BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

Docket No. LC 67

In the Matter of PACIFICORP, dba PACIFIC POWER, 2017 Integrated Resource Plan	Staff's Initial Comments

EXECUTIVE SUMMARY

Staff of the Public Utility Commission of Oregon files these Initial Comments on Pacific Power's (or Company) 2017 Integrated Resource Plan (IRP or Plan), filed on April 4, 2017. Staff will continue to evaluate the Company's plan, conduct discovery and review stakeholders' comments prior to submitting its Final Comments, currently scheduled to be filed on September 1, 2017.

The series of public input meetings which initiated the IRP process began in June of 2016. This process included five state meetings and seven general meetings[1] between June of 2016 and March of 2017. A full list of these meetings as well as a list of the meeting participants can be found in Chapter 2 (pages 21 – 24) and in Appendix C (pages 57 – 62 of Volume II) of the Company's 2017 IRP.

Staff utilizes this first round of Comments as an opportunity to both commend Pacific Power for its comprehensive and detailed IRP, and to raise initial areas of interest that will need additional analysis and potentially additional clarification from the Company.

Staff first offers comments on the major Action Plan items proposed by Pacific Power. Near term actions in Pacific Power's 2017 Action Plan (found in Chapter 9 on pages 265–269 of the Plan) are of paramount importance and continue to be analyzed by Staff. Following the comments on the Action Plan are discussions on various subjects that Staff believes need further clarification from the Company, or that raise concerns with the Company's assumptions or methods used in analyzing this IRP.

Foundational Issues
The Commission expects the IRP process to be transparent and to allow for stakeholder input to the Company's preferred portfolio choice, as well as all the analysis the Company performs to reach this choice. In this IRP cycle, the Company essentially completed the public input process of seven public meetings, beginning in June 2016 and going through the end of the year.The Company then produced a draft Action Plan reflecting no new resource acquisition, as the Company's analysis projected no need for additional resources in order to serve load reliably.

It was only at the end of this process that the Company drastically altered its Action Plan to include both the repowering of 905 MW of existing Company-owned wind resources (Wind Repowering) and the purchase of 1,100 MW of new wind with the associated new transmission line (New Wind) that would enable transport of the New Wind power. These proposed capital investments are projected to cost approximately $3.5 billion. Despite the significance of these costs and unfamiliarity with the projects themselves in the context of the IRP, stakeholders had little to no time to review because it was brought to the table at the very end of the process.

Staff is uncertain as to why the Company waited so long to introduce such major resource acquisitions, but in any case, Staff is concerned that the lack of stakeholder review violates a core IRP principle that fosters an open and participatory process and thus may pose a risk to ratepayers. The late inclusion of such a significant set of investments has deprived Staff and other stakeholders of the opportunity to preview that capital addition proposal and ask the Company questions prior to the filing of the IRP. Staff is further concerned with the late addition of these two Action Items (New Wind and Wind Repower) because the Company has no need to justify these resource acquisitions and makes no claim to have a need – it presents this $3.5 billion acquisition purely as a long-term economic benefit to customers over the course of twenty years.

The fact that the Company has identified no need for the new resources, but instead presents their acquisition as a purely economic decision, means that the normal standards of IRP review may not be relevant because system "need" is an essential element of that review standard. The originating order

[1] "State meeting" topics were concentrated on the impacts of the IRP to individual states; "General meeting" topics concerned the issues of the system as a whole.

that established least cost planning for Oregon regulated utilities, Order No. 89-507, clearly defines the purpose of the planning process – to choose the least-cost approach to meeting the utility's load through thorough consideration of all potential resources. When the utility presents an IRP that establishes the fact that the Company can reliably meet projected load with available resources, it also makes clear that there is no need for further resource analysis or acquisition to fulfill the least-cost planning goals.

This raises another general concern with the inclusion of a major resource in the Action Plan without any apparent physical or compliance need for approximately a decade.. This IRP assumes the investment of more than $2 billion in traditional utility-scale generation 10 years prior to the physical need for that resource at a time when the industry is going through significant structural change. Evolutionary and revolutionary shifts in technology, environmental policies, and customer expectations are changing how investments are made on the electricity system. A commitment of such significant capital carries with it inherent risk of cost overrun and other potential bad outcomes, and the Commission must ask whether the potential benefits to ratepayers are worth exposing them to great risk when there is no reliability need motivating the transaction.

To complicate matters, the Company has begun engaging its state regulators in a conversation to rethink the development of future generating resources and the allocation of costs in the Multi-State Process (MSP) forum. Early concepts indicate the possibility of a very different paradigm for how customers in each Pacific Power state will be served and how new generating resources will be selected and included in rates. These concepts assume this major change in how system resources are developed within the next decade. All of these concerns factor significantly into Staff's review of this filing.

ISSUE DISCUSSION

ACTION PLAN

ENERGY GATEWAY SUB-SEGMENT D2 AND NEW WIND PROJECT

The Company has presented a "package" proposal that includes 140 miles of new transmission, as well as the construction of 1,100 MW of new wind in Wyoming. The Company expects the $2.5 billion project to yield minor economic benefits for customers (in the $20 million range), but only under a limited range of economic conditions. Specifically, the Company acknowledges that the project would likely not be economic if natural gas prices stay low through 2036.

The purpose of the IRP process is to facilitate "least-cost, least-risk" planning with a primary purpose of assuring the Company has adequate resources to provide reliable service to meet anticipated load. Because of the uncertainties inherent in physical, engineered, and economic systems, the least-cost, least-risk planning process requires considerable modeling of factors introducing these uncertainties. It is critical for model assumptions and scope to be non-arbitrary and justified by available data, as well as be considered with a well-reasoned perspective on externalities which can influence past and future trends in these areas. It is not always the case that the least-cost approach to planning will also yield a least-risk solution. Often, there is a necessary tradeoff between cost and risk, and the challenge is to find a portfolio which balances these two criteria. In this IRP, Staff finds the analysis challenging for three reasons.

First, without a clearly defined need for this resource, it is difficult to consider the Action Plan to be least risk. The proposed Action Plan is claimed by the Company to be the least-cost planning approach for resource acquisition based on its stochastic present value revenue requirement (PVRR) portfolio analysis. At the same time, however, the Company claims that it has no deficiency in meeting the projected future load with current resources through the IRP planning window. In addition, the Company does not appear to need the proposed wind resource or transmission resource to meet either federal or state regulatory requirements.

The proposed wind and transmission projects carry the same extensive risks (cost overruns, schedule delays, etc.) as any other capital-intensive projects, despite not being needed to serve load or fulfill a regulatory requirement within the Action Plan timeframe. It would therefore be implausible to consider these projects as less risky than the option of acquiring no resources. It appears instead that the Company considers these projects feasible only because they represent a marginal economic benefit to customers under the analysis.

Second, Staff is interested in knowing the extent to which the economics of this project rely on the existence of the Clean Power Plan or similar, as it appears increasingly likely that there will be no such federal regulation for the next four or perhaps even eight years. Staff expands on this point within the Environmental Regulation Compliance section below.

Third, as mentioned previously in these comments, Staff is concerned that stakeholders have had little to no time to review this proposed capital investment of around $2.5 billion because it was brought to the table at the very end of the process.

Staff continues to investigate the assumptions and methodology the Company has used to draw its conclusion that the acquisition of this wind project and associated transmission will be a net benefit to customers. Staff notes that the Company's analysis shows only a relatively small net benefit – on the order of $20 million savings on a PVRR of nearly $23 billion over 20 years[2] – while incurring risk of potential costs that reasonably could be an order of magnitude greater than the small projected benefit.

WIND REPOWERING

Staff is encouraged to learn that Pacific Power undertook an analysis to determine whether repowering its wind generation fleet could be economic for its customers. The Company's analysis indicates that, despite replacing equipment that has a decade or more of book life remaining, the project is expected to reduce revenue requirement by $35 million over the period 2017-2036, and by $350 million over the period 2017-2049.

Although the Company's analysis indicates a small to material economic benefit to customers over all of the several sensitivity scenarios considered, Staff is still concerned that minor changes in assumptions could result in significantly different results. Staff additionally retains the same concerns with this acquisition as it does with the New Wind/Transmission project discussed previously in these comments. The Company does not support this acquisition with a claim of any need – the resource is not strictly needed for reliability or serving load, nor is the repower needed for RPS compliance within the Action Plan time frame.

The Company has justified this acquisition solely on its economic merits. In light of this, Staff anticipates focusing its discovery on the various assumptions and analysis that provide the support for this proposed economic transaction.

RENEWABLE PORTFOLIO STANDARD (RPS) COMPLIANCE

As outlined in the IRP, Pacific Power's supply-side plan will allow the Company to comply with Oregon's RPS through 2034, with a limited number of unbundled purchases starting in 2018.[3] As Staff currently understands the supply-side plan, the Company is justifying the Wind Repower and the 1,100 MW of New Wind and transmission on a strictly economic basis, and are neither required nor justified by an

[2] Pacific Power 2017 IRP Volume I, Figure 8.52, p. 224.

[3] Pacific Power 2017 Integrated Resource Plan, Volume 1 P.8.

immediate RPS compliance need. Staff plans to confirm that Pacific Power has also assigned no value to the RECs produced by the proposed new projects in terms of valuing the portfolios.[4]

In Order No. 17-010 the Commission approved Pacific Power's revised 2017-2021 Renewable Portfolio Standard Implementation Plan (RPIP). Pacific Power observed as part of that plan that "competitively priced near-term procurement opportunities that can defer the need for future renewable resources until the 2028-2030 timeframe are most likely to yield customer benefits."[5] In that filing, Pacific Power also noted that unbundled RECs can have a significant, low cost role in complying with the RPS in a given year. In the IRP, Pacific Power's supply-side resources meet Oregon RPS compliance needs through 2034. Pacific Power notes in the IRP that it will utilize unbundled RECs for compliance, apply RECs to jurisdictions where they can used when produced in jurisdictions where they are not needed, and sell RECs when REC banks reach certain thresholds.

In recommending approval of Pacific Power's 2016 RPIP, Staff noted mismatches in timing between the RPIP development and approval process and the acquisition of electric Company renewable energy assets.[6] The approved RPIP proposed meeting the five-year needs through existing resources, coupled with unbundled REC purchases.

Staff does not expect the Company to deviate from its approved 2016 RPIP for the five year period of the 2017-2021 RPIP. In order to capture PTC values at the 100 percent level, Pacific Power plans to complete the installation of the new supply-side resources identified in the Action Plan by December 31st, 2020. Accordingly, this resource, which was not included as part of the 2016 RPIP analysis, may be producing additional RECs during the five years of the 2017-2021 RPIP--principally in 2021. However, because Pacific Power utilizes a first-in-first-out REC retirement structure, RECs from the renewable supply-side facilities proposed in this IRP will likely not be used for compliance with the RPS during the term of the 2016 RPIP.

Staff notes however that the 2016 RPIP, which was filed on July 15, 2016 and approved on January 13, 2017, was developed and adopted in a period just prior to the April 4, 2017, filing of the IRP. This timing mismatch highlights the challenges noted by Staff in the recommendation to approve the 2016 RPIP of RPS compliance planning and resource acquisition.

Although the Company is not planning on counting the RECs of the new proposed wind projects toward its near term RPS compliance, Staff anticipates that in the future the benefits of the RECs and the capital cost of the projects will both affect the RPS incremental cost calculation. Staff anticipates further discovery to understand the impact of the proposed supply-side actions on future incremental cost calculations made for the purposes of RPS compliance.

FRONT OFFICE TRANSACTIONS (FOTS) AND MARKET DEPTH

The Company continues to plan to meet energy shortfalls by relying on access to the liquid energy markets (Four Corners, Mid-Columbia, etc.). Staff agrees with the Company that there is likely not a significant capacity deficit looming in 2021, and load can be reliably met with a combination of existing fleet resources and FOTs. Staff believes this is not only the less-costly strategy, but, given the increasing uncertainty about how energy markets will evolve in the future, is also the less risky strategy. Therefore this component of Pacific Power's Plan seems to represent one "least-cost, least-risk" component of its

[4] Pacific Power April 18, 2017 presentation to Staff on IRP components.
[5] Pacific Power's Revised 2017 – 2021 RIPP, Confidential Appendix A, at page 20, Docket No. UM 1790, July 15, 2016.
[6] Order No. 17-010, Appendix A, p.16.

planning at this time. Staff expects the Company to notify the Commission in the event that the Company anticipates or experiences market changes which would alter its Action Plan.

Staff is exploring the differences in expected market depth reported by various regional sources, including the Northwest Power & Conservation Council and the Oregon regulated utilities. Staff will continue to evaluate the reasonableness of Pacific Power's assumptions and conclusions regarding the available level of front office transactions.

ENERGY EFFICIENCY (EE, ORCLASS 2DEMAND SIDE MANAGEMENT (DSM))

Pacific Power proposes to acquire at least 120 MW of EE annually throughout the Action Plan timeframe.

Staff finds Pacific Power's overall position on Class 2 demand-side management (energy efficiency) in the 2017 IRP acceptable, but has several questions that it would like to have addressed prior to final acknowledgement. Staff notes that while incremental forecasted energy efficiency (EE) covers an increasing percentage of forecasted load growth, the total amount of energy savings expected to be achieved has actually dropped relative to the 2015 IRP preferred portfolio. This is due to several factors.[7] Staff is unclear as to what amount of this reduction is forecast for Oregon specifically. Staff plans to work with Pacific Power on this and to determine the extent to which and exact reasons why previously cost-effective energy efficiency may not be pursued in Oregon as part of this IRP. Additionally, Staff would like to better understand the avoided cost methodology used to determine the value and selection of energy efficiency in the Oregon portfolio and how it relates to the new avoided costs values proposed to Energy Trust by Pacific Power for use in 2018.

In addition, Staff is unclear as to what the Oregon-specific EE winter and summer peak reduction is. While Pacific Power did a good job of attempting to comply with Order 14-252,[8] Staff would like to better understand the Oregon contribution to meeting its winter and summer peaks and how Pacific Power made these determinations.

Staff is also concerned about the energy efficiency forecasts for Oregon. In the past, Energy Trust has over-achieved its Pacific Power energy efficiency IRP targets. Staff is unclear how past over-achievements are reflected in current load forecasts and how, if at all, Energy Trust's latest energy efficiency forecasts are adjusted by Pacific Power to reflect Energy Trust's past performance.

THE COMPANY TRANSMISSION PLANNING

Staff does not have any initial concerns with the Company's transmission planning activities, other than the Aeolis-Bridger line proposal as articulated above.

COAL RESOURCE ACTIONS

Staff appreciates the Company's efforts in limiting the cost and risk to customers through its challenges to the Regional Haze plans it is affected by. Analysis presented by the Company in both previous IRPs[9] and

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[7] "Decreased selection of energy efficiency resources relative to the 2015 IRP is driven by reduced loads and reduced costs for wholesale market power purchases and renewable resource alternatives." the Company 2017 IRP (LC 67), April 4, 2017, p.4

[8] As modified by Order 14-288. Order 14-242 states, in relevant part: "In future IRPs, PacifiCorp will provide yearly Class 1 and Class 2 DSM acquisition targets in both GWh and MW for each year in the planning period, by state." See *In the Matter of PacifiCorp*, *dba Pacific Power*, OPUC Docket No. LC 57, Order No. 14-242 (July 08, 2014).

[9] *See* PacifiCorp 2015 IRP, chapter 9.

the current IRP consistently indicates that avoidance of selective catalytic reduction (SCR) is a least-cost, least-risk approach to managing the coal fleet.

The Action Plan lists eight coal plants and their associated federal or state Regional Haze implementation program schedules. The schedules for Hunter 1 & 2, Huntington 1 & 2 and Jim Bridger 1 &2 require the installation of SCRs by 2022. The Company states that its intention is to avoid an SCR installation at the Dave Johnston, Naughton, Wyodak, Cholla and Craig plants through litigation, gas conversion (Naughton and perhaps Craig), or plant closure.

Although the Company discusses the EPA schedules for SCR installation, it does not commit to the installation of the SCRs in the Action Plan. Instead, the coal related Action Items promise both ongoing litigation aimed at eliminating the SCR requirements and updated economic analysis in a future IRP or IRP update.

The Company asserts that avoiding installation of this equipment will save customers hundreds of millions of dollars and retain compliance-planning flexibility for the Clean Power Plan or other potential state and environmental policies. By the end of the planning horizon, Pacific Power assumes 3,650 MW of existing coal generation will be retired. Staff supports the Company's efforts to avoid the SCR installations, the installation of which has been shown by the Company to not be the least-cost planning alternative.

NATURAL GAS RESOURCES

Natural gas-fired resources do not appear in the preferred portfolio until 2029 (one year later than in the 2015 IRP). By the end of the planning horizon, natural gas-fired capacity totals 1,313 MW, a reduction of 1,540 MW relative to the 2015 IRP preferred portfolio. Although recognizing the current strengths of natural gas-fired generation in its resource planning, Pacific Power also recognizes the risks inherent in long term planning around natural gas. Both commodity price and policy volatility have proven high in the past for natural gas, and the Company has consequently constrained natural gas in its portfolio to manage those risks. Staff appreciates that the Company will continue to evaluate potential long-term supply alternatives, including that of energy storage. Staff will continue to work with the Company to evaluate the ongoing need and efficacy of natural gas resources, especially in light of the coming availability of storage and new potential technologies across the planning horizon.

GENERAL ISSUES

ENVIRONMENTAL REGULATION COMPLIANCE

Staff applauds Pacific Power's extensive efforts to model Clean Power Plan (CPP) compliance in conjunction with other environmental regulatory requirements. Pacific Power also imputed shadow carbon prices within its market modeling. These steps demonstrate a level of environmental modeling not seen before, and an effort that Staff believes is commendable. Pacific Power undertook modeling several different Clean Power Plan compliance scenarios which informed nearly all structural aspects of its IRP portfolios runs, scenario modeling and ultimately portfolio selection.

While Staff recognizes the effort undertaken by Pacific Power to model CPP compliance, Staff does have initial concerns related to the handling of the CPP in this IRP, and will need additional information and time to understand how the modeling of the CPP may have informed modeling runs, portfolio selection and preferred resource acquisition.

Pacific Power's CPP compliance model CPP(b) was used as a structural pillar in its preferred portfolio modeling framework. The CPP(b) model makes several assumptions about compliance that ultimately affect resource acquisition strategy. For example, Pacific Power seems to assume a WECC-wide compliance agreement which includes EPA's New Source Complement option. These two assumptions contemplate a level of coordination between WECC states that at present is not indicated by discussions between the states or in regional forums which had taken place during the high-point of CPP discussions. Pacific Power should be aware of this, as it was present at many of these WECC and sub-regional meetings.

Additionally, Pacific Power assumes the WECC states would opt for a New Source Complement. The New Source Complement, with its increased emissions allowance allocations, will likely affect how Pacific Power's aging coal fleet is treated in modeling runs, particularly regarding operating hours and retirement dates. Additionally, in the outer years the New Source Complement may affect resource acquisition decisions, as any new fossil generation would need to fit within the emissions allowance cap. This may shift the model's preference to non-fossil resources, such as wind resources. Additionally, Staff is concerned that other assumptions and modeling choices regarding CPP compliance may have unduly influenced which portfolio ultimately became the preferred portfolio -- such as the inclusion of a shadow carbon price, the assumption that Pacific Power jurisdictional states would opt for early wind treatment under the CPP and participation in Clean Energy Incentive Program (CEIP) under the Clean Power Plan compliance rules.

Additionally, Staff is concerned that Pacific Power modeled CPP compliance in every portfolio and scenario modeling run, save two. Neither of the two non-CPP modeling runs chose the level of early renewable generation acquisition present in the preferred portfolio, suggesting that modeling based on an assumption that the CPP is altered or eliminated could yield a significantly different preferred portfolio than that chosen in this IRP.

Lastly, although at the time Pacific Power developed their IRP modeling framework the Clean Power Plan was still an applicable rule, it is presently in serious jeopardy of being either invalidated or rescinded. Pacific Power, as party to the present action in the D.C. Court of Appeals against the Clean Power Plan, is well aware of this threat to the Clean Power Plan. Having this knowledge, it does not seem unreasonable for Pacific Power to have either adjusted its modeling or conducted additional modeling that does not have the CPP as a weighty factor.

Staff intends to conduct analysis to determine the extent to which Clean Power Plan compliance informs or drives Pacific Power's resource procurement choices in its preferred portfolio.

LOAD FORECASTING & BALANCE

In completing a review of recent Pacific Power IRPs, Staff identified at least three past issues related to the Company's approach to load forecasting and assumptions to meet that projected load, and questions whether these issues have been resolved in this IRP.

The first question for Staff is whether Pacific Power can reliably meet its winter peak in its West Balancing Authority (BA) given the limited transmission between the two balancing areas (PACE and PACW). The second area of concern for Staff is whether the forecasts reflect decreased loads due to customer-owned solar. A related third concern is whether the forecasts reflect decreased loads due to customers opting for direct access. Each of these issues is discussed below.

Can Pacific Power meet its winter peak in its west Balancing Authority Area (BAA)?

The question was raised by Staff in prior IRPs without a definitive answer being agreed upon between Staff and the Company. Although Pacific Power appears to have ample capacity in its fleet to meet the load requirements of the winter peak, there was a question of whether transmission and perhaps other operational constraints might impair the ability of the Company to move the energy. Much of Company's reserve capacity lies in the East BAA while most of the Oregon load lies in the west BAA. The Company has limited transfer capability between the two BAA's and in the past Staff has questioned whether the transfer capability would be adequate to serve the load on the west side during the winter peak.

On page 75 of the IRP, Pacific Power states, "in response to stakeholder feedback in the previous IRP cycle, this 2017 IRP includes the modeling of the winter coincident peak as an improvement over previous IRPs." Table 5.15 on page 92 confirms the Company's ability to meet its west winter peak obligation plus 13 percent reserves (3,670 MW in 2026) using existing west resources and available front office transactions (4,590 MW in 2026). The transmission constraint does not appear to have impeded the Company's ability to meet the winter peak in the West BAA.

Do the forecasts reflect decreased loads due to customer-owned solar?

As customer-side solar generation increases, the utility experiences a reduction in net load when considered on a monthly or annual basis. It was not clear to Staff from examining prior IRPs exactly how this expanding solar base was incorporated into the Company's load forecast.

Page 85 of the current IRP states, "as in the 2015 IRP, the Navigant [Consulting Inc.] study identifies expected levels of customer-sited private generation, which is applied as a reduction to Pacific Power's forecasted load for IRP modeling purposes." Generally, Staff recommends against these types of ad-hoc adjustments to the load forecast outside of the regression model, but in this case, the Company's approach can be viewed as a conservative approach to prevent over-forecasting load. Staff is currently investigating how the Company incorporates customer-sited private generation into its peak load forecasts.

Do the forecasts reflect decreased loads due to customers opting for direct access?

The final order in LC 57(Pacific Power's 2013 IRP docket) states, "Staff and ICNU contend that Pacific Power's assumption of zero long-term direct access loads is not reasonable."[10] Staff maintains that position and believes that the Company's assumption that no additional customers will opt for long-term direct access in the next 10 years is unlikely to match reality. The Company is aware that large industrial customers maximize their economic position; for example, by stating on page 15 of Appendix A, "the Company has seen several large industrial customers cancel expected load when [commodity] prices have fallen." Given that customers will cancel new projects when expected revenues get too low, it is reasonable to assume that customers will switch to direct access if they can save money by doing so.

Staff encourages the Company to develop a forecast of expected load that will opt out of cost of service tariffs and reduce the cost-of-service load appropriately.

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[10] Order No. 14-252, p21.

General Comments on the Load Forecast Methodology

The Company finds a positive relationship between employment and the quantity of retail electricity sales. Accordingly the Company uses employment as a forecast driver in its regression-based forecast of Oregon commercial use-per-day and industrial use-per-day. On page 4 of Appendix A, related to employment, the Company identifies that "the relationship between the economic variable and sales has "flattened", meaning electric usage has become less responsive to the economic variable." This is problematic because the regression equations used by the Company identify a single coefficient relationship between employment and electricity usage. Thus because the coefficient was developed using data related to a relationship that is now more flat, the forecasts may be inaccurate. Staff raised this concern in detail in Staff's comments related to PGE's 2016 IRP and is continuing to investigate whether it impacts Pacific Power's forecasts.

Staff continues discovery into issues related to load forecasting. Staff will investigate the Company's energy and peak forecasts in greater detail and will have further discussion on this subject in the Final Comments.

LOAD AND RESOURCE BALANCE

Overall, Staff finds the Company's Load and Resource Balance analysis to be comprehensive and thorough. Using an annual load growth rate of 0.85 percent, as well as assumptions about generation additions and retirements, energy efficiency savings, hydro contract renewals, and the availability of front-office transactions (FOTs), the Company concludes it will not have any energy shortfall during off-peak hours until 2026, and only very small projected short-duration on-peak energy shortfall in 2022.

On pages 10-11 in the current IRP the Company presents a ten year capacity position which shows effective reserve margins of over 17 percent in the summer and 36 percent in the winter, indicating that the Company has ample capacity to meet projected load in the IRP timeframe and requires no new major resources to do so.

RISK METRICS

Staff has concerns about the use of the upper tail statistics for measuring risk, as well as with the "risk adjusted PVRR" metric, as both analyses may suffer from an element of arbitrariness and lead to inconsistent results for "least-cost, least-risk" planning.

The Company states in its IRP draft that the upper-tail mean PVRR is a measure of high-end stochastic risk. It is calculated by first identifying the Monte Carlo iterations with the three highest production costs on a net present value basis. The portfolio's real-levelized fixed costs (taken from System Optimizer) are added to the production costs, and the mean of the resulting PVRRs is computed. However without removing the expected cost from the upper-tail cost, the metric indicates higher-cost portfolios are generally also more "risky." This is not the case.

The risk-adjusted PVRR is intended to capture risk by incorporating the expected value cost of low-probability, high cost outcomes. It is calculated by the Company as the PVRR of stochastic mean system variables plus 5 percent of system variable costs from the 95th percentile. It is based on 50 Monte Carlo simulations for each resource portfolio. The PVRR of the fixed costs are added to this system variable cost metric. The risk-adjusted PVRR is supposed to represent a consolidated stochastic cost indicator for portfolio rankings. Staff is concerned about potential shortcomings in this screening metric: The Company provides no rationale for the 5 percent risk weighting. It is unclear if this value is chosen based on some statistical or natural clustering measure, or if it is based on economic principles. It is also unclear to Staff how this measurement – if not arbitrary – is a better estimation of risk than the other PVRR metrics employed by the Company.

The variability of portfolio cost around the expected value is certainly a reasonable measure for the severity or intensity of risk. However, variability metrics in themselves do not measure the probability of an event occurring. Staff believes both pieces of information are crucial to more fully understand the amount of risk represented by a portfolio.

RECENT RESOURCE PROCUREMENT ACTIVITIES

Pacific Power notes that it has conducted the following four requests for proposals (RFPs) since November 2015:

- 2017 Transfer Frequency Response RFP
- 2016 Natural Gas Asset Management and Supply RFP
- 2016 Renewable RFP
- 2015 Market Resource RFP[11]

Staff did not have any specific issues or obvious reason for concern regarding these RFPs. However given the amount of money potentially involved and the impact current procurement activity could have on future planning, Staff requested an opportunity to review all materials related to these RFPs. The Company was agreeable and facilitated a review of these materials. Staff was able to confirm that in all cases, the modeling and analysis was appropriate and at the right level of sophistication for the task at hand. Staff does not anticipate any further need for review of these RFPs in this IRP process.

MODELING AND STOCHASTIC PARAMETERS

The 2017 IRP modeling and evaluation approach consists of three screening stages used to select a preferred portfolio, including Regional Haze screening, eligible portfolio screening, and final screening. Pacific Power uses the System Optimizer (SO) capacity expansion module to produce unique resource portfolios across a range of different planning assumptions. Informed by the public input process, Pacific Power ultimately produced and evaluated 43 different SO portfolios for its 2017 IRP. Pacific Power uses Planning and Risk (PaR) modeling to perform stochastic risk analysis of the portfolios produced by SO. For each SO portfolio, PaR studies are developed for three natural gas price scenarios (low, base, and high) and two carbon dioxide (CO2) emissions limit assumptions, which together form six price-emissions scenarios. The resulting cost and risk metrics are then used to compare portfolio alternatives and inform selection of the preferred portfolio. Taking into consideration stakeholder comments received during the public input process, Pacific Power also developed 24 sensitivity cases designed to highlight the impact of specific planning assumptions on future resource selections along with the associated impact on system costs and stochastic risks. Six of the sensitivities developed over the course of the 2017 IRP were considered for the preferred portfolio.

In order to perform its modeling analysis, the Company made several assumptions related to date conventions, inflation rates, and discount factors.

Staff questions certain specific assumptions. in particular, Staff questions the in-service date assumed. Specifically, in-service dates of January 1 are used, with the exception of coal generation. June 1 is the in-service date used for coal generation. The Company states that the reason for the use of variable in

[11] Pacific Power 2017 Integrated Resource Plan, Volume 1 P.53.

service dates by resource type is due to need for alternatives to be available during the summer peak period. Staff is unclear as to why the Company treats coal-to-natural gas conversions separately for this purpose. Availability of coal versus other resource types noted do not vary seasonally. It is possible that the availability, storage and delivery of natural gas resources to meet peak summer demand are embedded in the Company's assumption, but this is not clearly articulated. Staff continues to explore this issue.

The Company performed complex modeling and portfolio analysis as part of the IRP process. The model and portfolio evaluation appears to be robust and of a level of complexity well suited to the IRP process. Staff is interested in the Monte Carlo analysis Pacific Power applied for the portfolio evaluation. Staff has questions regarding the modeling rules. For instance, it is unclear to Staff why the draws for hydroelectric generation are applied on a weekly basis, whereas others are applied daily. In addition, Staff questions why the expected values of the simulation are the average of all 50 iterations. Depending on whether or not the simulation was a Markov Chain Monte Carlo, the averaging may simply result in a portfolio selection that is identical to the model inputs. Staff continues discovery regarding the detailed Monte Carlo methodology used by the Company to answer these questions.

With regard to the Company's treatment of loss of load probability and cumulative CO2 emissions in the IRP, Staff is interested in how assumptions related to future changes in transmission topology as well as potential shifts in CO2 emissions regulation might be integrated into the model. In general however, the Company appears to be appropriately considering a wide range of variables in its studies. Staff would appreciate the Company providing greater clarity regarding the aforementioned assumptions which will help Staff to evaluate the selection of cases for analysis, and least-risk portfolios.

The Company updated and re-estimated its 2015 stochastic parameters for use in the current Planning and Risk (PaR) model runs. The purpose of the PaR model is to stochastically shock the electricity price forecast (and other key drivers) which will in turn alter the model outputs. By comparing the variability in the output to the variability in the input, the Company could draw conclusions about PVRR sensitivity to the input variables. As an example, if a five percent increase in gas cost assumption results in a 10 percent increase in system cost (i.e., PVRR) one could conclude that the output is relatively sensitive to input price assumptions. If on the other hand the five percent increase in gas cost results in insignificant change in PVRR, one could assume the modeling is relatively insensitive to gas prices.

The Company uses a two-factor mean reverting model.

The general process used by the Company in the development of its stochastic parameters is as follows: Short term uncertainty process parameters are assessed; statistical distributions and time steps for uncertainty quantification are chosen; data sets are selected for the chosen time step; a decision of how to treat missing variables (i.e., disregard versus interpolate) is made; uncertainty is estimated by looking at the daily price deviation for the variables; price expectations are calculated; and uncertainty parameters are computed for each variable by regression analysis.

Short-run stochastic parameters were used in the IRP, and the Company set long run parameters to zero. The basis for the decision to set long run parameters to zero given by the Company is that it cannot re-optimize its capacity expansion plan. Consequently, only the expected yearly price and load growths are simulated for the forecast horizon.

The Company states that the key drivers that affect price determination fall into two categories--loads and fuels. The Company states that targeting only key variables simplifies the analysis while effectively capturing sensitivities of the larger subset of individual variables which fall under the penumbra of the key drivers. Staff has concerns that incorrect selection of input-level variables can propagate uncertainty across the forecast horizon. Staff is also concerned about the variability in the fits of the regression analysis of the uncertainty parameters. Specifically, there does not appear to be consistency in the correlations across the tested parameters, and Staff questions whether there is justification for using both the regression analysis as well as input variables.

Staff will work with the Company to evaluate the data sources used in the stochastic parameter analysis, and to better understand the regional scale modeling. Staff is particularly interested in understanding why missing price data were “blanked” for natural gas prices, but interpolated for electricity. Staff is also interested learning about the significance of the model “fits” for the different scenarios. However, the use of a mean-reverting model, and the use of lognormal distributions and regression analysis appear to be reasonable and generally accepted distributions and analysis tools for stochastic parameter estimation in an IRP process.

PLANNING RESERVE MARGIN STUDY

The planning reserve margin (PRM) is a percentage of coincident system peak load that is needed to ensure that there are adequate resources to meet the forecasted load over time. PRM will provide the Company a “cushion” to account for forecasting errors when matching resources to load. The level of PRM that is considered adequate for reliability is determined by the Company through a PRM study. Setting the PRM too high will result in wasteful cost since capacity is being acquired that will likely never be needed. On the other hand, setting the PRM too low may present a reliability issue at peak times, especially if there is an unexpected loss of a generating resource when it is needed. The PRM study is designed to find the best balance between cost and reliability margin.

In the Company’s PRM study, the relationship between cost and reliability among ten different PRM levels is evaluated to account for variability and uncertainty in load and generation resources. A stochastic loss-of-load (LOL) study is then performed using the Planning and Risk production cost model to calculate reliability metrics for each PRM level.

There are five basic modeling steps described by the Company:

1. The Company’s System Optimizer (SO) model is used to produce resource portfolios among different PRM levels;
2. The Planning and Risk model is used to produce reliability metrics for each resource portfolio;
    a. Each reliability metric is adjusted to account for the Company’s participation in the Northwest Power Program (NWWP) reserve sharing agreement.
3. The Planning and Risk model is used to produce stochastic variable production costs for each resource portfolio;
    a. Monte Carlo random sampling of stochastic variables is used to produce a distribution of system operation.
4. Marginal costs of reliability using the outcomes of different PRM levels are calculated;
    a. A 10 year test period is used for the marginal cost outcomes across different PRM levels.
5. PRM level is selected based on model results.

As the PRM level is increased from 10 percent to 20 percent, additional resources are added to the portfolio. The resources the Company adds are demand side management (DSM),; gas fired combined cycle combustion turbines (CCCT), gas fired coal combustion turbines (SCCT), renewable resources, and front office transactions (FOTs). Staff has initiated requests regarding the rationale for resource selection combinatorics at different PRM levels. It is not immediately clear how System Optimizer resolves the resource selection in varying cases.

Staff also will work with the Company to understand better how the Monte Carlo random sampling was performed; particularly whether any rules were applied to the random sampling – such as whether selected stochastic variables were removed from the sample pool upon selection. Staff is also interested in understanding why a ten year test period is used for the marginal cost outcomes across different PRM levels. Finally, Staff notes that the incremental cost of reliability (as calculated) rises dramatically as PRM levels increase from 16 percent to 20 percent and would like to better understand this steep increase.

At this initial stage, Staff is generally satisfied with the procedures the Company used in the PRM study as well as the selected 13 percent target PRM (pending further clarification of certain modelling assumptions and steps). However Staff will work with the Company to clarify some details about the methodology and assumptions.

FLEXIBLE RESERVE STUDY

The 2017 Flexible Reserve Study (FRS) estimates the regulation reserve required to maintain the Company's system reliability and comply with North American Electric Reliability Corporation (NERC) reliability standards, as well as the incremental cost of this regulation reserve. The Company's overall operating reserve requirements (regulation and contingency) are also compared to its flexible resource supply across the IRP study period. The Company must maintain sufficient regulation reserve to remain within NERC's Balancing Area Authority (BAA) control error limit in compliance with a new standard that became effective on July 1, 2016 (BAL-000-01-2). This standard requires a utility to compensate for changes in load demand and generation output by estimating the amount of regulation reserve required to manage variations in load from variable energy resources (VERs) as well as non-VERs. The Company's study concludes that the regulation reserve burden associated with wind deviations from scheduled amounts are twice the amount associated with solar, three times the amount associated with load, and four times the amount associated with non-VERs. As a result, the Company attributes different levels of regulation reserve to load, wind, solar and non-VERs. Based on the information available to Staff in the IRP, there appears to be justification for the Company to attribute different levels of regulation reserve to these variables.

Because the methodology in the 2017 FRS differs from prior years, Staff has initiated discovery to better understand the data sources and calculations utilized by the Company. In these comments, Staff will primarily address changes from prior years. The first major change from prior years is that the regulation reserve requirements are now tied directly to compliance with the new BAL-001-2 standard. Second, the FRS uses a portfolio-wide approach to determine the overall regulation reserve requirement, including the aggregated diversity benefits for all customer classes. Third, all customer classes that contribute to the overall requirement are now allocated to a share of the diversity benefits resulting from aggregating their requirement with that of the whole system. Finally, the FRS reflects updated data based on actual operational experience, including data and benefits from the Company's participation in the EIM.

Staff has initiated discovery regarding the data sources and calculations used in the FRS. Specifically, Staff is interested in understanding the Company's data correction procedures, and the proportion of data that were excluded from analysis. Staff is also interested in understanding the Company's assertion that BAL-001-2 events are rare. Because the standard is new for these types of events, Staff would like to learn how this conclusion was drawn.

Staff expects that the discovery process will clarify details of the Company's analysis. However, it is expected that the Company is justified in attributing different levels of regulation reserve to load, wind, solar, and non-VERs, based on the data sources, methods, and calculations employed.

DEMAND RESPONSE

Staff has questions about how Pacific Power models and expects to acquire demand response over the next several years. Additionally, Staff is concerned that Pacific Power seems to plan long lead times for demand response development—particularly in Oregon—even though the Company has solid experience in implementing demand response in other areas of its system. Staff found Pacific Power's demand response potential study to be complicated and disjointed. This makes analysis extremely time consuming. At present Staff finds the study to be non-transparent. Additionally, Staff is concerned that Pacific Power may not be undertaking full efforts to pilot and acquire cost effective demand response as identified in the demand response potential study and as required by SB 1547. Staff will take steps to work with the material provided but may want revisions to the narrative and to the study's structure in future IRPs

SMART GRID

The most significant smart grid update in the IRP involved Pacific Power's description of its intention to install Advanced Metering Infrastructure (AMI) technology. As part of the AMI rollout, the Company intends to replace 590,000 existing customer meters with smart meters. Pacific Power plans on initiating installations of the new smart meters this year and finishing the installations by 2019. The Company's decision to go through with the meters is attributed to reduced operations and maintenance costs, a platform for future smart grid applications, increased worker safety, reduced emissions, and increased data for efficient management of the network.

While additional details about the AMI rollout are found in Pacific Power's 2016 Smart Grid Report in docket UM 1667, in the 2017 IRP, the Company does not indicate how the rollout intertwines with the IRP. Pacific Power does not present the costs or savings of this project in its IRP, nor does the Company indicate how or whether the new technology will enable or further support growth of demand response, distributed energy resources, or energy efficiency applications. Instead, the Company states that the "net present value of implementing a comprehensive smart grid system throughout Pacific Power is negative," and does not elaborate on what "comprehensive" entails.

Given that the AMI rollout is a significant addition to the Company's smart grid anatomy, Staff is surprised that few additions to planning and resource applications are included in the current IRP. Staff requests that some commentary about any interrelation (or lack thereof) between AMI and planning and resource applications be included in the Company's Reply Comments, specifically as it pertains to AMI data, demand response, distributed energy resources, and energy efficiency applications.

DISTRIBUTION SYSTEM PLANNING

The Company included distributed energy resources (DERs) including energy efficiency, demand response and privately owned distributed generation within the IRP yet, as noted in the Smart Grid section above, lacked discussion or analysis regarding how the Company's grid modernization investment decisions will impact further growth of DERs and vice versa. It is widely recognized that increased adoption of DERs has the potential to greatly change the power sector such that within the planning horizon of the IRP, the distribution system itself will become a significant resource. Planning for the cost effective, prudent transition to two-way managed power flow has led other state regulators to adopt some form of Distribution System Planning (DSP). Although Oregon and the Company's system have unique characteristics that may lead to the conclusion that DERs are small and of little impact today, beginning to adapt our regulatory planning needs now to enable transparent review of grid modernization investments could be helpful to the Commission and the Company.

As Staff found in reviewing this IRP and PGE's 2016 IRP, there are three main drivers behind Staff's mention of DSP at this time.

1) A comprehensive, transparent look at how the Company is planning for grid modernization that pulls together elements of Smart Grid reports, existing distribution planning and IRP planning is missing. Staff suggests that integrating our planning processes and requirements would better provide the Commission with tools necessary for review of the prudency of grid investment plans.

2) Current planning processes may be underrepresenting the potential impact of DERs. For example, in Appendix O, Navigant estimates growth of distributed generation in Oregon ranging between 200 MW and 550 MW in 20 years based on assumptions for technology costs, system performance and electricity rates. If in five years the Company were able to identify locations within the distribution system where installation of DERs would provide higher value and was able to compensate customers or third parties for the increased value, would installations grow beyond what is forecasted in this IRP?

3) There may be a cost of not adopting a comprehensive process DSP that sufficiently considers market advancements and opportunities for improving the efficiency of grid operations.

Staff plans to continue to explore these issues and provide process recommendations in the Final Comments on the IRP for next steps for investigating, defining, and potentially implementing DSP over the next several years. Staff is interested in hearing the Company's response to the following questions in its reply comments.

- How does the Company envision improving the connection between planning for and investing in a distribution system that is needed to efficiently, reliably and safely manage higher levels of DERs?
- Does the Company see benefit in reassessing and possibly reworking the current regulatory processes connecting locational value dockets (e.g., Resource Value of Solar (UM 1716) and Energy Storage (UM 1751)), distribution infrastructure planning, the Smart Grid Report and the IRP?
- Would greater, more comprehensive regulatory guidance related to distribution system planning enable more efficient prioritization of Company action and resources toward grid modernization goals?
- Could greater transparency of location specific aspects of distribution system resources and load lead to greater adoption of cost effective DERs than currently reflected in IRP planning assumptions and potentially lessen cost of system operations?

PROGRESS ON PREVIOUS ACTION PLAN ITEMS

The Company's progress on past IRP orders is outlined at the end of Chapter 9 – Action Plan and Resource Procurement (pp. 270-275). These items are discussed below.

1) Renewable Portfolio Standard Compliance tasks

The Company is projected to meet the Oregon RPS through 2027 with existing resources, including the REC bank. Therefore, it plans no additional RPS compliance acquisitions, either bundled or unbundled, through the Action Plan timeframe. However, the Company does actively manage its REC bank, which involves the sale of vintage RECs not needed for compliance purposes.

Staff has no issues at present with the Company's REC management.

The Company also notes that it is no longer actively seeking compliance with the Oregon Solar Capacity Standard since this was eliminated with the passage of SB 1547.

2) Front Office Transactions

The Company continues to acquire short-term firm market purchases explicitly for delivery during on-peak periods. For 2017, it had secured approximately 450 MW to 700 MW of purchases for the 2017 peak.

Staff has no issues at present with the Company's purchase of short-term firm products. However, Staff continues to analyze the market depth and potential constraints posed by any illiquidity in the market. No particular issues have been identified to date.

3) Demand Side Management

a) Class 1 DSM (Load Control)

Pacific Power has implemented an Irrigation Load Control pilot program that was approved on May 4, 2016. Staff is encouraged that the Company has implemented a load control pilot and expects to be able to analyze results from the program in the coming months.

b) Class 2 DSM (EE)

The Company continues to meet or exceed Class 2 DSM targets. Staff has no issues at this time with the Company's EE procurement activities.

4) Coal Resource Actions

a) Naughton Conversion

The Company continues to analyze the economic benefit of converting this unit to natural gas, as opposed to shutting the unit down at the end of 2018. Pacific Power is keeping both options open until the next IRP update.

b) Dave Johnston

The Company is currently in litigation, the result of which will determine whether this plant is closed at the end of 2027 without additional emissions control. If it loses on appeal, the 2017 IRP Update will contain additional analysis to determine the best course of action for the plant.

c) Wyodak

The Company is awaiting results of its appeal and will provide further information in the 2017 IRP Update.

d) Cholla

The Arizona implementation plan was accepted by the EPA, which will include closure of this plant in 2025 without SCR installation.

Staff continues to monitor the legal activities surrounding the Company's coal resources, but has no particular issues at this time.

5) Transmission Items

a) Energy Gateway Permitting

Pacific Power continues the permitting activities related to this project.

b) Wallula to McNary line

Pacific Power continues the permitting and right-of-way activities related to this project.

Staff has no issues with these transmission activities at this time.

This concludes Staff's comments.

Dated at Salem, Oregon, this 23rd day of June, 2017.

Geoff Ihle

Geoffrey Ihle
Senior Economist
Energy Resources and Planning Division