POWER's 2015 Integrated Resource Plan.	Opening Comments

General Comments

In these Opening Comments, Staff provides input on the general Integrated Resource Plan (IRP) process and an evaluation of the supporting studies and screening tools that the Company used to select the final portfolios in the IRP analysis. Staff also provides an overall assessment of the IRP analysis and the formation of the Action Plan, and a discussion of specific areas of concern.

Staff recognizes the value the Company offers in providing a broad range of important supporting studies prior to undertaking the IRP. Staff also appreciates the willingness of the Company to address numerous stakeholder requests and concerns in preparation of the IRP, including running specific modeling scenarios and performing requested calculations.

However, it is not always clear to Staff exactly how the results of the many studies and analyses are incorporated into the final selection of portfolios to test. Staff would appreciate more detailed rationale whenever the Company considers, but dismisses, individual resource types or particular portfolios of resources. Related to this, Staff continues to have a concern about the use of certain metrics in screening out potential portfolios.

Clarity could be gained if the Company would include a narrative evaluation of each study, including an explanation of how the results of the study have informed the IRP. Staff is interested in knowing what the Company learned from each study and how the findings are being incorporated into the analysis. The Company would also have the opportunity to explain in detail how the conclusion to exclude certain technologies or resources from further analysis was reached.

Overall, the Company provides a thorough and robust process for developing the IRP. The Company has provided ample opportunity for stakeholders to provide input and involvement in the development of portfolios. The modeling of a range of futures is a reasonable approach to evaluating the portfolios, and the resultant Action Plan represents a reasonable combination of least-cost and least-risk solutions to meeting the Company's future load/resource balance.

Still, Staff does have several areas of concern with PacifiCorp's (PAC) analysis and methods. Of primary concern to Staff in this IRP are the assumptions the Company has made around compliance with the federal Environmental Protection Agency's (EPA) Clean Power Plan (i.e., "111(d)" rules), the continued use of derivative screening metrics, justification for the Wallula-to-McNary transmission project, and what appears to be weak support of demand response initiatives. These issues are discussed in detail below.

Review of Supporting Studies and Forecasts

Power Market Forecast

The Company used three wholesale electricity price curve assumptions in core case definitions: a base case (September 2014 official forward price curve or "Sep 2014 OFPC") and two scenarios ("111(d) + CO2" and "High CO2").

Staff contrasted the confidential electricity price forecast provided by the Company with the electricity price forecast provided by Bloomberg Professional Service for the period through 2020 for the following electricity hubs: Palo Verde (PV), Mid-Columbia (MidC), South of Path 15 (SP15), and North of Path 15 (NP15). The forward curves of Bloomberg Professional Service are as of September 2014, so they are contemporaneous to the Company's forecasts.

The graphs (see Confidential Figures 1-2 in Attachment A) illustrate that the Company's electricity price forecast for the first five years is consistent with that of Bloomberg Professional Service. Additionally, the prices provided by the Company for the subsequent period (i.e., 2021 to 2035) incorporate reasonable levels of prices (i.e., low, medium, and high).

Staff concludes that the Company's electricity price forecast is not unreasonable.

Natural Gas Forecast

PacifiCorp's gas price forecast as depicted on Volume I pages 149 and 168 compares favorably with gas price forecasts from the federal Energy Information Agency (EIA) and SNL, as shown in Figures 3-5 in Attachment A. PacifiCorp's gas price forecast also compares favorably with the forecasts used by Avista (Fig. 6) and Northwest Natural (Fig. 7) in their 2014 IRPs, also as shown in Attachment A.

As a result, Staff concludes that PacifiCorp's 2015 IRP gas price forecast is reasonable for planning purposes.

Transmission Assumptions

Staff reviewed how the transmission system topology used in the Company's modeling reflects the Company's transmission paths. In the Company's response to Staff DR 7, included as pages 1 and 2 of Attachment B, the Company provided sufficient information for Staff's analysis. Staff found that the Company's representation of its transmission system is not unreasonable.

Staff also considered whether the Company incorporated the transmission costs of generation resources in its analysis. In the Company's response to Staff DR 8, included as pages 3 and 4 of Attachment B, the Company explained how the costs of transmission integration and reinforcements are included in the resource portfolios. Staff found that the Company's assumptions are not unreasonable.

Finally, Staff reviewed whether the Company has incorporated in its modeling the additional 200 MW of "dynamic transfer capability" (DTC) that the Company is expected to rely on due to the Public Utility Commission of Oregon (OPUC) approval of the Company's request in Docket No. UP 315 (*PacifiCorp and Idaho Power's Joint Application for an Order Authorizing the Exchange of Certain Transmission Assets*). In Docket No. UP 315, PacifiCorp requested the exchange of certain transmission assets with Idaho Power Company that, among other things, will result in PacifiCorp having ownership and wheeling rights of 1,600 MW, of which 400 MW could be dynamically scheduled across three transmission lines that are part of the nexus between PacifiCorp's balancing authority areas (BAAs).[1] The OPUC approved the Company's request in Order No. 15-184.[2] Per the Company's filing in Docket No. UP 315, the transaction is expected to close on December 31, 2015.[3]

In part "a" to the Company's response to Staff DR 75, included as page 5 of Attachment B, the Company represented that it has not included the additional DTC that results from Docket No. UP 315 because the related change in transmission rights was uncertain when the transmission topology inputs for the 2015 IRP were locked down. Staff believes that the Company's response is reasonable. Nevertheless, Staff recommends that, for the 2015 IRP Update, the Company be required to update the DTC between PacifiCorp's BAAs.

Staff would like the Company to reflect this benefit in its modeling because when PacifiCorp filed its request in Docket UP 315, the Company clearly identified the associated benefits (e.g., the increased dynamic transfer capability between its BAAs).[4] When Staff recommended that the Commission approve

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[1] See Docket No. UP 315's Exhibit PAC/300, Vail/8, lines 21-23 and Exhibit PAC/300, Vail/9, line 1 at http://edocs.puc.state.or.us/efdocs/HAA/up315haa141821.pdf.
[2] See http://apps.puc.state.or.us/orders/2015ords/15-184.pdf.
[3] See page 8 of the Joint Purchase and Sale Agreement filed with the OPUC at http://edocs.puc.state.or.us/efdocs/HAA/up315haa141821.pdf.
[4] The multiple benefits are represented by the Company in Exhibit PAC/400, Duvall/1-2 at http://edocs.puc.state.or.us/efdocs/HAA/up315haa141821.pdf.

the Company's request, Staff recognized these benefits and, therefore, such benefits should be reflected in future IRPs.[5]

Staff concludes that the Company's transmission assumptions are reasonable.

Front Office Transactions Assumptions

The Company assumed the following maximum levels of "front office transactions" (FOTs) by market hub in its 2015 IRP:[6]

Market Hub/Proxy FOT Product Type	Megawatt Limit and Availability
Mid-Columbia Flat Annual ("7x24") and 3rd Quarter Heavy Load Hour ("6x16")	400 MW + 375 MW with 10% price premium, 2015-2034
California Oregon Border (COB) Flat Annual ("7x24") and 3rd Quarter Heavy Load Hour ("6x16")	400 MW, 2015-2034
Southern Oregon / Northern California (NOB) 3rd Quarter Heavy Load Hour ("6x16")	100 MW, 2015-2034
Mona 3rd Quarter, Heavy Load Hour (6x16)	300 MW, 2015-2034

Table 1 – Active Trading Hubs in 2015 IRP

As the Company represented, FOTs are proxy resources, assumed to be firm, that represent procurement activity made on an ongoing forward basis to help the Company cover short positions. As proxy resources, FOTs represent a range of purchase transactions types. They are usually standard products, such as heavy load hour (HLH), light load hour (LLH), and super peak hours, and typically rely on standard enabling agreements as a contracting vehicle. FOT prices are determined at the time of the transaction, usually via an exchange or third-party broker, and are based on the then-current forward market price for power.[7]

Regarding the availability of FOTs, PacifiCorp represented that it "develops its FOT limits based upon its active participation in wholesale power markets, its view of physical delivery constraints, market liquidity, and market depth, and with consideration of regional resource supply."[8]

[5] See Order No. 15-184 adopting Staff report in Docket No. UP 315 at http://edocs.puc.state.or.us/efdocs/HAU/up315hau144750.pdf.
[6] Source: Table 6.15 of Volume I of the PacifiCorp 2015 IRP.
[7] See page 128 of Volume I of the PacifiCorp 2015 IRP.
[8] See page 129 of Volume I of the PacifiCorp 2015 IRP.

Staff issued several DRs, included as pages 6 to 12 of Attachment B, to understand the Company's rationale for the assumed FOT limits in the table above, including the reason why the Company did not include FOT limits for other hubs represented in its transmission topology (i.e., Mead, Palo Verde, and Four Corners). From the Company's responses, particularly those to DRs 10 and 12, Staff understands that the hubs for which FOT were assumed are reasonable based on transmission availability and previous transactions.

In the Company's response to Staff DR 11, included as pages 8 and 9 of Attachment B, the Company did not provide any quantitative support for its FOT limits assumptions, but rather provided a qualitative explanation. The Company represented that:

> "*PacifiCorp is an active participant in each of the Front Office Transaction (FOT) markets assumed for the Integrated Resource Plan (IRP). By actively participating in the market, front office personnel charged with managing PacifiCorp's energy and capacity position gain insights on liquidity and the amount of power that is available for purchase for various forward time periods at given price levels.* ***These front office personnel, based on their institutional knowledge of each market, identify FOT limits at levels in which there is high confidence that power can be purchased at the assumed volumes and at the assumed price*** *[emphasis added] tied to PacifiCorp's forward price curve (FPC).*"

Staff issued DR 90 to follow up on PacifiCorp's response to Staff DR 11, requesting that the Company provide and further explain the analysis performed by the front office personnel of PacifiCorp to specifically identify each FOT limit assumed in Table 6.15 of Volume I of the PacifiCorp 2015 IRP. In response to Staff DR 90, included as pages 13 to 15 of Attachment B, The Company responded as follows:

> *"There is no further analysis beyond what the Company has responded in its response to OPUC Data Request 11."*

Staff does not doubt the professional institutional knowledge of PacifiCorp's front office personnel. At the same time, the FOT limit assumptions should be supported quantitatively to provide Staff, intervenors, and ratepayers with assurances that the Company is diligent in its assumptions. The lack of such quantitative assurance does not present a significant red flag in the 2015 IRP, because the Company is not proposing to build a major new generating resource in the next two years that potentially could be covered with FOT transactions. However, a quantitative rationale for this assumption should be included in the next and subsequent IRPs.

Coal Analysis

Order No. 14-252, issued at the conclusion of PacifiCorp's 2013 IRP docket (LC 57), required the Company to determine a set of inter-temporal and fleet trade-off analyses in order to determine the least-cost, least-risk alternatives for compliance with federal regional haze rules.

The Commission explicitly ordered the company to review eight scenarios involving five coal-fired generation plants: Wyodak, and Dave Johnson units 1-4 (see Attachment C for table). In addition, the Commission ordered (Order No. 14-296) that the Company provide an update to their analyses for both Naughton unit 3 and Cholla unit 4 as part of this IRP.

Staff notes that the Company completed all of the required analyses, including PVRR analysis under both a medium and low gas price future.

<u>Wyodak</u>

Current Regional Haze requirement – Installation of an SCR by 2019
PacifiCorp has been granted a judicial stay of the US Environmental Protection Agency (EPA)'s requirement to install a Selective Catalytic Reduction (SCR) system while the Company appeals the EPA decision. A final decision is expected in 2016.

PVRR analysis results
PacifiCorp analyzed eight scenarios involving various compliance alternatives for Wyodak and the four units at Dave Johnston plant. The scenarios studied are shown in Attachment C.

Generally, the Company compared the cost of installing an SCR by the compliance date – the benchmark scenario – with costs to retire the unit early or convert to natural gas fueling. The financial analysis clearly shows that inter-temporal and fleet trade-off compliance alternatives are likely to be lower cost than installation of an SCR in 2019. Customer benefits are maximized when the SCR is avoided altogether, and PacifiCorp will continue to appeal for a reversal of the EPA decision requiring the SCR installation at Wyodak. For the current Action Plan, PacifiCorp is planning no regional-haze required capital expenditures for Wyodak. Staff finds this course of action for Wyodak to be reasonable and low risk.

Dave Johnston Unit 3 (DJ3)
Current Regional Haze requirement – Installation of an SCR by 2019 or shutdown by end of 2027
PacifiCorp is currently appealing this EPA decision. If the Company does not prevail, it will shut the unit down at the end of 2027. If the appeal is granted and the EPA decision is overturned, PacifiCorp will re-evaluate its options concerning DJ3.

PVRR analysis results
Due to the uncertainty and risk represented by the EPA Clean Power Plan, PacifiCorp has adopted a planning assumption that coal plants will retire at the end of their depreciable life. This planning posture alleviates potential stranded capital costs that could be incurred through early closure and is a least-cost option as long as the plant does not require additional emissions-related expenditures for continued operation. The depreciation date for DJ3 in all states but Oregon is 2027 and the Company has committed to this shutdown date if it does not win its appeal against the EPA. Regardless of the outcome of the appeal, PacifiCorp is planning on avoiding the installation of the SCR at DJ3.

Staff believes that shutdown of DJ3 at the end of 2027 is a reasonable and low-risk plan, and that avoidance of the SCR altogether is the most reasonable and cost-effective path forward.

Naughton Unit 3
Current Regional Haze requirement – conversion to natural gas in 2018
EPA has confirmed support of Wyoming's approved alternate compliance approach which will allow Naughton 3 to convert to natural gas firing in 2018.

PVRR analysis results
The Company performed a financial comparison between the conversion and an early retirement of the plant. The up-front capital expense for the conversion is only about 12 percent of the capital cost for a new combined cycle plant. Modeling indicates that an early retirement of the plant would result in the capacity need for a new combined cycle plant, requiring much more capital investment.

As a result, the financial PVRR analysis indicates that the natural gas conversion is the more economical solution than an early retirement. However, Staff notes that the difference between the shutdown case and conversion is relatively small. According to the conversion implementation schedule supplied by the Company, the project implementation is assumed to begin in Q1 of 2017. Staff recommends that the Company re-evaluate these two options for Naughton quarterly throughout 2016 to assure that conversion remains the best option. At present, however, Staff agrees that the gas conversion appears to be a reasonable plan for this unit.

Cholla Unit 4

Current Regional Haze requirement – shutdown in 2017 or conversion in 2018.

PVRR analysis results

The Company considered six scenarios including early retirement in 2017 or 2024, a gas conversion in 2018 or 2025, or installation of a Selective non-Catalytic Reduction system (SNCR). PacifiCorp's analysis shows that installation of an SCR is not a cost effective solution for customers compared to the other compliance alternatives. Customer benefits are maximized when Cholla continues to operate (without an SCR) through 2024 followed by a 2025 gas conversion or shutdown. This later conversion allows the company to avoid liquidated damages from prematurely ended coal contracts and other contractual commitments. The Company notes that existing uncertainty surrounding the 111(d) final rules which might also impact the ultimate decision regarding Cholla. PacifiCorp will continue to pursue a compliance route that completely avoids an SCR. If for any reason a gas conversion proves not possible, the Company's has indicated that a 2024 shutdown is its next viable option.

Staff appreciates the conservative approach to capital expenditures and recognizes avoidance of the SCR altogether as a reasonable and low-cost solution to operating Cholla, with either a 2025 shutdown or a conversion to natural gas.

Review of Supporting Studies

Smart Grid

PacifiCorp is currently researching and implementing a more narrow range of smart grid technologies compared to neighboring utilities. PacifiCorp acknowledges some of the benefits of the smart grid efforts that are currently underway or being planned for, whereas it excludes others that are more widely acknowledged and even demonstrated. In other cases, PacifiCorp is omitting smart grid opportunities partially or altogether. PacifiCorp has set a conservative course to integrating current and future smart grid technologies that delay benefits to ratepayers that could be achieved sooner and that could reduce cost and risk in the company's planning.

Smart grid applications can be broadly split into three categories: a) consumer engagement; b) grid optimization; and c) management of distributed renewable resources. Staff has concerns regarding the Company's programs in all three areas.

Consumer Engagement

Though PacifiCorp's "wattsmart" energy efficiency campaign is robust and likely adequate to meet the utility's ambitious energy efficiency goals described in its 2015 Integrated Resource Plan (IRP), Staff is concerned that other areas of consumer engagement related to smart grid technologies are largely being ignored. Demand response (DR), both voluntary and dispatchable, could provide PacifiCorp additional capacity resources but are not being aggressively pursued. Time-of-use (TOU) tariffs, though available to all customer classes, show only diminutive participation levels. This fact suggests that more or different customer engagement tactics are necessary.

Grid Optimization

PacifiCorp's efforts in grid optimization are active and already demonstrating results, but proactive pursuit is imperative in order to maximize benefits to long-term planning. Projects like dynamic line rating and localized storage coupled with distributed energy resources (DER) have the potential to optimize existing resources thus lowering costs. However, PacifiCorp has yet to acknowledge the full level of benefits that these alternative smart grid technologies offer. Such considerations are lacking, for example, in the application of distributed automation, where PacifiCorp considers only the system-wide benefits and precludes benefits realized locally. Advanced metering infrastructure (AMI) is foundational to many smart grid applications and is becoming more cost-effective over time; however, PacifiCorp has been slow to implement smart metering thereby foregoing many smart grid benefits.

Renewable Generation Management

PacifiCorp's current renewable assets are significant, contributing to a smaller carbon footprint and reduced energy prices for ratepayers as discussed in the company's 2015 Smart Grid Report and IRP. Missing from the discussion are efforts to efficiently and effectively integrate variable, distributed resources. As costs for DERs like residential and commercial solar continue to decrease and policies are implemented that encourage greater adoption, PacifiCorp must be proactive in enabling all classes of its customers in integrating these resources. Doing so can beneficially impact future long-term planning.

Staff is encouraged by the potential benefits of a smart grid which are discussed and identified in the report. However, Staff would like to see more progress in the implementation of projects which can realize these benefits.

Flexible Resource Needs Assessment/Wind Integration Study

Intermittent renewable energy sources have the potential of exhibiting short duration load changes of great magnitude, gaining or losing many megawatts in as little as a few seconds. To better understand the regulated utilities' ability to provide following reserves for these quickly changing sources, the Commission issued a guideline calling for three things: 1) a forecasted demand for flexible capacity; 2) a forecasted supply of flexible capacity for diminishing time ramps; and 3) a consistent evaluation of all flexible resources (including electric vehicles-EVs) for meeting the need.

Appendix F of Volume II presents the results of PacifiCorp's flexibility study. The study does not have the detail of reserve capacity by time frame envisioned by the Commission and expected by Staff. Technically, the Company did meet the OPUC guideline by walking through the three requested steps in order to review flexible capacity on the system but Staff finds the results of the study lacking in that they do not reflect system reserve ramping requirements for various sub-hourly time intervals. Subsequently, since this need is not identified in Step (2) the Company does not address Step (3).

Even though the flexibility study requirement is an outcome of an electric vehicle penetration investigation in Oregon, the goal of this study is not to focus solely on EV impacts to the system (and its future potential for flexible capacity); instead, the study is intended to help quantify the level of sub-hourly reserves needed and available on the system-- both at present and as projected into the future.

Although the flexibility study did not satisfactorily address the issue of forecasted flexible demand, the methodology required to do so was covered in excellent detail in the accompanying Wind Integration Study (WIS). Within the WIS the question of determining ramp reserve is covered in great detail. The determination of sub-hourly ramp reserve in "bins" of different time periods is precisely the kind of analysis that Staff expects to appear in the Flexible Reserves study. Staff expects an analysis that yields similar results but is based on an analysis that uses a projected future with higher renewables penetration than experienced at present.

Essentially the same analysis – determining the level of reserves necessary for reliable system operation – is carried out through three studies – the wind integration study, the flexibility study, and the planning reserve margin study. It may be more practical and, in the end, more comprehensible if the Company were to produce a single reserve study incorporating all the relevant system constraints. The single study could provide the level of contingency reserves, following reserves ("ramp reserves"), and regulating reserves necessary for the planning horizon.

The Flexible Resource Needs Assessment, Planning Margin Reserve Study, Western Resource Adequacy Evaluation, Wind Integration Study and to a lesser extent the Wind and Solar Peak Study and the Energy Storage Study are all related in the sense that they have the goal of optimizing future reserve levels given changing resource and load characteristics. Yet it is not apparent how, or if, the studies inform one another or build off of each other.

Staff believes the goal of these studies, taken as a whole, is to ensure that the system is reliable yet optimized for least cost and risk. The risk factors analyzed in these studies – generation related uncertainty, load uncertainty, emerging changes in demand side practices – are interdependent. For this reason, Staff would like to see a single comprehensive reserve analysis rather than the assembly of individual independent studies.

<u>Planning Reserve Margin (PRM) Study</u>

The PRM study is comprehensive in that it analyzes three reliability metrics (Expected Unserved Energy, Loss of Load Hours and Loss of Load Expectation) over 10 different PRM levels ranging from 10 percent to 20 percent. The Company also provides a reasonable incremental cost calculation to determine the cost of each additional 1 percent of PRM.

Although the study provides a wealth of data to analyze, the Company falls short in quantitatively using the data to choose an appropriate PRM. Instead, the Company offers a one paragraph narrative conclusion in which it contends that the study supports ongoing use of the existing PRM of 13 percent.

Although Staff does not argue that this *may* be a reasonable conclusion, Staff expects a more rigorous analytical approach based on the calculated data in order to reach that conclusion.

Western Resource Adequacy Evaluation

Staff appreciates the inclusion of the Utah required study. Staff is also interested in this forward-looking evaluation of regional generation capacity in light of PacifiCorp's dependence on front office transactions in meeting future load.

Based on the results of this evaluation, Staff is satisfied that sufficient resources exist within the Northwest Power Pool to support PacifiCorp's need for market transactions during the Action Plan timeframe. However, Staff is concerned about the effect of the closure of Portland General Electric's Boardman plant in 2020 and other potential plant closures in WECC due to existing and emerging environmental regulations. The Company should continue to perform an ongoing assessment of the Mid-C market depth in light of these potential changes in resource availability.

Staff recommends that an updated version of this evaluation accompany all future IRPS.

Net metering / Distributed Generation Study

In the Distributed Generation Resource Assessment for Long-Term Planning, residential and commercial solar PV is forecasted to be the dominant net metered resource for the Company, especially past 2022 with 2034 penetration estimated to range from two percent to 21 percent of peak system load. Scenarios S-04 and S-05 introduce a low case of distributed generation future installations and a high case, beyond the base case forecast. In the high case, there is significant benefit to the overall portfolio beyond what is forecasted in the base case. Also of value to note is that the low case increases the portfolio costs by $239M. This is a small amount relative to the total 20 year PVRR of the preferred portfolio but it is more than the difference in costs between top portfolios when choosing which one is preferred. In other words, it appears that any actions to support even the base case forecast of distributed generation coming to fruition would provide benefit to the system.

The distributed generation study notes market barriers to adoption which the Company could play a role in overcoming. Incentive programs help to address the first cost barrier noted in Volume II,

Appendix O study. Perhaps the most effective first step is to offer incentives in Idaho, Washington and Wyoming for residential and commercial solar PV, similar to the Oregon, Utah and California programs.

Participating in advancing interconnection standards in all service area states and two-way controls to familiarize the Company with how to plan and operate the system at growing levels of distributed generation penetration could all be noted in the Action plan.

Staff questions the accuracy of some of the data used in the Oregon distributed generation base case. According to Figure 6-11 of the study, Oregon has what appears to be 2MW of hydro capacity and less than 1 MW of solar in 2013. By 2018, the base case appears to estimate 5-6 MW of net metered hydro and less than 4 MW residential and commercial solar. However, according to Staff's discovery, as of March 2015 PacifiCorp had nearly 9 MW of net metered PV installed through their Volumetric Incentive Rate (VIR) pilot[9] and Energy Trust had over 50 MW across PGE and PAC territory which could conservatively be estimated to be an additional 10 MW in PacifiCorp territory. In addition to that perceived mismatch of existing resources, there is a very conservative forecast for solar PV going forward in Oregon compared to residential wind in Oregon and solar PV in all other states. For example, it appears as though the base case anticipated 5 MW of residential solar in Oregon by 2034 and more than 30 MW in PacifiCorp's California territory.

Staff continues discovery on this issue to better understand the Oregon specific assumptions used.

[9] Order No 15.092

Areas of Staff Concern

After review of the IRP and its associated appendices, Staff has identified several areas of concern in the Company's assumptions and the processing of the portfolio results. In particular, Staff has concerns about:

- The modeling of climate change considerations, especially emerging 111(d) implications
- The ongoing use of derivative metrics to screen out portfolios
- Assumptions and program planning for Demand Response and other demand side management issues
- Financial justification for the Wallula-McNary transmission project
- Potential system constraints regarding winter peak

Climate Change Considerations

PacifiCorp undertook a difficult and complex modeling task of incorporating various 111(d) compliance scenarios as part of their 2015 IRP. These modeling runs were developed with information from the Environmental Protection Agency's (EPA) proposed 111(d) rule, which has undergone considerable change with EPA's August 3rd release of their final 111(d) rule.

However, Staff is concerned that PacifiCorp did subscribe to a singular and overly flexible policy position regarding the treatment of Renewable Energy Credits (RECs) that influenced nearly every modeling run. Staff is interested in PacifiCorp's interpretation of the Renewable Energy Certificate rules in both Washington and Oregon. In particular, it is unclear to Staff how the language of these rules allows PacifiCorp to adopt a position which allows for the separation of a 111(d) attribute from REC resources such that the REC and a 111(d) compliance attribute can be used for separate compliance purposes. Staff requests that PacifiCorp demonstrate how this assumption is not incongruent with the following State rules: Revised Code of Washington Title 19, Chapter 285 (Energy Independence Act), Section 30 (Definitions), (20) "*Renewable Energy Credit, means a tradable certificate or proof of at least one megawatt-hour of an eligible renewable resource where the generation facility is not powered by freshwater. The certificate includes all of the nonpower attributes associated with that one megawatt-hour of electricity, and the certificate is verified by a renewable energy credit tracking system selected by the department.*" and Oregon Administrative Rule 330-160-0015(9) *"Renewable Energy Certificate" (REC* *or Certificate) means a unique representation of the environmental, economic, and social benefits associated with the generation of electricity from renewable energy sources that produce Qualifying Electricity. One Certificate is created in association with the generation of one Megawatt-hour (MWh) of Qualifying Electricity. While a Certificate is always directly associated with the generation of one MWh of electricity, transactions for Certificates may be conducted independently of transactions for the associated electricity."*

Although the 111(d) final rule is different from the proposed rule, the treatment and tracking of RECs is a key issue and one that has changed little from the proposed rule. The REC issue will still affect the Company's 2015 IRP results regarding resource availability, resource procurement, new resource needs and federal regulatory compliance. In the end, Staff is concerned that PacifiCorp's application of state law regarding REC allocations may have resulted in a flawed analysis that does not properly inform the Commission about future cost and risk. That is, had PacifiCorp created a model where REC resources could not be used for different compliance obligations in different States then PacifiCorp would have submitted an IRP that looked more similar to their S-15 sensitivity run. This sensitivity run shows a different set of resources and different assumption regarding shut down dates and the addition of new resources to serve the PAC West system.

Staff understands that the uncertainty and timing of unresolved issues regarding 111(d) and the State's policies regarding its implementation has forced the Company to make certain assumptions in this IRP. Staff expects that the Company will actively reassess these assumptions as relevant policy and legal questions are answered, and that the next IRP update and subsequent IRPs will reflect any changes in the Company's assumptions.

Discussion of PVRR Metrics

PacifiCorp continues to rely upon risk metrics in its best cost/risk portfolio selection process that can be misleading or suffer from an element of arbitrariness. Staff believes the flaws in the metrics could potentially lead to incorrect or inconsistent results. In particular Staff questions: 1) the use of the "Upper-tail Mean PVRR minus Fixed Costs" metric in the portfolio screening process; and 2) the use in final screening of the "risk adjusted PVRR". Below Staff provides examples to illustrate the issue with each of these metrics.

1) Principal Portfolio Selection Pre-Screening and Initial Screening Criterion

The principal criterion that PacifiCorp continues to use in early screening of its portfolios is a combination of each portfolio's: a) stochastic mean present-value-revenue-requirement (PVRR); and b) its upper-tail stochastic mean (using the three highest PVRR outcomes) minus the non-stochastic, System Optimizer-based portfolio fixed costs. (These paired figures are displayed on the graphs on pages 178 through 181 of Volume I of the 2015 IRP.) To make discussing the second metric more manageable it will be abbreviated to "Upper-tail Mean PVRR minus Fixed Costs."

Statistically, minimizing risks and costs means having a low Upper-tail Mean PVRR and low Fixed Costs. The low Fixed Costs can translate to a low Stochastic Mean PVRR, an unambiguously desirable attribute of an attractive portfolio. However, using the "Upper-tail Mean PVRR minus Fixed Costs" as a screening tool—where a low net value is what is sought for— has the unintended consequence that a portfolio with high fixed costs (normally a bad thing) can create a more favorable metric for the portfolio since it is *subtracted* from the PVRR. That is, by using this metric, a portfolio with a high fixed cost appears to be a better performer than a portfolio with lower fixed cost.

The next two evaluation matrices will illustrate how the Upper-tail Mean PVRR minus Fixed Costs screening tool can be misleading, and how that outcome can be avoided. The following *hypothetical* example illustrates the error potential when the portfolios are quite different.

Consider two portfolios, one based on natural gas generation and one based on nuclear generation. Typically, a natural gas portfolio will have relatively low fixed costs but high variable (fuel) costs. Thus, it will have a small fixed cost to subtract from the mean PVRR. On the other hand, the nuclear portfolio has a reverse attribute – very high fixed cost and relatively low variable cost. In the end, though, the mean PVRRs of each portfolio are close.

Assuming the following hypothetical situation, for illustration only,

PACIFICORP EVALUATION MATRIX #1

($\$ \times 10^6$)

Evaluation Criterion	Nat. Gas Portfolio	Nuclear-Heavy Portfolio
Stochastic Mean PVRR	27,500	28,500
Upper-tail Mean PVRR minus Fixed Costs	20,000	15,000

Conclusion from Evaluation Matrix #1:

While the natural gas portfolio has a slight ($1 billion) advantage with regard to the Stochastic Mean PVRR, the nuclear-heavy portfolio has a major advantage ($5 billion) with regard to the second evaluation criterion, Upper-tail PVRR minus Fixed Costs. The implication is that although the nuclear portfolio is slightly more expensive, the savings in risk as revealed by the second criterion should weight the decision toward the nuclear portfolio. If the choice of portfolio is based solely on these criteria, the choice apparently would be to the nuclear portfolio.

Now consider the hypothetical evaluation matrix augmented as follows:

AUGMENTED EVALUATION MATRIX #2

($ x 10^6)

Evaluation Criterion	Nat. Gas Portfolio	Nuclear-Heavy Portfolio
Stochastic Mean PVRR	27,500	28,500
~~Upper-tail Mean PVRR minus Fixed Costs~~	~~20,000~~	~~15,000~~
95th Percentile Stochastic PVRR	31,000	31,500
Fixed Costs	12,000	17,500
Upper-tail Mean PVRR	32,000	32,500

Conclusion from Evaluation Matrix #2:

When comparing the two portfolios on these other criteria, the conclusion is quite different. On all metrics *except the Upper Tail Mean minus Fixed Costs*, the natural gas portfolio proves superior.

It is clear from the previous two examples that reliance on the "Upper Tail Mean minus Fixed Cost" metric could lead one to choose a portfolio that was neither least-cost nor least-risk.

A Note About Risk

Given the conventional risk definition as the degree of variation about the mean, the "Upper-tail PVRR minus Fixed Costs" evaluation criterion constitutes a risk measurement. Under typical regulatory environments, fixed-costs are recoverable through rates and also represent investment that earns shareholder

> *interest. On the other hand, the other component of cost – those variable costs that represent the stochastic portion of the PVRR – represent a cost risk to shareholders, a cost that may be borne by the company. Avoiding a shareholder bias is another argument for insisting that the "Upper-tail PVRR minus Fixed Costs" evaluation criterion not be a principal one. It might be included among the various other criteria, but should not be afforded primary stature.*

Staff recommends that the principal Pre-Screening and Initial Screening criterion should be a combination of each portfolio's Stochastic Mean PVRR and either the 95th Percentile Stochastic PVRR or its Upper-tail Mean PVRR. The use of the "Upper-tail Mean PVRR minus Fixed Costs" as a screening tool should be abandoned as it may produce portfolio decisions that are neither truly least-cost nor least-risk to ratepayers.

<u>2) Final Screening – Risk-adjusted PVRR</u>

"The risk adjusted PVRR is the primary metric used to identify top performing resource portfolios during the final screening step." *See* page 181 of Vol. I. "The risk-adjusted PVRR….is calculated as the PVRR of stochastic mean system variable costs plus five percent of system variable costs from the 95th percentile [PVRR]. The PVRR of system fixed costs, taken from System Optimizer, are then added to this system variable cost metric." *See* page 166 of Vol. I.

Staff has identified two shortcomings of this final screening approach: 1) the five percent risk weighting factor is arbitrary and appears to have no supporting rationale; and 2) it obscures two metrics that best convey risk, i.e., the 95th Percentile Stochastic PVRR and the Upper-tail Mean PVRR. Reliance on the risk adjusted PVRR without a clear review of these other two metrics can lead to choosing a portfolio which is not truly least cost or least risk.

Consider a comparison of two natural gas portfolios

PACIFICORP EVALUATION MATRIX #3

($\$ \times 10^6$)

Evaluation Criterion		Nat. Gas Portfolio A	Nat. Gas Portfolio B
PVRR of Stochastic Mean Variable Costs		15,500	15,500
Five Percent of System Variable Costs from the 95th Percentile PVRR		950	1,275
Fixed Costs PVRR		12,000	11,500
Risk-Adjusted PVRR	(sum of the above)	28,450	28,275

Conclusion from Evaluation Matrix #3:

Natural Gas Portfolio **B** would be selected based upon having the lowest Risk-Adjusted PVRR.

Recall that the “five percent” of system variable costs in item two is chosen arbitrarily. If instead a value of ten percent is used, the results are different.

In the following example, ten percent of the system variable costs are included:

PACIFICORP EVALUATION MATRIX #4

($ x 10^6)

Evaluation Criterion	Nat. Gas Portfolio A	Nat. Gas Portfolio B
PVRR of Stochastic Mean Variable Costs	15,500	15,500
Ten Percent of System Variable Costs		
from the 95th Percentile PVRR	1,900	2,550
Fixed Costs PVRR	12,000	11,500
Risk-Adjusted PVRR	29,400	29,550

Conclusion from Evaluation Matrix #4:

In this case, alternative Natural Gas Portfolio **A** would now be selected based upon now having the lowest Risk-Adjusted PVRR. Placing a heavier emphasis on risk has taken away Portfolio B's Risk-Adjusted PVRR advantage.

Given the sensitivity of PacifiCorp's chosen final screening metric to the risk weighting factor, one may want to look at the relevant underlying figures to assist in portfolio selection. Below is the base set of statistics for the portfolio:

AUGMENTED EVALUATION MATRIX #5

($ x 10^6)

Evaluation Criterion	Nat. Gas Portfolio A	Nat. Gas Portfolio B
Stochastic Mean PVRR	27,500	27,000
95^{th} Percentile Stochastic PVRR	31,000	35,500
Fixed Costs PVRR	12,000	11,500
Upper-tail Mean PVRR	32,000	37,000

Conclusion from Matrix 5:

Recall that PacifiCorp's Risk-Adjusted PVRR metric chose B as the superior portfolio. However, comparison of the two portfolios based on these base metrics may yield a different conclusion. Although Portfolio B has lower fixed costs, and thus a lower stochastic mean PVRR, its much higher costs in the upper tail represent a high risk. In this light, the choice of portfolio may not be clear.

Summary

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.

Demand Response

Staff is concerned that PacifiCorp's IRP shows little potential for demand response (DR) on the western part of its system. The Company's assertion that their residential metering and data-gathering infrastructure is not modern enough to offer or build out demand response as a viable and significant resource on the western portion of its system is troublesome.

Demand response is not a new resource; utilities in Virginia have had DR programs for residential air conditioning since the 1970's, and the city of Milton-Freewater has been operating demand response programs in the Pacific Northwest for decades, a system that does not utilize advance metering infrastructure. Staff is additionally concerned about the Company's lack of demonstrated interest in studying the viability of demand response on the western portion of its system through robust pilot programs. DR has the potential to reduce systems cost and should be explored more thoroughly by the Company.

Demand Side Management/Energy Efficiency

Class 2 DSM

The current IRP's projection of acquiring 2,385 GWh of Class 2 DSM by 2018 represents a large system wide increase in expected cost effective savings from the 2013 IRP (a 37 percent increase). Although comparison data from the last IRP was not available for Oregon resources, this increase for the five other states appears to be due to new opportunities identified in lighting, space and water heating, space cooling, and industrial processes.

Presenting Oregon Class 2 DSM existing and potential resource in a more integrated fashion within the plan for the other five states in the Company's territory would make interpretation of the analysis for efficiency more efficient in future IRPs.

Although Staff understands the complexity in managing multiple diverse programs, there is also likely to be some efficiency and cross-pollinating of beneficial program experiences and findings. To the extent that there are benefits with multiple studies and contractors working across the West, noting how work in other regions has benefited Oregon or vice versa would be helpful to emphasize in future filings.

Staff questions whether the methods used to determine the "nameplate capacity" of Class 2 DSM within the Portfolio Capacity tables is an appropriate and useful way to represent Class 2 DSM and compare resources in a consistent manner. Although footnotes throughout the document explain that the capacity values in the tables are the sum of the non-coincident peak contributions of various savings measures, the result, as explained below, is a somewhat useless value that adds confusion in interpreting the underlying characteristics of each states Class 2 resource.

Staff understands that non-coincident peak hour contributions of efficiency bundles for each state were added together to determine the capacity for each state. The result in adding non coincident peak hour contributions of efficiency bundles into one resource line item leads to very different results than if the state-specific portfolio of Class 2 resource over 8760 hours of the year was first determined and then the peak of that combined portfolio resource was used to select the peak hour savings as the capacity value for that state's portfolio. Breaking apart state capacity values for efficiency into summer and winter Class 2 DSM line items would be more useful.

Staff continues to assess this question of capacity value for projected savings and appreciates the Company's assistance with providing more information.

The Company has been fine-tuning its Class 2 DSM analysis with each IRP. Staff suggests reviewing how measure bundles are assembled in the future, and specifically, recommends defining bundles after adjusting total resource costs for transmission and distribution (T&D) deferral, stochastic risk reduction, and the Northwest Power Act ten percent credit for each measure. The impact of adjusting costs after the measures are bundled and assigning one 8,760 hourly load shape to represent the bundle would lead to assigning an overall bundle T&D value which, as shown in the differences between Table 6.12 and Table 6.13 can cause significant variation in adjustment and may inadvertently over- or under-assess value to specific measures within the bundle. Before continuing with this approach in the next IRP Staff suggests exploring additional options.

Core case C11-01 was developed assuming accelerated acquisition of energy efficiency resources and resulted in a portfolio PVRR nearly identical to core case C05-01. However, C11-01 was not selected for various adjustments like C05-01 was (C05-03, and C05a-03). In each of these adjusted cases, C05-01's PVRR performance was improved upon and ultimately C05a-03 was chosen for risk analysis, and became the preferred portfolio with a final modification to include newly added qualifying facilities (QFs) in the system. As apparent in the table below, although there is additional cost to accelerating DSM, the modeling shows benefit in doing so across the entire portfolio, especially within the first 10 years of the plan.

Class 2 DSM case	Total MWh Class 2 DSM	MWH as % Base	20-yr Class 2 DSM PVRR $M	10-yr Class 2 DSM PVRR $M	20- yr Portfolio PVRR ($M)	10- yr Portfolio PVRR ($M)
Base (preferred portfolio)	2,168,100	100%	$ 101	$ 43	$ 26,340	$ 14,048
Base used for scenarios (C05-1)	2,168,100	100%	$ 101	$ 43	$ 26,353	$ 14,043
Accelerated (C11-1,C11-2)	2,132,570	98%	$ 144	$ 62	$ 26,350	$ 14,027
Adj. Accelerated (removes $1.5m/yr)	2,132,570	98%	$ 129	$ 52	**$ 26,335**	**$ 14,018**
Base + (C03-1)	2,782,200	128%	$ 860	$ 318	$ 28,889	$ 15,008

Table 2 -- Oregon only DSM case comparison

The accelerated DSM case is most in line with the Energy Trust's 2015-2019 Strategic Plan goals. Energy Trust has been very clear that their plan would be a "push" - not easy to achieve costing more per kWh saved - but it would still meet cost effective thresholds. Staff is supportive of maintaining the Base portfolio goals in this IRP but encourages the Company to follow Energy Trust's drive to acquire all cost effective resource and invest in new approaches and emerging technology development throughout its territories to accelerate cost effective achievable energy efficiency. In addition, Staff requests that the Company run the preferred portfolio with the accelerated DSM case for the 2015 IRP Update to help Staff and the Company better understand how accelerated DSM performs under a range of future conditions and system risks than the base case DSM. Accelerating program achievements is not an easy undertaking, but this analysis will help reveal the pros and cons of doing so on a more comparable basis.

Related to the construction of the accelerated DSM case, Staff is looking into the modeled costs per kWh assumptions beyond the short term “acceleration“ phase when identified measures are pushed forward in time with additional costs. Only those “shifted” measures should receive a cost penalty to making the shifting possible but it appears as though costs to acquire future, un-shifted savings in the accelerated case are significantly greater than in the base case. Staff will continue to look into this issue. Upon initial review, it appears as though $1.52 M that is associated with 2015 savings is maintained for every year in the accelerated case, possibly in error. The row labeled “Adj. Accelerated” above removes that fixed $1.52M in years 2016-2034.

Advancing emerging technologies into commercially available resources quickly calls for continued support from the Northwest Energy Efficiency Alliance (NEEA). Incorporating NEEA’s projections for new technology supply into future IRP supply curves more directly would better align the study with current work. For example, it was only in hindsight through a data request from Staff that the Company pulled an emerging technology report for Q1 2015 from NEEA’s website and identified two measures within the AEG study which aligned with NEEA’s emerging technology work.

Class 1 and Class 3 DSM

The action plan includes a Class 1 DSM west-side irrigation load control pilot beginning to 2016 to test the feasibility of program design. No other Class 1 or Class 3 efforts are noted in the action plan. However, there are indications in the modeling analysis work that there could be real benefit to the overall portfolio by increasing the amount of Class 1 and Class 3 resources beyond what is selected in the preferred portfolio.

Wallula to McNary 230-Kilovolt Transmission Line

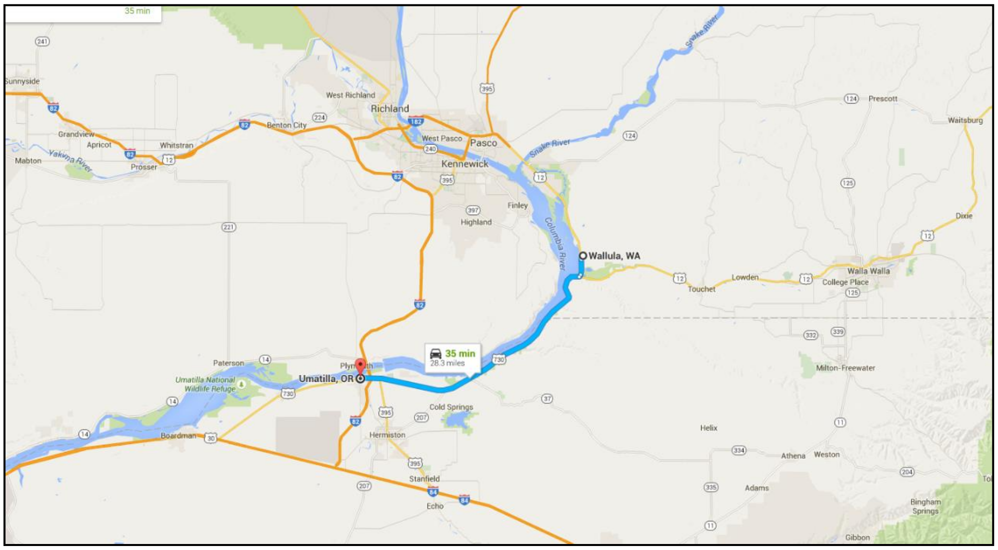
Company’s Request

In its Action Plan for this IRP, PacifiCorp requests acknowledgment for the completion of the Wallula to McNary transmission project in 2017.

Staff Analysis

The Wallula to McNary transmission project consists of approximately 30 miles of single-circuit, 230-kV line between the Wallula, Washington, substation and the McNary, Oregon, substation near Umatilla, Oregon. The project cost is estimated at approximately $30 million.[10] The project's expected in-service date is 2017.[11] Figure 1 shows the project's approximate geographical location and Figure 2 shows its route.

Figure 1[12]

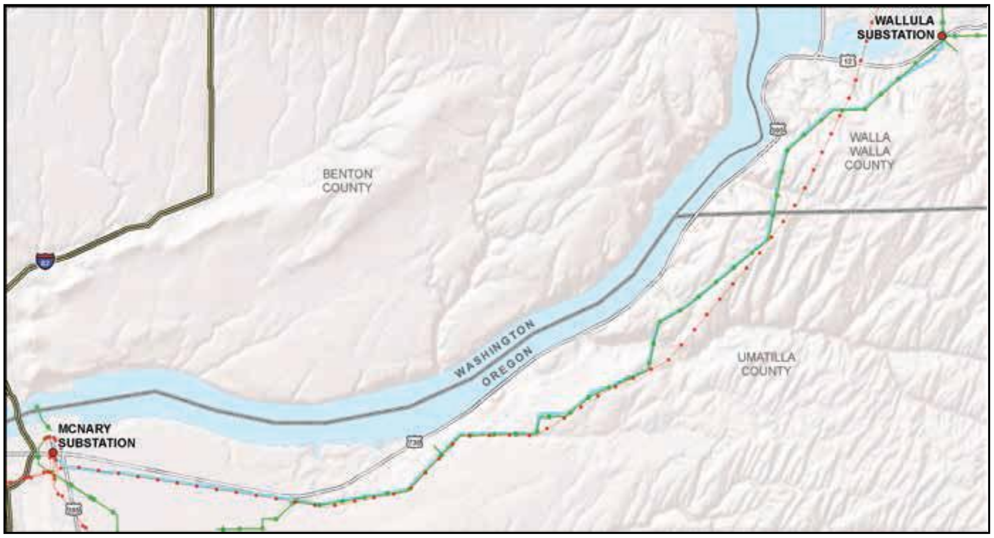


[10] See Docket No. UM1495, Staff 200 Bless/13, lines 17-24, at http://edocs.puc.state.or.us/efdocs/HTB/um1495htb15551.pdf.

[11] See the table provided in page 57 of Volume I of PacifiCorp 2015 IRP.

[12] Source: Google Maps.

Figure 2[13]



In its IRP, PacifiCorp provided a half-page justification for this project. This was corroborated by the Company in response to Staff Data Request 48, which is included in these comments in Attachment B. This justification includes the following:

> "*Factors Supporting Acknowledgment*
>
> ***The key driver supporting PacifiCorp's request for acknowledgment of the Wallula to McNary transmission project is meeting its obligation to its network transmission customers consistent with its OATT*** *[emphasis added]. Without the transmission line, there is no available capacity to serve transmission customers on the existing Wallula to McNary transmission line. This new line will enable the Company to meet its obligation to service transmission customers under the OATT and improve reliability in the area by providing a second connection between Wallula to McNary and a future connection between Walla Walla to McNary (see below Plan to Continue Permitting – Walla Walla to McNary). The transmission line will support future resource growth, including access to renewable energy, and transmission needs."*[14]

Cost-Benefit Analysis

Staff reviewed the economic viability (or "economics") of this project as of two periods of time: (1) as of 2010-2011 ("Dockets UM1495 & LC52 Time Analysis" or "Vintage Analysis") and (2) as of 2015 ("Docket LC62 time analysis" or "Present-day Analysis").

[13] Source: http://www.pacificorp.com/content/dam/pacificorp/doc/Transmission/Transmission_Projects/9776-13_PP_WallulaMcNary_FactSheet_webF3.pdf.
[14] See PacifiCorp 2015 IRP, Volume I, page 49.

Vintage Analysis (Dockets UM1495 & LC52 Time Analysis)[15]

In LC52 (PacifiCorp 2011 IRP), Staff's cost-benefit analysis was based on the one performed by Staff in Docket No. UM 1495 (Certificate of Public Convenience and Necessity [CPCN] for the Wallula to McNary Project).[16] Staff analysis consisted of estimating the project's "economic benefit-cost ratio," which is the quotient produced by dividing the present value of the "net economic benefits" by the present value of "economic costs."

The economic benefit-cost ratio of the Wallula to McNary project was 0.82, which meant that the economic benefits were less than (but relatively close to) the economic costs on a present value basis. Additionally, based on Docket No. UM 1495, in which Staff analyzed the net present value of the revenue requirement (PVRR) under different scenarios regarding initial capital cost and future transmission subscription, Staff provided the following table, which presents the "additional subscription needed" in 2016, 2018, and 2020 for the project to break even. In this context, the breakeven point occurs when transmission revenues cover all costs on a net present basis; therefore, the project has a net revenue requirement of zero when subscription revenues equal annual costs on a net present basis.

Additional Subscription[17] Needed to Reach the Economic Benefit-Cost Ratio of 1.00			
Capital Cost Sensitivities	New Subscription Beginning Years		
	2016	2018	2020
Base Cost	33 MW	38 MW	44 MW
Base Cost Plus 25%	78 MW	90 MW	105 MW
Base Cost Plus 50%	124 MW	145 MW	166 MW

Table 3 - Breakeven Analysis in Dockets LC 52 & UM 1495

[15] For more information about Staff's analysis in Docket No. LC52 (PacifiCorp 2011 IRP), please refer to Staff's final comments in this docket at http://edocs.puc.state.or.us/efdocs/HAC/lc52hac9325.pdf, pages 35 through 39.
[16] Docket No. UM1495 is in the matter of PacifiCorp's Petition for Certificate of Public Convenience and Necessity.
[17] The total capacity of the transmission line is 400 MW.

In Table 3, "Additional subscription needed" refers to those beyond the subscriptions effective as of the time when the subscription of 25 MW from the Eugene Water and Electric Board (EWEB) and 100 MW from NextEra Energy Resources, LLC (NextEra) were active.[18]

Based on Table 3, in Docket No. UM 1495 Staff asserted that "based on a range of scenarios for the cost of the project and utilization of the proposed line, it is likely that the economic benefits of the project will equal the economic cost on a net present value basis."

Finally, in Order No. 11-366 of Docket No. UM 1495, entered on September 22, 2011, the Commission granted a CPCN for the Wallula to McNary transmission line.[19] However, the Commission also stated:

> "*[I]n making this decision, we emphasize that our inquiry and analysis in this case are limited. We are not acting in our traditional ratemaking capacity in this proceeding. As noted above, ORS 758.015 provides this Commission to issue a CPCN to facilitate the condemnation of land necessary for the construction of transmission lines. Thus our decision here is akin to a governmental resolution of necessity to condemn private land. We are granting condemnation authority only.*
>
> *Because we are not pre-approving the M2W Line or making any determinations about future cost recovery, we make no specific conclusions about the effect of the project on Pacific Power's Oregon customers. Contrary to the analysis provided by Pacific Power and Staff, we limit our public interest determination based on the project's cost and benefits to all Oregonians. Whether the M2W Line specifically benefits Pacific Power's customers will be addressed in other proceedings, in which Pacific Power will need to provide additional supporting information.*"[20]

[18] The values of 25MW and 100MW were referenced by the Company in Exhibit PPC/108, Fritz/125 in Docket No. UM1495 at http://edocs.puc.state.or.us/efdocs/HTB/um1495htb9215.pdf.
[19] See page 12 of Order No. 11-366 in Docket No. UM 1495 at http://apps.puc.state.or.us/orders/2011ords/11-366.pdf.
[20] See pages 8 and 9 of Order No. 11-366.

For the Present-day Analysis, Staff has adopted the same approach as in Docket No. LC 52 for the estimation of the "economic benefit-cost ratio". In this IRP, Staff used the updated confidential financial model provided by the Company in response to Staff DR 62 (see Attachment B) and updated the assumptions used in the Dockets UM 1495 and the LC 52 Time Analysis, such as subscriptions effective as of now, the new in-service date of the project, and levels of increased capital costs.

As for the subscriptions effective as of now (i.e., Present-day Analysis or Docket LC 62 Time Analysis), the new model uses only 25 MW of subscription from EWEB instead of the 125 MW of the LC 52 Time Analysis. Per the Company's response to Staff DRs 63 and 52, NextEra and PacifiCorp executed an agreement to facilitate mutual termination of the transmission service agreement, effective December 17, 2013. Additionally a 2017 in-service date has been assumed and the level of capital cost sensitivities (i.e., base capital costs, 25 percent increase, and 50 percent increase) has been maintained.

After updating the aforementioned parameters, the economic benefit-cost ratio of the [redacted]

Additionally, after analyzing the PVRR under different scenarios regarding initial capital cost and future transmission subscription, Staff arrived at the following table, which presents the "additional subscription needed" in 2020, 2022, and 2024 for the project to break even.

Additional Subscription[21] Needed to Reach the Economic Benefit-Cost Ratio of 1.00			
Capital Cost Sensitivitie	New Subscription Beginning Years		
	2020	2022	2024
Base Cost	[redacted]	[redacted]	[redacted]
Base Cost Plus 25%	[redacted]	[redacted]	[redacted]
Base Cost Plus 50%	[redacted]	[redacted]	[redacted]

Table 4: Breakeven Analysis in Docket LC 62

[21] The total capacity of the new transmission line is 400 MW.

Based on scenarios for the cost of the project and utilization of the proposed line, the economic benefits of the project are unlikely to equal the economic cost on a net present value basis due to the fact that NextEra has terminated the agreement for reserving 100 MW, leaving EWEB's agreement for only 25 MW for a 400 MW transmission line.

At present Staff cannot support an acknowledgement of this Action Item with such a poor economic justification.

Winter Peak Constraint

In electrical system planning it is typically assumed that if a utility has sufficient resources to meet its annual peak needs, then any secondary or other season's peak requirements will automatically be met. This is, in fact, how PacifiCorp has approached its analysis of resource needs.

PacifiCorp, whose annual system peak occurs in the summer, also experiences a substantial wintertime peak. Upon close examination of the winter resource needs, it appears that resources designated for meeting PacifiCorp's summertime peak may not be available for meeting the wintertime peak. The Company relies heavily on front office transactions to meet the summer system peak. However, these FOTs are planned only for the third quarter of the year, reflecting a need to meet summer peak. The Company does not similarly identify a large number of first quarter FOTs to meet winter peak. Instead, the Company assumes it will be able to meet the (smaller) winter peak with its own resources.

However, in order to meet the winter peak with its owned resources, the Company must have enough transmission capacity to move the energy between its East and West balancing areas. While as much as 1200 MWs of East/West transfer capability exists in the summer (when the annual system peak occurs), the wintertime East/West transfer capability may be much lower.

In response to discovery on this issue, the Company provided data which indicated that additional FOTs and changes in the timing of future resource acquisitions might be affected by this transmission constraint between east and west balancing areas. Staff continues to investigate this issue.

Concluding Remarks

Taken as a whole, the 2015 IRP presents a rigorous and comprehensive analysis of the Company's future needs to provide reliable service. The processes of forward price forecasting, potential studies discovery and subsequent portfolio development are robust, with a great deal of opportunity for stakeholders to take part.

However, Staff continues to have concerns over some Company planning assumptions, such as those around climate change policy, which have the potential to skew results unrealistically. Staff also continues to object to the use of derivative metrics – specifically the "Upper Tail Mean PVRR minus non-stochastic Fixed Costs" – as an early screening tool. Significant potential exists for unintentionally screening out beneficial portfolios based solely on this metric. Staff is also concerned about the lack of sufficient economic support for the Wallula to McNary transmission line action item.

Despite these shortcomings, the Action Plan developed as a result of the IRP analysis represents a generally reasonable plan for the Action Timeframe. PacifiCorp's Action Plan is both low cost – with no major resource acquisitions and no coal resource expenditures – and low risk in that the Company has chosen a "wait and see" approach to climate-related expenditures. This is a more conservative position than in previous its IRPs.

Staff continues its analysis of the Company's IRP results and Action Plan items and will provide detailed recommendations in Final Comments.

This concludes Staff's Opening Comments.

Dated at Salem, Oregon, this 27th day of August, 2015.

John Crider
Senior Utility Analyst
Energy Resources & Planning Division
(503) 373-1536

Attachment A

Figures 1 - 9

Page 1 of Attachment A (Figure 1 and Figure 2)

Is confidential.

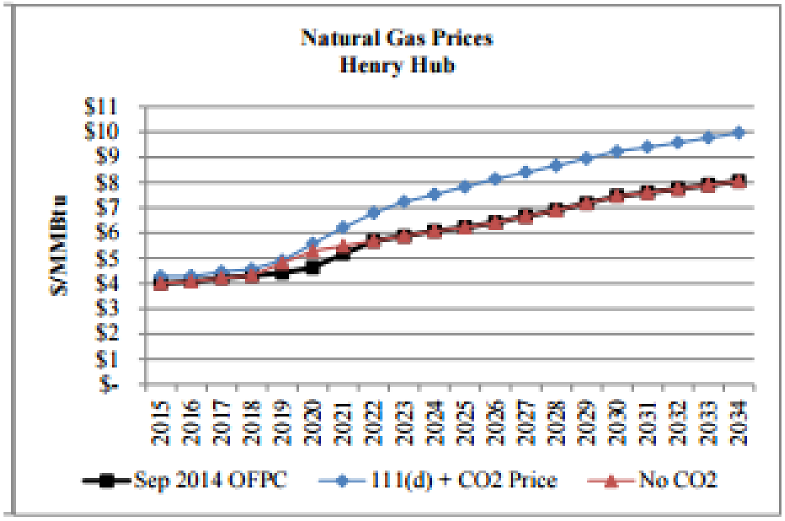


Figure 3--PacifiCorp IRP Page 149 - NG Prices in Core Case Definitions

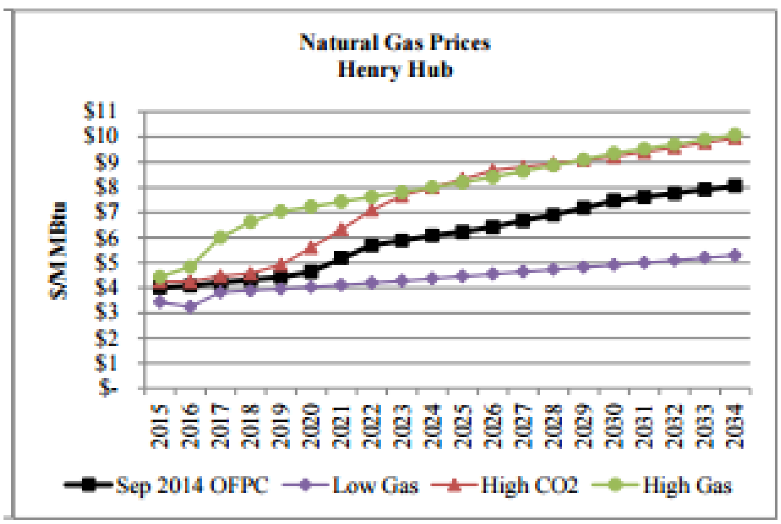


Figure 4--PacifiCorp IRP Page 168 – NG Prices in PaR Simulations

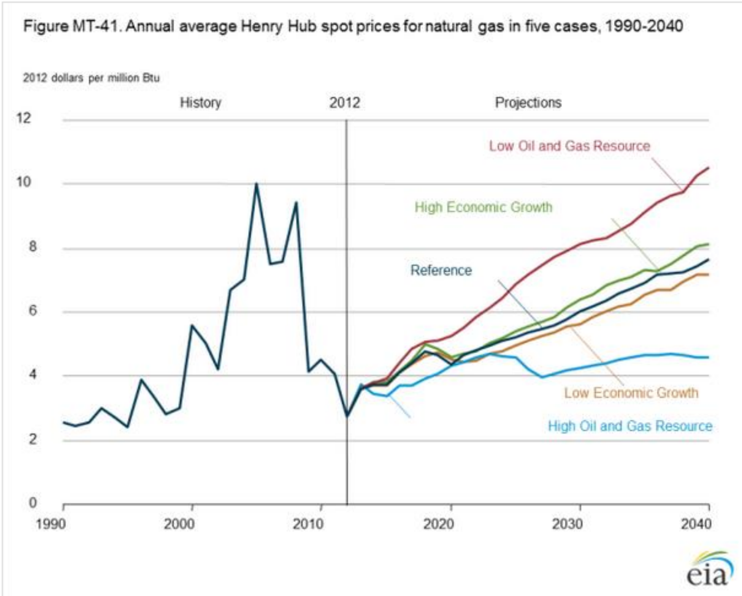


Figure 5 - EIA Annual Energy Outlook 2014 NG Price Forecast (http://www.eia.gov/forecasts/aeo/MT_naturalgas.cfm)

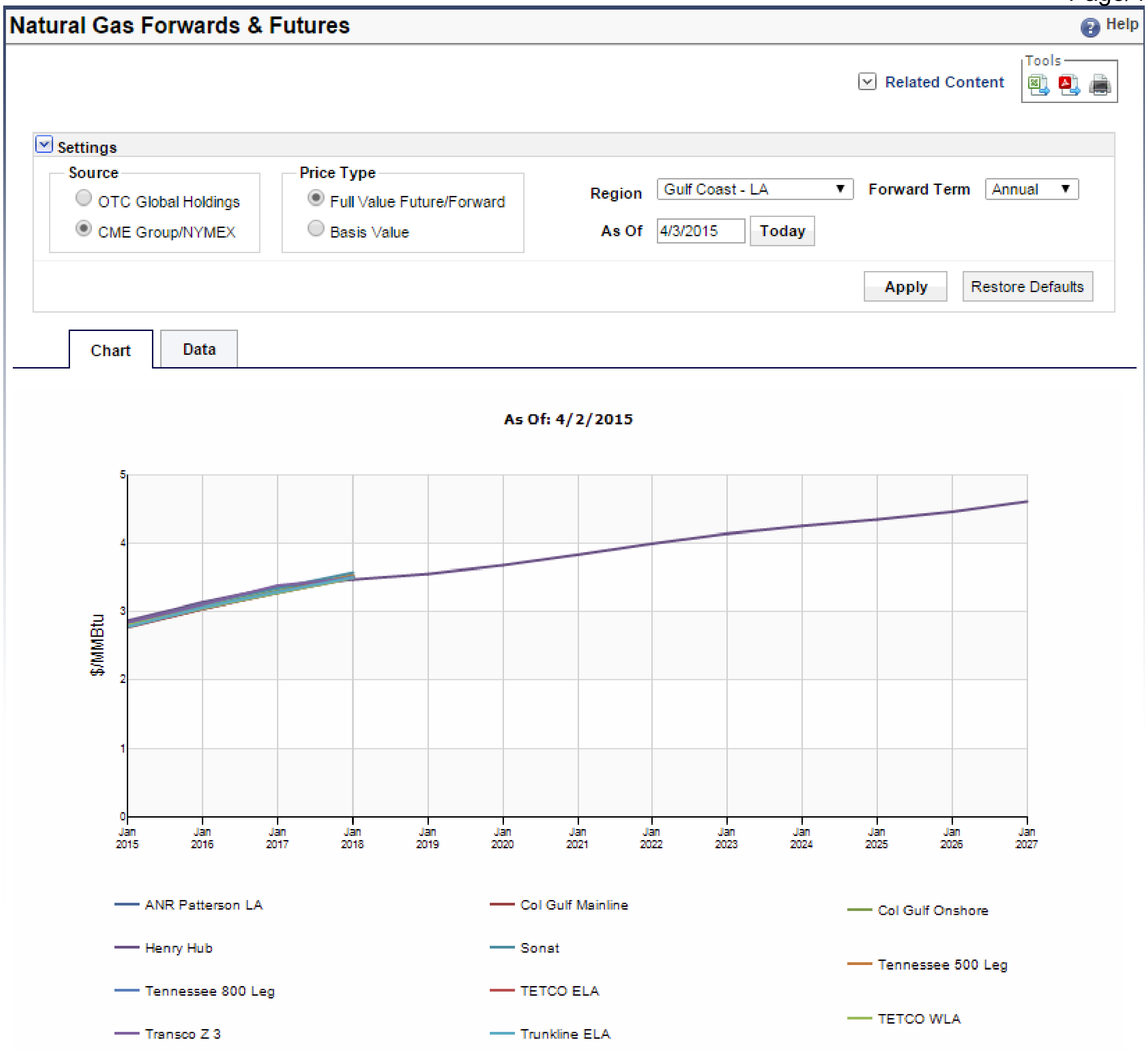


Figure 6 - SNL Natural Gas Future - Part One

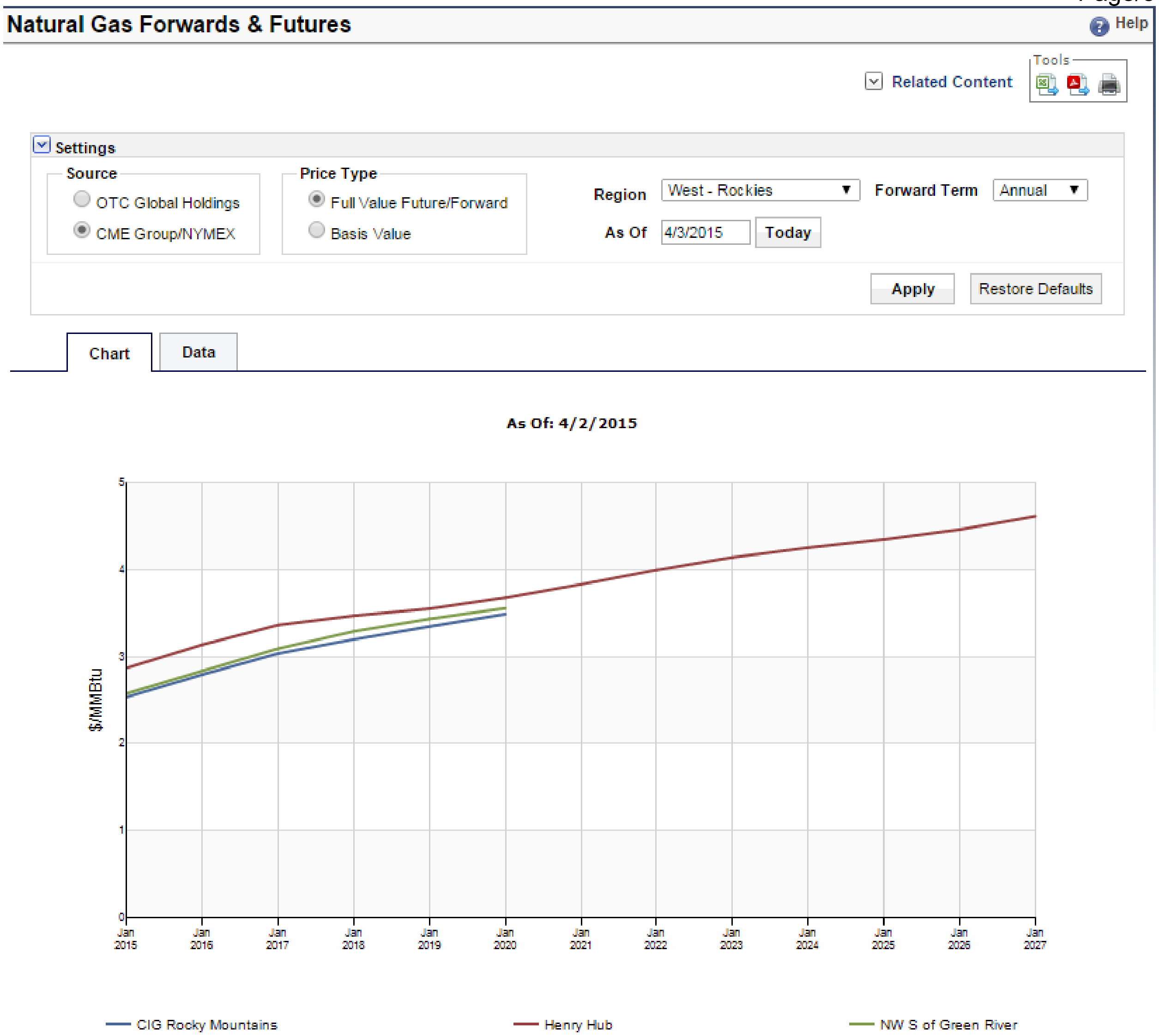


Figure 7 - SNL Natural Gas Forecast, Part Two

SNL data (https://www.snl.com/SNLWebPlatform/Content/Commodities/EnergyMarkets/EnergyMarketsForwardPower.aspx?key=982fafdb-b14f-4c18-b151-75be96d6c2c5&keypage=205228)

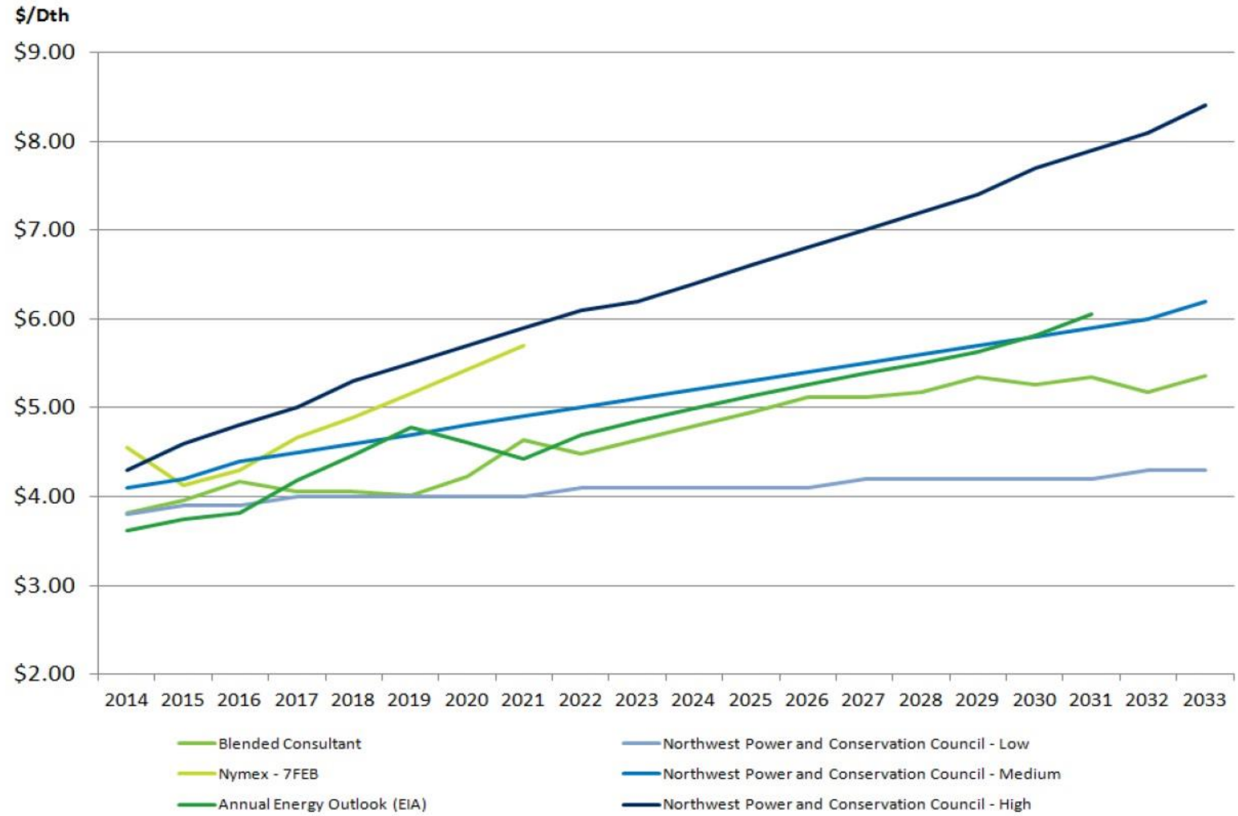


Figure 8 - Avista 2014 IRP NG Price Forecast

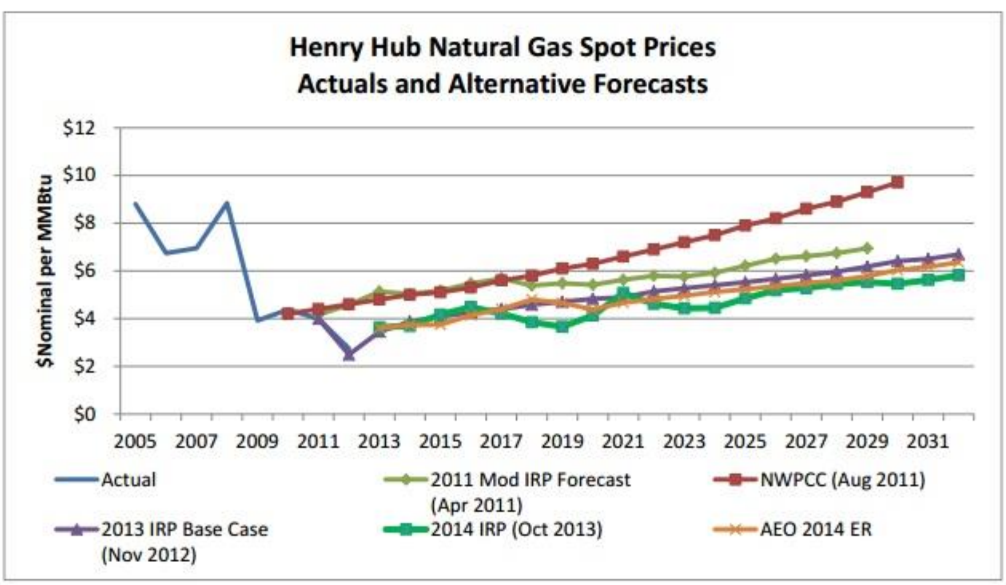
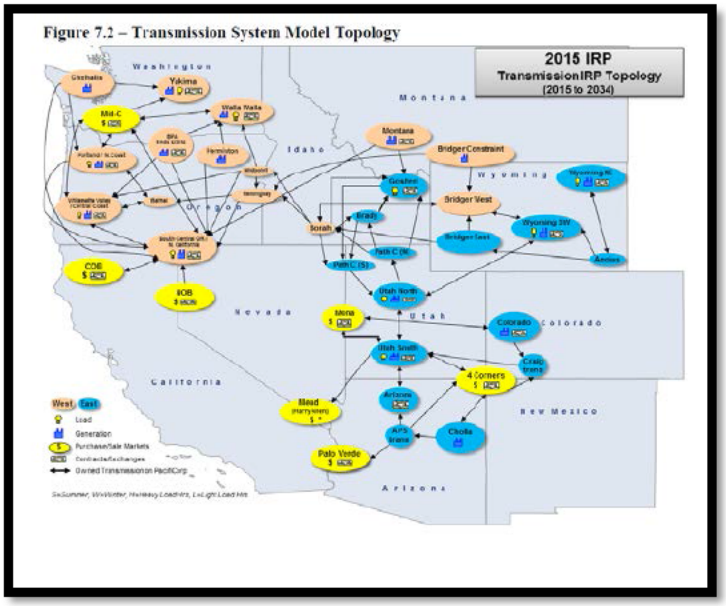


Figure 9 -- Northwest Natural Gas Forecast

OPUC Data Request 7

Chapter 7 – Transmission Modeling and Portfolio Evaluation Approach - Regarding Figure 7.2 of Volume I of PacifiCorp 2015 Integrated Resource Plan (IRP), where the Company provided a figure of the following Transmission System Model Topology:



And,

Regarding page 134 of Volume I of PacifiCorp 2015 IRP, where the Company represented:

> "*PacifiCorp uses a transmission topology that captures major load centers, generation resources, and market hubs interconnected via firm **transmission paths** [emphasis added]. Transfers capabilities across transmission paths are based upon the firm transmission rights of PacifiCorp's merchant function, including transmission rights from PacifiCorp's transmission function and other regional transmission providers.*"

Please:

(a) Provide a list of the **transmission paths** referenced above including each transmission path's transfer capability (if possible, please provide the requested information in a table);

(b) For each **transmission path** provided in part (a) of this data request, please indicate what physical transmission lines are represented by such transmission path. Please provide the most relevant characteristics of the indicated physical transmission lines (e.g., name of the transmission line, voltage, physical transfer capability, rated transfer capability); and

(c) For each **transmission path**'s transfer capability provided in part (a) of this data request, please provide an explanation of how such transfer capability was estimated, including the amounts of, for example, the transmission rights of PacifiCorp's merchant function, the transmission rights of PacifiCorp's transmission function, the transmission rights of other regional providers, etc.;

Response to OPUC Data Request 7

(a) Please refer to the confidential data disks that accompanied the Company's 2015 Integrated Resource Plan (IRP), filed with the Public Utility Commission of Oregon (OPUC) on March 31, 2015; specifically:

Disk 3_CONF\Assumptions-Inputs\Assumptions-Inputs-Transmission, CONF.zip
File: "IRP Base Case, EG 1 - Transmission Path Breakdown.xlsx"

(b) Please refer to Confidential Attachment OPUC 7.

(c) Each transmission path's transfer capability provided in the Company's response to subpart (a) above is based upon PacifiCorp's merchant function's purchased or allocated transmission rights from transmission providers unless:

1. noted otherwise in column K of the file referenced in the Company's response to subpart (a) above, or

2. is a projected allocation from future Energy Gateway transmission projects as noted in column C (column C provides reservation numbers associated with the transmission rights the Company's merchant function owns).

Transmission capacity is purchased or allocated via various agreement types as noted in column J from a number of providers including; PacifiCorp Transmission, Arizona Public Service (APS), Bonneville Power Administration (BPA), Idaho Power Company (IPC), Western Area Power Authority (WAPA), Platte River Power Authority, and Deseret Generation & Transmission Cooperative (DG&T). For each point of receipt (POR) and point of delivery (POD) combination the owned/allocated capacity represented by each reservation/legacy description less applicable derates, such as transfer capacity withheld to serve operating reserves, are summed to achieve the path rating.

The confidential attachments are designated as confidential under Order No. 14-416 and may only be disclosed to qualified persons as defined in that order.

OPUC Data Request 8

Chapter 7 – Transmission Modeling and Portfolio Evaluation Approach - Regarding page 135 of Volume I of PacifiCorp 2015 IRP, where the Company represented:

> "*In developing resource portfolios for the 2015 IRP, PacifiCorp includes estimated* ***transmission integration*** *[emphasis added] and* ***transmission reinforcements*** *[emphasis added] costs specific to each resource portfolio. These costs are influenced by the type, timing, and location of new resources as well as any assumed resource retirements, as applicable, in any given portfolio.*"

And,

Regarding Appendix M of Volume II of PacifiCorp 2015 IRP, where the Company presented **transmission integration** and **transmission upgrade** costs for each of the core cases and sensitivity cases (For instance; Core Case C14-2 includes $230 million of transmission integration costs and $13 million of transmission reinforcement costs; Sensitivity Case S-03 includes $175 million of transmission integration costs and $6 million of transmission reinforcement costs);

Please:

(a) Define the terms "**transmission integration**," **transmission reinforcement**," and "**transmission upgrade**" referred to above and provide an explanation of the differences among such terms;

(b) For <u>each</u> core case and sensitivity case provided in Appendix M of Volume II of PacifiCorp 2015 IRP, please:

i. Provide a description of the <u>specific</u> transmission integration, transmission reinforcements, and transmission upgrades included for such case; and

ii. Provide an explanation of how the costs of such <u>specific</u> transmission integration, transmission reinforcements, and transmission upgrades were estimated; please include work papers used to estimate the requested costs in electronic spreadsheet format with cell references and formulae intact.

Response to OPUC Data Request 8

(a) "**Transmission integration**" refers to the transmission line and substation costs associated with integrating new resources. "**Transmission reinforcement**" refers to the transmission line and substation costs associated with changes to the transmission system. An example of reinforcement would be the costs required to reinforce the transmission system when a resource is retired and reactive power support is needed in the local area. "**Transmission upgrade**" would be the same definition as transmission reinforcement unless the context of the sentence was intended to cover both integration and reinforcement.

(b)

i. Please refer to the confidential data disks that accompanied the Company's 2015 Integrated Resource Plan (IRP), filed with the Public Utility Commission of Oregon (OPUC) on March 31, 2015; specifically:

   Disk 3_CONF\Assumptions-Inputs\Assumptions-Inputs-SSR_CONF.zip\SSR, CONF\ IRP Transmission_Integration Costs.xlsx, which provides generic assumptions of the transmission integration costs.

   Disk 3_CONF\Assumptions-Inputs\Assumptions-Inputs-Transmission, CONF.zip\Transmission, CONF\ Final Transmission Integration Cost for 2015 IRP Studies.xlsx, which provides case specific adjustments from the generic assumptions.

ii. Please refer to Confidential Attachment OPUC 8 which includes the following confidential files related to how the costs were estimated:

   - "PACW – Cost for new resources addition,"
   - "PACE – Cost for new resources addition," and
   - "Reinforcement costs for resource retirements."

The confidential attachment is designated as confidential under Order No. 14-416 and may only be disclosed to qualified persons as defined in that order.

OPUC Data Request 75

Regarding part "b" of PacifiCorp response to Staff Data Request 16, where the Company represented:

> "*Today (pre-transaction in Docket UP 315) under the Legacy Agreements, the Company is allowed 1,600 MW of transmission service, of which up to 200 MW could be dynamically scheduled on a specific 200 MW Idaho Power Company (IPC) Open Access Transmission Tariff (OATT) Point to Point (PTP) service as a component of the Integrated Resource Plan (IRP) Borah – Hemingway path (IPCO Reservation #76955917). Post-transaction in Docket UP 315, the Company will retain 1,600 MW of transmission service comprising 1.090 MW of ownership rights, plus 510 MW of firm IPC OATT service, of which up to 400MW could be dynamically scheduled on either the 1.090 MW of PacifiCorp owned rights of the 510 MW of IPC OATT service."*

Please respond to the following questions:

(a) Has the Company modeled this increased dynamic transfer capability of 400 MW resulting from the transaction in Docket No. UP 315 in its 2015 IRP for the period beginning in 2015 and ending in 2034?

(b) If the response to part "a" of this data request is "yes," please explain how the Company modeled such increased dynamic transfer capability and indicate specifically in which file, spreadsheet, etc. such assumption is located (e.g., Disk 3_CONF\Assumptions-Inputs\Assumptions-Inputs-Transmission, CONF.zip File: "IRP Base Case, EG 1 - Transmission Path Breakdown.xlsx"); and

(c) If the response to subpart (a) of this data request is "no," please explain why not.

R**esponse to OPUC Data Request 75**

(a) No.

(b) Please refer to the Company's response to subpart (a) above.

(c) Resources modeled in the Company's Integrated Resource Plan (IRP) are either owned or under contract. The change in transmission rights were not certain at the time transmission topology inputs for the 2015 IRP were locked down.

OPUC Data Request 10

Chapter 7 – Front Office Transactions (FOT) in Modeling and Portfolio Evaluation Approach - Regarding Table 6.15 of Volume I of PacifiCorp 2015 IRP, where the Company provided the following table with information of the Maximum Available FOT Quantity by Market Hub:

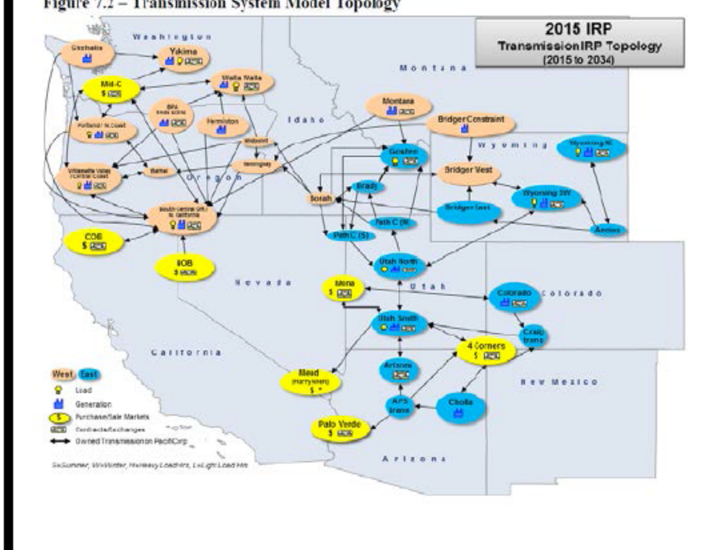
Table 6.15 – Maximum Available Front Office Transaction Quantity by Market Hub

Market Hub/Proxy FOT Product Type	Megawatt Limit and Availability
Mid-Columbia Flat Annual ("7x24") and 3rd Quarter Heavy Load Hour ("6x16")	400 MW + 375 MW with 10% price premium, 2015-2034
California Oregon Border (COB) Flat Annual ("7x24") and 3rd Quarter Heavy Load Hour ("6x16")	400 MW, 2015-2034
Southern Oregon / Northern California (NOB) 3rd Quarter Heavy Load Hour ("6x16")	100 MW, 2015-2034
Mona 3rd Quarter, Heavy Load Hour (6x16)	300 MW, 2015-2034

And,

Regarding Figure 7.2 of Volume I of PacifiCorp 2015 Integrated Resource Plan (IRP), where the Company provided a figure of the following Transmission System Model Topology:

Figure 7.2 – Transmission System Model Topology



Please respond to the following questions:

(a) Has the Company assumed maximum available FOTs for the hubs other than the hubs represented in Table 6.15 above? By "other hubs," Staff refers to the hubs represented in the above Transmission System Model Topology figure such as Mead, Palo Verde, 4 Corners. If "yes," please provide the maximum available FOT transaction quantities for such other hubs; if "no," please provide a comprehensive explanation of the Company's response, including an explanation of why such other hubs were modeled in the Transmission System Model Topology; and

(b) If the Company has engaged historically in FOT transactions in the Mead, Palo Verde, and 4 Corners hubs as requested in parts "a" and "b" of data request 12, please explain what was the Company's assumption of FOT transaction availability from 2015 to the end of the evaluation period in the PacifiCorp 2015 IRP.

Response to OPUC Data Request 10

(a) Front Office Transactions (FOT) are not included at Mead, Palo Verde (PV), and Four Corners (4C) due to transmission constraints. These market locations are included to reflect system balancing transactions.

(b) The limits of FOTs at various hubs are not solely determined based on whether the Company has executed transactions historically. Please refer to the Company's response to OPUC Data Request 11.

OPUC Data Request 11

Chapter 7 – Front Office Transactions (FOT) in Modeling and Portfolio Evaluation Approach - Regarding page 129 of Volume I of PacifiCorp 2015 IRP, where the Company represented:

> "*PacifiCorp develops its FOT limits based upon [1)] its active participation in wholesale power markets, [2)] its view of physical delivery constraints, [2) its view of] market liquidity and [3) its view of] market depth, and [4)] with consideration of regional resource supply.*"

And,

Regarding Table 6.15 of Volume I of PacifiCorp 2015 IRP, where the Company provided the following table with information of the Maximum Available FOT Quantity by Market Hub:

Table 6.15 – Maximum Available Front Office Transaction Quantity by Market Hub

Market Hub/Proxy FOT Product Type	Megawatt Limit and Availability
Mid-Columbia Flat Annual ("7x24") and 3rd Quarter Heavy Load Hour ("6x16")	400 MW + 375 MW with 10% price premium, 2015-2034
California Oregon Border (COB) Flat Annual ("7x24") and 3rd Quarter Heavy Load Hour ("6x16")	400 MW, 2015-2034
Southern Oregon / Northern California (NOB) 3rd Quarter Heavy Load Hour ("6x16")	100 MW, 2015-2034
Mona 3rd Quarter, Heavy Load Hour (6x16)	300 MW, 2015-2034

For <u>each</u> Maximum Available FOT Quantity by Market Hub provide in the table above, please provide a comprehensive justification of such assumed maximum quantity from the perspective of PacifiCorp's:

(a) Active participation in wholesale power markets;

(b) View of physical delivery constraints;

(c) View of market liquidity;

(d) View of market depth; and

(e) Consideration of regional resource supply.

If the Company relied on information sources to formulate the responses to the above question and sub-questions, please identify each such specific source and provide a copy of each such specific source document in portable document format (PDF) file(s), MS Word file(s), Excel workbook (with cell references and formulae intact) file(s), or any other common document format indicating the specific page, section, etc. of the relevant source document.

Response to OPUC Data Request 11

PacifiCorp is an active participant in each of the Front Office Transaction (FOT) markets assumed for the Integrated Resource Plan (IRP). By actively participating in the market, front office personnel charged with managing PacifiCorp's energy and capacity position gain insights on liquidity and the amount of power that is available for purchase for various forward time periods at given price levels. These front office personnel, based on their institutional knowledge of each market, identify FOT limits at levels in which there is high confidence that power can be purchased at the assumed volumes and at the assumed price tied to PacifiCorp's forward price curve (FPC). In making this determination, front office personnel considers that FOT purchases need not be made all at once, which could adversely influence price when soliciting offers. Rather FOT purchases are routinely made in smaller volumetric increments prior to the delivery period. Some of the characteristics that differentiate FOT limits among markets include:

- Mid-Columbia (Mid-C) is one of the most liquid and deep markets in which PacifiCorp actively participates. Underlying this market are numerous hydro generating plants that provide significant levels of physical supply to the region. This is the primary reason why FOT limits at Mid-C are the highest among the FOT markets as assumed for the IRP.

- Comparatively, the California-Oregon Border (COB) has less liquidity and less market depth than Mid-C; however, there is sufficient market activity to support the FOT limits assumed. There is less local supply at COB relative to Mid-C; however, there is significant transmission linking physical supply from the northwest and California to the COB market.

- Comparatively, Mona is less liquid than both Mid-C and COB, and FOT limits are also comparatively lower. Local physical supply includes the 200 megawatts (MW) West Valley plant located in Salt Lake City. Physical supply can also be drawn in from California.

- Among all of the FOT markets assumed for the IRP, the Nevada-Oregon Border (NOB) is least liquid. PacifiCorp has 200 MW of transmission from NOB, which is frequently used for balancing the system on a real time basis. PacifiCorp assumes up to 100 MW of purchases can be made at NOB on a short-term firm (STF) basis.

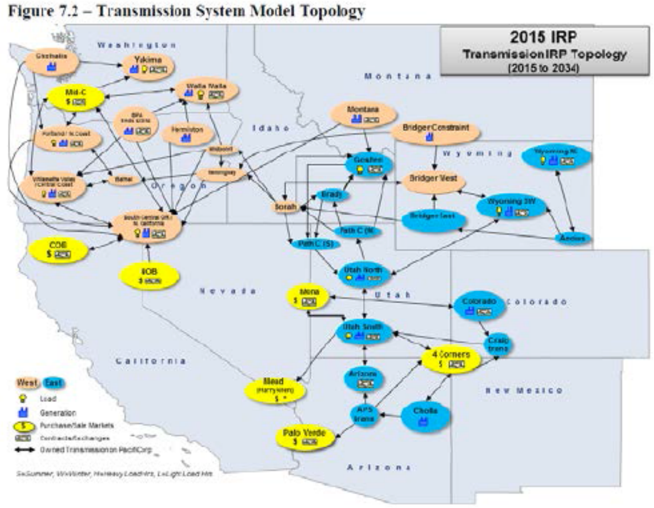
PacifiCorp further monitors regional supply to ensure that its FOT assumptions are not misaligned with physical supply resources over time. Please refer to Appendix J of Volume II to the Company's 2015 IRP for Western Resource Adequacy Evaluation.

OPUC Data Request 12

Chapter 7 – Front Office Transactions (FOT) in Modeling and Portfolio Evaluation Approach - Regarding page 134 of Volume I of PacifiCorp 2015 IRP, where the Company represented:

> "*PacifiCorp uses a transmission topology that captures major load centers, generation resources, and* ***market hubs*** *[emphasis added] interconnected via firm transmission paths. Transfers capabilities across transmission paths are based upon the firm transmission rights of PacifiCorp's merchant function, including transmission rights from PacifiCorp's transmission function and other regional transmission providers. Figure 7.2 [below] shows the 2015 IRP transmission system model topology:*"

Figure 7.2 – Transmission System Model Topology



For <u>each</u> market hub referred to above (i.e., Mid-C, COB, NOB, Mona, Mead, Palo Verde, and 4 Corners), please provide:

(a) The actual energy amounts in MWh of FOTs for each month beginning in January 2010 through December 2014;

(b) The maximum amount of FOTs in one hour for each month beginning in January 2010 through December 2014;

Response to OPUC Data Request 12

(a) Historical data is not modeled in the Integrated Resource Plan (IRP) studies. Please refer to Confidential Attachment OPUC 12 -1, which provides short-term firm (STF) market purchases that were one month or longer in duration and Confidential Attachment OPUC 12 -2, which provides STF market purchases that were shorter than one month. The transactions were for deliveries in January 2010 through December 2014.

For the definition of Front Office Transactions (FOT) and types of FOTs modeled in the IRP, please refer to Volume I of the Company's 2015 IRP; specifically page 128-129. In the Company's actual operations, FOTs generally encompass all STF market purchases to balance its system. For modeling purposes in the IRP, the Company limited such resources to heavy-load-hour (HLH) products during the entire third quarter (Q3) and additional annual flat products on the west side of the Company's system, which are for purpose of meeting capacity needs. Under this assumption, all other firm market purchases may be considered "spot" or "system balancing" transactions in the context of modeling in the IRP.

In Confidential Attachment OPUC 12 -1 and Confidential Attachment OPUC 12 -2, the column titled "DELIVERYPATTERN" or "product_name" may be used to identify delivery pattern:

Product	Description
6 x 16 / 7 to 22 West 1 x 16 (7-22) 6 x 16 (7-22)	On-peak Pacific Prevailing Time (PPT)
6 x 8 / 1 x 24 Mountain 6 x 8 + 24 (24-7)	Off-peak Mountain Prevailing Time (MPT)
6 x 8 / 1 x 24 West 6 x 8 + 24 (23-6)	Off-peak Pacific Prevailing Time (PPT)
7 x 24 Mountain	Around the Clock Mountain Prevailing Time (MPT)
7 x 24 West	Around the Clock Pacific Prevailing Time (PPT)
7 x 8 / 1 - 6, 23, 24 West 7 x 8 (23-6)	Graveyard Pacific Prevailing Time (PPT)
ATC Mountain	Around the Clock Mountain Prevailing Time (MPT)
ATC West	Around the Clock Pacific Prevailing Time (PPT)
Custom	Custom (allows for non-standard transaction delivery pattern)
Hourly Spot	Hourly transactions
Realtime MPT	Hourly transactions
Realtime PPT	Hourly transactions
Shoulder PPT	Hour Ending 7-12 and 21-22 Pacific Prevailing Time (PPT)
Sun Off-Peak West (1-6, 23, 24)	Sunday-only Off-Peak Pacific Prevailing Time (PPT)
Super Peak Mtn (14 - 21)	Super-Peak (hour ending 14-21) Mountain Prevailing Time (MPT)

Product	Description
Super Peak West (13 - 20) 6 x 8 (13-20)	Super-Peak (hour ending 13-20) Pacific Prevailing Time (PPT)

(b) The capacity or maximum amount of transaction in one hour is not readily available. However, for transactions that were one month or longer in duration, such information may be derived from delivery rate of the transactions. Please refer to Confidential Attachment OPUC 12 -1; specifically the column entitled “DeliveryRate” for maximum amount of each transaction.

The confidential attachments are designated as confidential under Order No. 14-416 and may only be disclosed to qualified persons as defined in that order.

OPUC Data Request 90

Regarding the Company's response to Staff data request 11, where the Company represented:

> *"PacifiCorp is an active participant in each of the Front Office Transaction (FOT) markets assumed for the Integrated Resource Plan (IRP). By actively participating in the market, front office personnel charged with managing PacifiCorp's energy and capacity position gain insights on liquidity and the amount of power that is available for purchase for various forward time periods at given price levels.* ***These front office personnel, based on their institutional knowledge of each market, identify FOT limits at levels in which there is high confidence that power can be purchased at the assumed volumes and at the assumed price [emphasis added]*** *tied to PacifiCorp's forward price curve (FPC)."*

And,

Regarding Table 6.15 of Volume I of PacifiCorp 2015 IRP, where the Company provided the following table with information of the Maximum Available FOT Quantity by Market Hub:

Table 6.15 – Maximum Available Front Office Transaction Quantity by Market Hub

Market Hub/Proxy FOT Product Type	Megawatt Limit and Availability
Mid-Columbia Flat Annual ("7x24") and 3rd Quarter Heavy Load Hour ("6x16")	400 MW + 375 MW with 10% price premium, 2015-2034
California Oregon Border (COB) Flat Annual ("7x24") and 3rd Quarter Heavy Load Hour ("6x16")	400 MW, 2015-2034
Southern Oregon / Northern California (NOB) 3rd Quarter Heavy Load Hour ("6x16")	100 MW, 2015-2034
Mona 3rd Quarter, Heavy Load Hour (6x16)	300 MW, 2015-2034

Please respond the following questions:

(a) Please describe in detail the analyses made by the front office personnel of PacifiCorp to specifically identify each FOT limit provided in the above table and provide any supporting documentation for the analyses; and

(b) Please fill in the table for data spanning 2010-2015. Enter into the table the amounts representing the **maximum traded volume** and the **average traded volume** (MWh) on a monthly basis.

Month	MidC		COB		NOB		Mona		Sum	
	Max	Avg	Max	Avg	Max	Avg	Max	Avg	Max	Avg
Jan										
Feb										
Mar										
Apr										
May										
June										
July										
Aug										
Sept										
Oct										
Nov										
Dec										
Sum										

Response to OPUC Data Request 90

(a) Through active participation in the markets with brokers, the Company's front office personnel learn about availability of power in the markets, including when it will be available and how much is available. The information from brokers may be delivered through phone conversations or publications, such as the settled amount of transactions published by the Intercontinental Exchange Inc., at https://www.theice.com/[1]. There is no further analysis beyond what the Company has responded in its response to OPUC Data Request 11.

(b) The requested information for 2010 through 2014 may be obtained from the Company's response to OPUC Data Request 12, specifically Confidential Attachment OPUC 12 -1 and Confidential Attachment OPUC 12 -2. For actual transactions from January 2015 through June 2015, please refer to Confidential Attachment OPUC 90.

Below is a mapping between the requested information categories and column titles in the attachments:

Category	Column Title	
	Confidential Attachment OPUC 12 -1	**Confidential Attachment OPUC 12 -2**
Traded volume (megawatt-hours (MWh))	MWh	Total on tabs "2012" and "2014" MWh on other tabs
Month	HRMONTH on tab "2010" month on other tabs	HRMONTH on tab "2010" month on other tabs
Delivery Locations	POD, for tab "2010," por_location_name on other tabs	POD, for tab "2010" por_location_name on other tabs

[1] Information is proprietary and requires subscription.

The mapping between the requested delivery locations and entries in columns point of delivery (POD) and "por_location_name" in the attachments is as follows:

Market	**Confidential Attachment OPUC 12 -1**	**Confidential Attachment OPUC 12 -2**
Mid-Columbia (Mid-C)	MID-C MIDC Market	MID-C MIDC (AVAT) POR/POD MIDC (DOPD) POR/POD MIDC (GCPD) POR/POD MIDC (MHUB) POR/POD MIDC (PGE) POR/POD MIDC (PPW) POR/POD MIDC (PSEI) POR/POD MIDC IOPT NODE MIDC Market MIDCRemote (AVAT) POR/POD MIDCRemote (BPAT) POR/POD MIDCRemote (PGE) POR/POD MIDCRemote (PSEI) POR/POD
California-Oregon Border (COB)	COB N-S	COB COB Market COB N-S COB S-N COBH (BPAT) POR/POD
Nevada-Oregon Border (NOB)		NOB NOB (BPAT) POR/POD NOB (CISO) POR/POD
Mona	MONA MONA Market	MONA MONA (PASA) POR/POD MONA Market

The confidential attachment is designated as confidential under Order No. 14-416 and may only be disclosed to qualified persons as defined in that order.

OPUC Data Request 48

Regarding the two paragraphs in page 49 of volume I of PacifiCorp 2015 IRP, where the Company specifically provided information about its request for acknowledgement of the new Wallula to McNary transmission line (New Wallula to McNary Transmission Line), please explain whether, in addition to such two paragraphs, the Company has provided more information justifying the New Wallula to McNary Transmission Line within its PacifiCorp 2015 IRP filing (e.g., other chapters among Volume I, Volume II, etc.) including financial analyses, investment appraisal documents, core cases' runs, sensitivity cases' runs, etc. Please indicate such additional information is located within its PacifiCorp 2015 IRP.

Response to OPUC Data Request 48

No additional data has been provided within PacifiCorp's 2015 Integrated Resource Plan.

OPUC Data Request 62

Regarding the Company-provided financial model that Commission Staff used in Docket No. UM1495[1] (2011 Financial Model),[2] please respond to the following questions:

(a) Please provide such 2011 Financial Model in electronic spreadsheet format with cell references and formulae intact;

(b) Has the Company updated the 2011 Financial Model since the time it was provided to Staff in Docket No. UM1495 to the present time with new assumptions based on new developments that transpired in that time period? If the Company's response is "yes," please explain and provide such updated financial models in electronic spreadsheet format with cell references and formulae intact including a detailed description of the new modeling assumptions (e.g., new customers contribution to revenue requirement including new date of such customers starting receiving transmission services, fewer transmission customers, new transmission rates for revenues, new transmission costs, etc.). If the Company response is "no," please:

i. Explain why "not"; and

ii. Please provide an updated model with the new assumptions based on the new developments that transpired until the date of responding this data request;

Response to OPUC Data Request 62

Please refer to Confidential Attachment OPUC 62 which contains the following information:

(a) The 2011 Financial Model in electronic spreadsheet format with cell references and formulae intact is provided as "Wallula_McNary_ER3_12409_GM";

(b) The most recent Financial Model in electronic spreadsheet format with cell references and formulae intact is provided as "Wallula – McNary GM – APR 94004921." The accompanying Investment Appraisal Document is included in the Company's response to OPUC Data Request 60 as "Wallula-McNary IAD Sept 2014."

[1] *In the Matter of PACIFICORP, dba PACIFIC POWER, Petition for Certificate of Public Convenience and Necessity [for the New Wallula to McNary Transmission Line].*
[2] The financial model that Staff refers in this data request is the financial model referred by the OPUC Staff in Exhibit Staff/200, Bless/11, lines 8-13 at http://edocs.puc.state.or.us/efdocs/HTB/um1495htb15551.pdf, where OPUC Staff represented:
"*Q. What financial model and assumptions did Staff employ?*
A. We used the Company's own model, which was provided in spreadsheet form with all formulae and cell references intact as staff requested in DR121. We used the financial assumptions that PacifiCorp used in its anwers to questions 12 and 13 of the Commission's order. PacifiCorp listed those financial assumptions on page 1 of Exhbit PPL/101."

The confidential attachment is designated as confidential under Order No. 14-416 and may only be disclosed to qualified persons as defined in that order.

OPUC Data Request 63

Regarding PacifiCorp's letter dated September 25, 2013[1] in Docket No. UM1495,[2] where PacifiCorp represented that:

> "*At the time the Company applied for a CPCN for the [New Wallula to Mcnary Transmission Line], the Company had executed transmission service agreements with two customers: NextEra Energy Resources, LLC (NextEra) and the Eugene Water and Electric Board (EWEB). On September 18, 2013, NextEra and PacifiCorp executed an Agreement to Facilitate Mutual Termination of Transmission Service Agreement (the Agreement), resulting in an effective date of December 17, 2013, for the termination of the transmission service agreement…*
>
> *Currently, the M2W project is on hold pending a decision by EWEB on whether it will request mutual termination of its transmission service agreement. To date, there has been no material change to PacifiCorp's transmission service agreement with EWEB. However, the Company intends to notify EWEB of NextEra's termination and to engage in discussion with EWEB regarding next steps.*"

Please respond to the following questions:

(a) As of the date of responding this data requests, with how many parties has PacifiCorp executed transmission service agreements; please indicate the name of the parties' and provide copies of the transmission service agreements;

(b) Regarding the Company's response to part (a) of this data request, please provide a general description of each transmission service agreement including information such as transmission capacity requested, type of transmission capacity requested (e.g., network transmission service, point-to-point transmission service, etc.), etc.;

(c) From the time the Company filed its initial filing in Docket No. UM1495 (i.e., August 23, 2010) to the date of responding this data request, has EWEB or other party's requested transmission service changed from "point-to-point" to "network" transmission service or *vice versa*? If "yes," please a explain the Company's response including an explanation of what party (e.g., PacifiCorp, EWEB, other party, etc.) suggested or requested the change; please provide copies of the documentation used to respond this question. If "no," please explain;

(d) Please reconcile the Company's response to parts (a) thorough (c) of this data request with OPUC Staff assertion in Exhibit Staff/200, Bless/8, lines 18-20, that "…[t]he

[1] See at http://edocs.puc.state.or.us/efdocs/HAD/um1495had83324.pdf
[2] *In the Matter of PACIFICORP, dba PACIFIC POWER, Petition for Certificate of Public Convenience and Necessity [for the New Wallula to McNary Transmission Line].*

Eugene Water and Electric Board (EWEB) expressed a clear need for the project. EWEB has contracted for 25 MW of firm **point-to-point [emphasis added]** service".

Response to OPUC Data Request 63

(a) Please refer to the Company's response to OPUC Data Request 52 and the corresponding documents.

(b) Please refer to the Company's response to subpart (a) above.

(c) No. The initial request was for firm point-to-point (PTP) transmission service and has not changed. There are no provisions in the Open Access Transmission Tariff (OATT) to allow a customer to change a PTP request to a network request.

(d) Eugene Water and Electric Board (EWEB) has requested and been granted firm PTP transmission service commensurate with completion of the new proposed Wallula to McNary 230 kilovolt (kV) transmission line.

OPUC Data Request 52

Regarding the following table provided in page 57 of Volume I of PacifiCorp 2015 IRP:

Segment & Name	Description	Approximate Mileage	Status[31] and Scheduled In-Service
(A) Wallula-McNary	230 kV, single circuit	30 mi	• Status: local permitting completed • Scheduled in-service: $\boxed{\text{2017 sponsor driven*}}$
(B) Populus-Terminal	345 kV, double circuit	135 mi	• Status: completed • Placed in-service November 2010
(C) Mona-Oquirrh	500 kV single circuit 345 kV double circuit	100 mi	• Status: completed • Placed in-service: May 2013

Please:

(a) Define the term "sponsor driven" and provide a detailed explanation of what the Company meant with the term "sponsor driven" in the context of the New Wallula to McNary Transmission Line;

(b) Provide a list of the active[1] "sponsors" of the New Wallula to McNary Transmission Line as of the end of each year since the project was conceived[2] until the date of responding to this data request including the following information for <u>each</u> sponsor:

i. The amount of capacity needed from such sponsor;

ii. The type of sponsor (e.g., sponsor to receive network transmission service, sponsor to receive point-to-point transmission service, etc.); please include copies of supporting documentation demonstrating a party's condition of being an sponsor (e.g., memorandum of understandings, etc.)

(c) Has any of the sponsor as part of the Company response to part (b) of this data request changed its request to receive transmission service from "point-to-point" to a "network" transmission service or *vice versa*? If "yes," please:

i. Provide the date in which such change of request transpired;

ii. Indicate the name of the sponsor including a description of the change in the type of transmission service; and

iii. Explain the Company's role in such change of type of transmission service.

Response to OPUC Data Request 52

[1] By "active," Staff means that some sponsors still have the condition of sponsor, but other may have changed its condition to not being sponsor because they do not need transmission capacity anymore.
[2] Staff is requesting this information for each year since the project was conceived to find whether some sponsors may have withdrew its interest of being sponsors at some point in time since the project was conceived.

(a) The term “sponsor driven” refers to a project driven by customer need for which the customer has signed a transmission service agreement.

(b) Since initiation of the project there have been two transmission service contracts entered into by two different customers that require the completion of the proposed line; NextEra and Eugene Water and Electric Board (EWEB) entered into the transmission service agreements in 2009, NextEra agreed to mutual termination of their agreement in 2013.

  i. One transmission service agreement was for 100 megawatts (MW) (terminated) and another is for 25 MW.

  ii. Both customers entered into point-to-point (PTP) transmission service agreements. Please refer to Confidential Attachment OPUC 52.

(c) Yes.

  i. November 13, 2013.

  ii. NextEra. The PTP transmission service request was terminated by mutual agreement between the transmission customer and the transmission provider.

  iii. Per PacifiCorp’s Open Access Transmission Tariff (OATT) Attachment A, Section 3.2 a transmission service agreement can only be terminated by mutual consent of both parties. PacifiCorp’s role was that of the transmission provider acting under the rules of the tariff.

The confidential attachment is designated as confidential under Order No. 14-416 and may only be disclosed to qualified persons as defined in that order.

Attachment C

Table V3.2 – Wyodak Compliance Scenarios

Base Compliance Alternatives					
Case Identifier	Wyodak	Dave Johnston 1	Dave Johnston 2	Dave Johnston 3	Dave Johnston 4
SCR	SCR (3/4/2019)	Retire (12/31/2027)	Retire (12/31/2027)	Retire (12/31/2027)	Retire (12/31/2027)
Early Retirement	Retire (3/4/2019)	Retire (12/31/2027)	Retire (12/31/2027)	Retire (12/31/2027)	Retire (12/31/2027)
Gas Conversion	Conv. (6/1/2019)	Retire (12/31/2027)	Retire (12/31/2027)	Retire (12/31/2027)	Retire (12/31/2027)
Inter-temporal (IT) Compliance Alternatives					
Case Identifier	Wyodak	Dave Johnston 1	Dave Johnston 2	Dave Johnston 3	Dave Johnston 4
IT-1	SNCR (3/4/2019) Retire (12/31/2030)	Retire (12/31/2027)	Retire (12/31/2027)	Retire (12/31/2027)	Retire (12/31/2027)
IT-2	Conv. (6/1/2022)	Retire (12/31/2027)	Retire (12/31/2027)	Retire (12/31/2027)	Retire (12/31/2027)
IT-3	Retire (12/31/2027)	Retire (12/31/2027)	Retire (12/31/2027)	Retire (12/31/2027)	Retire (12/31/2027)
Fleet Trade-off (FT) Compliance Alternatives					
Case Identifier	Wyodak	Dave Johnston 1	Dave Johnston 2	Dave Johnston 3	Dave Johnston 4
FT-1	No SCR	Retire (12/31/2027)	Retire (12/31/2027)	Retire (12/31/2027)	Retire (12/31/2027)
FT-2	No SCR	Conv. (6/1/2022) Retire (12/31/2027)	Conv. (6/1/2022) Retire (12/31/2027)	Retire (12/31/2027)	Retire (12/31/2027)

CERTIFICATE OF SERVICE

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I certify that I have, this day, served the foregoing document upon all parties of record in this proceeding by delivering a copy in person or by mailing a copy properly addressed with first class postage prepaid, or by electronic mail pursuant to OAR 860-001-0180, to the following parties or attorneys of parties.

Dated this 27th day of August, 2015 at Salem, Oregon

Kay Barnes

Kay Barnes
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