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[redacted]
EXHIBIT 22
RMP cross
800-631-6989

Oregon Public Utility Commission
201 High St SE, Suite 100
Salem, Oregon 97301

Re: LC 66 - Initial Comments on behalf of ICNU on the 2016 Integrated Resource Plan of Portland General Electric Company

Dear Commissioners,

I appreciate the opportunity to provide initial comments on behalf of the Industrial Customers of Northwest Utilities ("ICNU") on the 2016 Integrated Resource Plan ("IRP") of Portland General Electric Company ("PGE" or the "Company"). ICNU is a non-profit trade association representing large electric utility customers located throughout the Northwest, including customers of the Company. In addition to these comments, Tyler Pepple of Davison Van Cleve will also be filing comments on behalf of ICNU in this matter.

In summary, I recommend the Commission not acknowledge two Supply-side actions in the Company's 2016 IRP Action Plan:

1) Supply-side action "a. Renewable Resources" and,

2) Supply-side action "b. Capacity Resources."

With respect to Supply-side action "a.", my analysis demonstrates that a Just-in-Time ("JIT") strategy is a more prudent, and less risky, way to plan for renewable portfolio standards ("RPS") compliance. Such a strategy would postpone the need for a physical RPS compliance until 2030, or beyond.

With respect to Supply-side action "b.", the Company has not demonstrated a near-term need to acquire a supply-side capacity resource. My analysis shows the Company is surplus in capacity until the winter of 2021. After accounting for potential market purchases, the 2021 deficit is only approximately 243MW. Rather than issuing an immediate request for proposal ("RFP") for this potential capacity need, I recommend the Company pursue a flexible approach. Specifically, I recommend that the future capacity need be further monitored and studied by the

Company over the next two years, considering changes in loads, availability of market purchases, and other demand-side alternatives. This will provide the Company with greater flexibility in planning for this need, if conditions—such as loads, contract extensions, resource availability, demand response opportunities—change.

I. COMMENTS

In general, ICNU is concerned with the prospect of substantial capacity and renewable resource additions in the IRP action plan. The Company has just completed a series of major capital projects, including the construction of three large utility-owned generating facilities: Port Westward II, Tucannon River Wind, and Carty Generating Station. These three generating facilities collectively consisted of over $1.2 billion in capital and have placed material upward pressure on the Company's rates in recent years. This recent rate pressure, however, would seem small relative to the potential rate increases associated with the proposal in the action plan for 850 MW of thermal capacity and 515 MW of Pacific Northwest wind capacity.

Put simply, the analysis in the 2016 IRP is inadequate to justify such significant resource actions. The significant amount of work and effort undertaken by the Company to prepare the IRP is appreciated. The Company's analysis, however, fails to answer some basic questions—such as the amount of capacity available through front office transactions—and is based on certain methodologies with which ICNU fundamentally disagrees.

My concern with the Company's approach can be categorized into three general areas. First, I disagree with the proposed resource adequacy assessment, based on the black-box, Renewable Energy Capacity Planning Model ("RECAP") model. Second, I disagree with several aspects of the methodology employed to conduct portfolio analysis. Third, I disagree with the methodologies used by the Company to evaluate various RPS compliance strategies. Each of these areas will be discussed in the sections that follow.

II. RESOURCE ADEQUACY

In the 2016 IRP, the Company proposes a new methodology for evaluating resource adequacy, based on the RECAP model. RECAP is an unlicensed, freely available computer program developed by the California-based consulting firm Energy + Environmental Economics ("E3"). Given its black-box nature, ICNU does not necessarily believe it is appropriate to use the RECAP model in Oregon to establish resource adequacy requirements for the Company. Rather, the use of a traditional, Planning Reserve Margin ("PRM") is a more straightforward, proven way for the Company to evaluate resource adequacy. As it has been deployed, the RECAP model would result in an effective increase to the PRM from 12.0% to approximately 19.4%. [1/] Yet, the existing PRM has produced reasonable reliability in the

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1/ See 2016 IRP, Volume II, Appendix P, Table P1. The 19.4% figure was calculated by taking the average of the values on the line TRM% over the period 2017 through 2021.

Company's service territory for many years. Accordingly, the Company's proposal to increase the PRM is inappropriate. Given the peaking capability of the Northwest hydroelectric system and other unique characteristics of the region, the Northwest Power and Conservation Council calculated a winter Adequacy Reserve Margin—a functional equivalent of a regional PRM—of 0.1% in 2026,[2/] a value which is directionally and conceptually inconsistent with the Company's proposal to increase its effective PRMs by 61.6%.

1. The RECAP Model is Not Suited to Model Resource Adequacy in the Northwest

The RECAP is a compilation of python computer programs and excel spreadsheets, which rely on a "[n]eural network model [...] to estimate complex relationships between inputs and outputs using hidden nodes that weigh and transform input data and optimize fit to output data."[3/] The model was developed for use in California and is highly complicated. Due to its black-box nature, the results it produces are also not necessarily transparent or easy to understand. In fact, when benchmarked against the PRM used in the 2013 IRP, it produces materially different results that cannot be reconciled in a straightforward manner.

While the RECAP model was developed in California, it is not actually used by regulators in California for resource adequacy. Resource adequacy requirements for California utilities have historically been based on a deterministic PRM, similar to that which PGE has historically used.[4/] There have been efforts in California to move towards a more probabilistic approach. My understanding, however, is that the modeling tools used to develop those studies are much more comprehensive than the RECAP model, relying more on historical data and less on data extrapolated through use of neural network models.

The RECAP model is not suitable to evaluate resource adequacy for utilities in the Northwest. Unlike many other regions, hydroelectric conditions are the principal driver of reliability in the Northwest. Accordingly, regional hydrology should be a principal consideration in evaluating resource adequacy for any utility located in the Northwest. Yet, the RECAP model only considers a limited time series of historical hydro data and does so only for Company resources.

Markets in the Northwest also are different than in California. With a substantial amount of surplus market capacity available through the Bonneville Power Administration, the Mid-Columbia publics,[5/] British Columbia's Powerex, and approximately 3,000 MW of in-region capability from independent power producers, it is common for utilities in the Northwest to rely more heavily on capacity available through bilateral markets for purposes of resource

2/ Northwest Power and Conservation Council, Seventh Power Plan, at 11-23, Table 11-7 (represents the average of Q4 and Q1) (Feb. 2016).

3/ E3, Renewable Energy Capacity Planning Model, User Manual at 7 (June 17, 2015)

4/ See e.g. CAISO, April 21st Public Workshop, Regional Resource Adequacy Revised Straw Proposal at 26-34. Available at http://www.caiso.com/Documents/Agenda-Presentation_RegionalResourceAdequacy-RevisedStrawProposal.pdf

5/ The Mid-Columbia Publics include: Grant PUD (Wanapum and Priest Rapids), Chelan PUD (Rock Island and Rocky Reach), Douglas PUD (Wells).

adequacy. A critical question in evaluating the Company's resources adequacy is the extent to which the Company should rely on regional markets. The RECAP model, however, does not attempt to determine the depth of markets in the Northwest.

In fact, it is a flaw of the 2016 IRP that it did not analyze the degree to which the Company can rely on market purchases to satisfy load requirements in a reliable manner. Given the depth of the markets in the Northwest, as well as availability of a substantial amount of winter import capability from California, market availability should be a fundamental question addressed by the IRP of any utility in the Northwest prior to building a new resource.

Notwithstanding, the Company assumed little-to-no market capability in the RECAP model, and the market capability that was included was modeled in a way that is inconsistent with how the RECAP model is designed. The RECAP model contains special inputs to model market imports. The Company, however, did not use those designated inputs for market imports in its RECAP analysis. The Company set the market import capability in RECAP to zero, and instead modeled market purchases as if they were a variable energy resource, based on a historical profile of market purchases. Based on the way that the RECAP model generates stochastics, treating historical market purchases the same way as an intermittent resource does not accurately reflect the actual capability the Company derives from the market, and accordingly, is a flawed methodology.

In contrast to the methodology used by the Company, my opinion is that it is more appropriate to consider regional resource adequacy when evaluating the amount of available market capacity. The Northwest Power and Conservation Council (the "Council") recently published the Seventh Power Plan. In that document the Council found that "[i]n more than 90 percent of future conditions, cost-effective efficiency met *all* electricity load growth through 2030 and in more than half of the futures *all* load growth for the next 20 years."[6/] While the Council's recommendation was based on an ambitious forecast for demand response additions, the Council's report suggests that there will be sufficient regional capacity, an indication that surplus capacity in the region will likely be available through bilateral markets.

Due to these deficiencies, I recommend that the Commission not accept the RECAP model for evaluating the resource adequacy requirements of the Company. On its face, the RECAP model produces results that are unreasonable relative to the Company's past planning practices and fails to adequately consider unique aspects of the power supply system in the Northwest.

2. A Traditional Approach Based on a Planning Reserve Margin Should be Used to Consider Resource Adequacy Requirements

Rather, I recommend that the Commission evaluate the resource adequacy requirements of the Company using a traditional approach, relying upon a deterministic PRM. This sort of

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6/ Northwest Power and Conservation Council, Seventh Power Plan at 1-1 (emphasis in original).

approach is a simpler way to gain an understanding of the Company's resource needs and to evaluate resource alternatives to satisfy those needs.

Appendix P of the 2016 IRP contains a high-level load and resource balance. However, I have identified several problems with the load and resource balance presented in Appendix P, many of which will be discussed below.

As a result of these problems, I developed an independent load and resource balance, in an attempt to better understand the resource needs of the Company in the coming years. My analysis is more detailed than that presented by the Company in Appendix P and provides a more realistic assessment of the Company's capacity position following the retirement of Boardman. My analysis has been provided in Confidential Attachment A and is summarized in Table 1, below.

TABLE 1
Preliminary Load and Resource Balance (MW, Winter Peak)
No Resource Additions

	2018	2019	2020	2021	2022	2023	2024	2025	2030	2035	2040
Resources											
Coal	809	809	809	296	296	296	296	296	296	-	-
Natural Gas	1,851	1,851	1,851	1,851	1,851	1,851	1,851	1,851	1,851	1,851	1,851
Hydroelectric	804	804	804	804	804	804	804	584	574	574	574
Renewable Resources	84	84	84	84	84	84	84	84	81	81	72
Qualifying Facilities	82	82	82	82	82	82	82	82	82	81	81
Seasonal Contracts	100	100	-	-	-	-	-	-	-	-	-
Total Existing Rsrcs	3,730	3,730	3,630	3,117	3,117	3,117	3,117	2,897	2,885	2,587	2,578
Net Load + PRM	3,633	3,645	3,611	3,660	3,671	3,686	3,705	3,729	3,904	4,108	4,343
Net Position (Before FOT)	97	85	18	(543)	(554)	(569)	(588)	(831)	(1,019)	(1,520)	(1,765)
Available Front Office Transactions*	300	300	300	300	300	300	300	300	300	300	300
Net Position (After FOT)	397	385	318	(243)	(254)	(269)	(288)	(531)	(719)	(1,220)	(1,465)

* Preliminary assumption to be updated in Final Comments

As can be seen from Table 1, the Company is faced with little, to no, near-term peak load growth, after accounting for incremental demand-side management and distributed generation resources. The above analysis also shows that, after the retirement of Boardman beginning in 2021, the Company is faced with a capacity need of approximately 243 MW. This need is substantially less than the 850 MW capacity resource addition proposed by the Company. Some of the differences between my load and resource analysis and the Company's are detailed as follows.

Planning Reserve Margin

As noted, the Company's analysis assumed an approximate 19.4% PRM. While I believe that a 12% PRM used in the 2013 IRP is too high—particularly given the fact that the

Council has determined that regional adequacy margins are closer to zero—for purposes of this proceeding, I used a 12% PRM to evaluate the Company's expected resource needs in Confidential Attachment A. That PRM is reflected in the Net Load values detailed above. Demand side resources are also reflected as an offset to Net Load in the above table, in contrast to the tables detailed in Appendix P, which separately detail demand-side resources in a manner similar to supply-side resources.

Front Office Transactions

In Appendix P, the Company assumed that only 98 MW of market transactions would be available in 2021 to meet peak loads. This assumption is largely unsupported in the 2016 IRP, and based on my experience, is arbitrarily low.

For purposes of the initial analysis summarized in Table 1, I assumed that the Company had the ability to import approximately 300 MW of winter peaking capacity from the Mid-Columbia and California-Oregon Border ("COB") markets. This is a preliminary assumption and may still be unrealistically low, given the Company's transmission access to regional markets. Accordingly, the Company should provide further information regarding available market capacity in its Reply Comments.

In its Reply Comments, I particularly request that the Company consider that it has a substantial amount of import capability from the COB market. In response to ICNU Data Request 17, for example, the Company indicated that it has rights to approximately 727 MW of transmission from COB. Customers are paying for transmission from COB, and thus, should be reaping the reliability benefits associated with access to that market. Because California is summer peaking, the Company should able to realize a significant amount of capacity from this transmission link. Just as PacifiCorp includes import capability from COB in its IRP, the Company should also consider COB imports in its IRP.

Load Forecast

Both the load and resource balance and RECAP analysis prepared by the Company appear to have been based on an outdated load forecast. In the Company's final MONET update in Docket No. UE 308, for example, 2017 peak loads were approximately 97.5 MW lower than reflected in Appendix P to the 2016 IRP. Similarly, loads in the RECAP model were overstated by an even greater amount, approximately 187.7 MW, compared to the load forecast provided in MONET in Docket No. UE 308. The difference between the peak load forecast in RECAP and the peak load forecast in the Company's load and resource balance may offer one explanation for the excessively high planning reserve margin assumed in the Company's analysis.

Based on the final MONET update, my analysis makes a 97.5 MW downward adjustment to peak loads in Attachment A.

These variances in the Company's load forecast are particularly concerning given a recent report by the Berkeley National Laboratory that demonstrated that many utilities, including the Company, have systematically overstated load growth rates in historical IRPs. A copy of that report, titled "Load Forecasting in Electric Utility Integrated Resource Planning" can be accessed as of January 2017 through the following hyperlink: https://emp.lbl.gov/sites/all/files/lbnl-1006395_0.pdf.

Load forecasts are one of the more important aspects to consider when evaluating resource adequacy, and thus, should be updated based on the best information available to the Company. It certainly would not be prudent for the Company to follow through with its plan to acquire a major resource, based on an outdated load forecast. This is one of the reasons I believe it is appropriate for the Company to continue to monitor its load forecast and resource needs for a few more years, prior to taking any concrete resource actions for 2021.

Hydro Capability

In forming its peak load and resource balance, the Company has understated the capacity available from its hydro electric facilities. It appears that the Company has used average annual energy to assess the capacity contribution of run-of-river hydro systems. Because the Company is winter peaking, it would be more accurate for the Company to assume average energy during the winter timeframe. My load and resource balance calculates capacity contribution based on average energy in the months of January – February.

I also assumed that the Portland Hydro Project would be renewed. The Portland Hydro Project, which consists of approximately 33 MW of run-of-river hydro capacity on the Bull Run River, was assumed to be extended and was reflected in rates in Docket No. UE 308, the 2017 Annual Power Cost Update Tariff filing. Thus, it is appropriately included in the load and resource balance in the IRP.

Renewable Resources

From the Company's load and resource balance, it is not clear what capacity contribution values were assumed for wind and solar resources. ICNU was hopeful that—following Docket UM 1719, an Investigation to Explore Issus Related to a Renewable Generator's Contribution to Capacity—the IRP would report capacity contribution values based upon the Effective Load Carrying Capability methodology. Notwithstanding, ICNU was unable to identify in the IRP where the Company calculated the contribution to peak of these resources. Absent the analysis, and based on my experience, my analysis assumes a 10% capacity contribution for wind and a 20% capacity contribution for solar. I request that the Company provide further information regarding the capacity contribution of wind and solar resources in its Reply Comments.

Distributed Solar

While the Company's load and resource balance included approximately 118 MW of capacity for non-renewable distributed generation, including the Dispatchable Stand-by Generation program, it appears to have excluded any contribution to peak associated with the approximate 65 MW of distributed solar resources included in the IRP.[7] My analysis includes a provision for capacity provided by distributed solar resources as an offset to load in the load and resource balance detailed in Confidential Attachment A.

Gas Plants Capacity

The Company appears to have slightly understated capacity available from gas resources. Based on capability in the month of January, my analysis based on the Company's most recently filed MONET model shows a slightly greater amount of capacity available from gas plants, than the 1,810 MW assumed in the Company's load and resource balance. While I have not necessarily reconciled the difference, it may be that the Company has measured the capability of gas plants in a different month of the year. In my opinion, January is the most appropriate month to measure nameplate capacity of gas plants because the Company load typically peaks when weather is coldest. In fact, it is possible that the use of average January temperatures may actually understate the capacity from gas plants because the average is not representative of the coldest hours in the month, when the Company is peaking.

In summary, based on the above analysis, existing resources will provide the Company with reasonable resource adequacy at least until the retirement of Boardman at the end of 2020. Consistent with the results of the Council's Seventh Plan, I believe that the Company should take no immediate action with respect to potential resource needs in 2021. Rather, I recommend that, prior to pursuing a physical resource, the Company should 1) continue to monitor its load forecast; 2) review availability of market imports; and, 3) continue to review demand-side options as alternatives to physical resource acquisition.

III. PORTFOLIO ANALYSIS

In addition to the problems associated with the use of the RECAP model, I believe that the portfolio analysis in the 2016 IRP is also based upon a methodology that is fundamentally flawed. Other utilities use models, such as PacifiCorp's System Optimizer model, to develop least-cost portfolios given a set of inputs. These type of models are designed to optimize the type and timing of resource additions in each portfolio for purposes of satisfying peak load requirements.

The Company's analysis, however, did not attempt to optimize the type and timing of resource additions. Rather, the Company performed a scenario analysis in the AURORAxmp model based on a series of predetermined resource portfolios, in an attempt to determine which

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[7] 2016 IRP, Volume II, Appendix D, at 384

preselected portfolio was the lowest cost. This type of analysis, however, does not necessarily reflect an optimal resource portfolio, unless one believes that the Company preselected the optimal resource portfolio. As I demonstrate below, the portfolios preselected by the Company are not optimal, particularly considering the resource need discussed in the prior section.

Similarly, the Company's attempt to consider the risk of portfolios is also analytically flawed. A risk analysis can only be said to be reasonable if it reflects a reasonable distribution of likely outcomes. While the Company considers some outcomes—such as a high gas price scenario—it did not consider portfolio performance under other potential outcomes.

Faced with these deficiencies in portfolio modeling, it is difficult to analyze the reasonableness of any aspect of the Company's proposed action plan. Notwithstanding, I have attempted to work within the Company's scenario analysis framework, using the AURORAxmp model, in order to try to determine the portfolio actions that the Company might take in order to best satisfy its potential capacity needs in coming years.

1. The Company's Portfolio Analysis Did Not Evaluate Resource Type or Timing

One purpose of the IRP is to determine the lowest cost resources to acquire, as well as the proper timing of such acquisitions. This often results in complex trade-offs between various baseload, peaker, storage, and market resources. Yet the Company's approach of evaluating portfolios is based on a limited number of pre-defined portfolios that fails to provide an adequate answer to this question of resource type and timing.

In Attachment B, I have constructed a simple Excel model that builds resource portfolios based on the load and resource table provided in Attachment A. The analysis assumes that all capacity shortfalls, after accounting for market purchases and other new resources, must be met by a combined cycle combustion turbine ("CCCT"), as a last resort. Based on this analysis, I was able to test whether it is less costly to acquire other types of resources or to rely more heavily on market purchases. I also prepared some sensitivities surrounding RPS compliance. These portfolios were input into a reference case scenario in AURORAxmp, and the resulting portfolio costs were considered in a net present value revenue requirement analysis. The results of that analysis are detailed in Table 2, below.

TABLE 2
AURORAxmp Portfolio Sensitivities (2018 – 2037)
Present Value Revenue Requirement ($000) Deltas from Portfolio 1
Reference Gas, No Carbon Constraint

		10-year PVRR	Delta	20-year PVRR	Delta
Portfolio 1	Base Case (2021 Combined Cycle Combustion Turbine)	10,836,781	-	20,639,777	-
Portfolio 2	Low Market Capacity	10,865,208	28,427	20,670,108	30,331
Portfolio 3	High Market Capacity	10,576,839	(259,942)	20,135,192	(504,584)
Portfolio 4	Wells Not Extended	10,896,214	59,432	20,875,291	235,515
Portfolio 5	Simple Cycle Combustion Turbine 2021	10,812,003	(24,778)	20,555,660	(84,117)
Portfolio 6	150 MW Direct Access	10,662,544	(174,238)	20,206,268	(433,509)
Portfolio 7	RPS Early Action (515 MW Wind 2018)	11,147,303	310,522	21,111,530	471,753
Portfolio 8	No Unbundled Renewable Energy Certificates	10,910,010	73,229	20,922,906	283,129
Portfolio 9	No Renewable Portfolio Standard	10,779,267	(57,514)	20,124,937	(514,839)
Portfolio 0	Company Preferred: Efficient Capacity 2021	11,418,357	581,576	21,689,254	1,049,478

Several interesting things can be discerned from the AURORAxmp runs detailed above. While I plan to present a fuller portfolio analysis in Final Comments, below are some of my preliminary conclusions.

- The base portfolio (Portfolio 1) in my analysis is approximately $1.0 billion less expensive, on a 20-year present value revenue requirement basis, than the Company's preferred portfolio (Portfolio 0). Thus, the Company's proposal for 850 MW of traditional capacity and 515 MW of renewable capacity could result in substantial and unnecessary costs to ratepayers.

- Portfolio 3—a portfolio which assumes 700 MW of market capacity is available to the Company—is the lowest cost portfolio. This indicates that it is crucial for the Company and the Commission to consider the amount of capacity available from the Mid-Columbia and COB markets, prior to pursuing physical resource acquisition.

- Portfolio 6 indicates that there are significant capacity benefits to remaining customers if 150 MW of load were to migrate to direct access and permanently opt-out of cost of service rates. Such a portfolio could defer the need to acquire a physical resource until 2025, saving ratepayers $433.5 million on a 20-year net present value revenue requirement basis.

- Portfolio 5 indicates that, if physical capacity is truly required in 2021, it would be more cost effective to ratepayers to acquire a smaller, Simple Cycle Combustion Turbine ("SCCT"), rather than a larger, CCCT. Ratepayers save $84.1 million in a portfolio that includes a 2021 SCCT, delaying the need to build a larger, CCCT until at least 2025.

- Portfolio 7 cost ratepayers $471.8 million more on a 20-year net present value revenue requirement basis than the base portfolio, indicating it is not a least cost strategy to pursue early action of an RPS resource at this time.

These conclusions contradict many of the conclusions reached by the Company in its IRP. These conclusions also indicate that it could cost ratepayers substantially, and unnecessarily, if the Company is to pursue the supply-side actions to acquire 850 MW of traditional capacity and 515 MW of renewable capacity. For that reason, I do not agree that the Company is justified in pursuing those supply-side actions. While the Company may be justified in acquiring a smaller, SCCT resource in 2021, the economics of that strategy are contingent on the level of market capacity actually available, as well as potential opportunities for large customers to opt out of cost of service rates. These options must be understood before a resource decision can be made.

2. Large Customer Opt-Out Should be Considered as a Resource Option

The Company assumes that no customers will elect to opt out of cost of service rates in the study period. Yet, if a large customer were to opt out of cost of service rates, it may allow the Company to avoid acquiring expensive capacity and renewable resources. Based on the portfolio analysis conducted above, ratepayers would save approximately $433.5 million, on a 20-year net present value revenue requirement basis, if 150 MW of additional load were to elect to opt out of cost of service rates. Given this potential savings, the Company should consider options that provide proper economic signals to, and eliminate barriers for, large customers who may be interested in opting out of cost of service rates. The current transition adjustment methodology, which focuses solely on short-term marginal costs, does not consider the long-term capacity benefit that the Company, and its remaining customers, receive when a large customer chooses to opt out of cost of service rates. There are also caps that have been put in place that restrict the amount of load that can migrate to direct access. Prior to building a new resource, the Company should consider raising the current direct access cap and adopting transition adjustments that consider the long-term capacity benefits associated with incremental direct access customers, while still ensuring that remaining customers are unharmed.

3. A 34-year Planning Period is Too Long

When performing the above scenarios, I limited the planning period to 20 years. A 34-year planning period is too long and puts too much weight on speculative assumptions about distant future conditions to be used for planning. The Commission's IRP guidelines do not require an analysis beyond 20 years.

Moreover, the proposed 34-year planning period is considerably longer than the 20-year planning period used in the Company's 2013 IRP. While such a long study period may present some useful information, modeling portfolio performance that far into the future is problematic and the costs of distant resources should not form the basis for near-term resource acquisitions. Resource decisions often involve a trade-off between paying more rates today, in order to achieve dispatch savings expected over a long period of time.

Forecasting conditions far into the future is inherently speculative. Ten years ago, when the Company issued the 2006 IRP for example, there was no contemplation of the rapid expansion of the Energy Imbalance Market ("EIM") throughout the West. If one goes back even further, 34 years ago to 1982, the utilities were not even contemplating the liquid bilateral markets that are ubiquitous today. The concept of something such as the EIM would have been outside of the range of any future possibility in 1982. A lot can change over a ten-year period, let alone the 34-year planning period proposed by the Company, and for that reason it makes sense to place less weight on benefits and costs expected far into the future. For purposes of making resource decisions today, a twenty-year planning period is sufficient to make informed resource decisions that form the basis for the Company's action plan. Additionally, I also gave greater weight to the first ten years of the analysis in order to reflect the greater certainty of cost predictions over this period. Thus, in the above table I also calculated levelized portfolio costs over a 10-year period, as a metric used to benchmark against 20-year results.

4. The Company's Risk Analysis is Analytically Improper

While the Company attempts to evaluate the risk profile of various portfolios, it does not properly evaluate risk. Stochastic modeling is typically used to evaluate risk associated with a resource portfolio. The aim of this type of modeling is to change model inputs based upon a distribution of expected outcomes. The Company, however, did not use a distribution of expected outcomes, and rather, relies on a skewed set of scenarios that do not properly reflect a balanced set of possibilities.

This can be noted by the failure of the Company to model a low natural gas price scenario. In addition to modeling median and "high" gas price scenarios, the Company needs to model a "low" natural gas price scenario. As noted in Figure 3.8, the Company models natural gas prices based on a reference case and a high natural gas price scenario, both of which assume prices will increase considerably in the study period. The Company, however, does not model any scenario to evaluate the impact of the very real possibility that natural gas prices will continue to remain low into the future.

The omission of a low gas price scenario is, in my opinion, a critical analytical flaw in the Company's IRP risk analysis. The exclusion of a low gas price scenario is problematic primarily because it skews the Company's risk modeling, in favor of a future state that is based on high gas prices. If one only includes two future natural gas states, a reference gas price state and a high gas price state, the median outcome of the risk modeling will be representative of prices that are between the reference state and the high gas state. That is, if only a high and reference gas prices are used, the reference case is no longer the median outcome. Thus, if a high price scenario is to be used, at a minimum, a low price scenario also needs to be modeled in order to maintain the reference case as a median outcome.

5. The Company Appears to Double Count Carbon Costs in AURORA

The Company develops a carbon price for its reference case scenario based on a report prepared by Synapse Energy Economics. The Synapse report estimates carbon costs based on the price of allowances under a mass-based state implementation plan with the new source complement. The Company notes, however, that this is not its preferred implementation plan because a source-level rate based implementation plan would result in no incremental cost to customers.

In addition to modeling carbon costs directly in AURORAxmp, however, it appears that the Company has also established a region-wide cap on carbon emissions as a constraint in the model. While not necessarily opposed to understanding the impact of potential carbon costs on portfolios, modeling a carbon price, as well as a carbon cap, did not seem to be a consistent way to model potential carbon costs. I request that the Company provide further information about how it has modeled these costs in its Reply Comments.

In addition, the Company currently expects to comply with the Clean Power Plan at no incremental cost to customers. Accordingly, the reference case should assume zero carbon costs to the Company, at least through the Clean Power Plan compliance period. In modeling prices in the AURORAxmp model, it may be appropriate to model carbon costs in the reference case forward price curve in regions where the Clean Power Plan is expected to impose additional costs. However, assigning an incremental carbon cost to the Company's portfolio in the reference case contradicts my understanding of how compliance with the Clean Power Plan might impact customers of the Company.

For these reasons, the above scenarios were analyzed in a case with zero carbon costs, though I am interested in evaluating the sensitivity of those portfolios to carbon costs in its Final Comments.

IV. RENEWABLE PORTFOLIO STANDARDS COMPLIANCE

Based upon the portfolio analysis detailed in Table 2 above, I disagree the Company is justified in pursuing early action of a renewable resource. My analysis demonstrates that early action will ultimately cost ratepayers $471.8 million on a net present value revenue requirement basis over a 20-year period. Over a 10-year period, early action will cost ratepayer approximately $310.5 million on a present value revenue requirement basis. Thus, a just-in-time RPS resource acquisition strategy is a less costly strategy—and as discussed below, a less risky strategy—for complying with RPS requirements.

1. The Company Should Adopt a Just-in-Time Acquisition Strategy for RPS Resources, Delaying RPS Resource Action Until 2030

ICNU continues to support a "just-in-time" acquisition strategy for RPS resources, including utilization of unbundled Renewable Energy Certificates ("RECs") up to the 20% statutory maximum level. Consequently, I have several concerns with the Company's proposal for early action with respect to renewable resource additions in the IRP. Not only does the Company's early-action proposal disregard a number of costs and risks associated with building a renewable resource prior to the time that such a resource is needed, an early-action strategy should not be considered in isolation from other rate impacts, including the fact that ratepayers will likely be faced with upward rate pressures as a result of replacing lost capacity associated with the retirement of Boardman.

While there may be instances where it is appropriate to pay more in rates today in order to achieve long-term rate savings, these sorts of projects with a long-term pay-back are not preferred in periods when ratepayers are already subject to substantial upward rate pressures. Additionally, the long-term rate savings should be far more certain to occur than suggested in the Company's analysis.

Moreover, early-action strategies also rely on long-term resource and planning assumptions, which carry significant forecasting risk for customers. For example, if solar costs continue on their current trajectory, the Company may be placed in a situation where it is considerably less expensive to acquire renewable energy ten years from now, than it is today. Similarly, if PTCs are ultimately extended, an early-action strategy could also cost ratepayers greatly. The rapid pace of technological change in the energy industry today creates a significant risk that acquiring new generation, renewable or otherwise, before it is needed will impose substantial stranded costs on customers.

2. The Company Should Assume that the Use of Unbundled RECs Will Delay the Need for New RPS Additions until 2030

As noted in Docket No. UM 1773, if the Company continues to rely on unbundled RECs, it will not need to acquire a new RPS resource until 2030. In the IRP, the Company attempts to model a scenario that relies on unbundled RECs to meet 20% of its RPS requirements. That portfolio, titled "Efficient Capacity 2021 20% Unbundled RECs," however, only assumes that an RPS resource can be delayed until 2025. This is because the Company assumed it could only rely on unbundled RECs over the period 2016 through 2021.

Given the low price of unbundled RECs and the Company's history of relying on unbundled RECs to meet 20% of its RPS obligation to date, it would be more appropriate for the Company to assume that it can rely on unbundled RECs over the entire IRP study period, which should delay the physical compliance need until 2030, while maintaining a sufficient REC bank balance. This analysis has been provided in Attachment C. For purposes of the portfolio analysis detailed above, I assumed that the Company could acquire RECs at a nominal levelized price of $10/MWh. Based on my analysis, the nominal levelized REC price would have to exceed $32.75/MWh (the "tipping point") before it became more economic to acquire a physical resource.

3. Early RPS Build Scenarios Should Include the Cost of Incremental Production Tax Credit Carry-Forwards

As also noted in Docket No. UM 1773, the Company currently lacks sufficient taxable income necessary to utilize all of the production tax credits generated from the Biglow Canyon and Tucannon River Wind facilities. While unused production tax credits can be "carried-forward" to be used on a future tax return, the growing balances have presented ratemaking concerns. Specifically, the Company has historically argued that it should be allowed to earn a return on the carry-forward balances at its full cost of capital.

The growth in the Company's production tax credit carry-forward balance was expected to slow, and potentially reverse, when the production tax credits generated from the Biglow Canyon facility begin to expire over the period 2018 through 2020. If the Company acquires a 515 MW wind resource in 2018, however, the growth in the carry-forward balance will not slow, but rather, will begin to accelerate at a problematic rate. As demonstrated in Attachment E, for example, I forecast that the production tax credit carry-forward balance is expected to grow to in excess of $400 million if the Company acquires a 515 MW wind facility in 2018. I also demonstrate that the return on this balance could cost ratepayers approximately $233.0 million on a present value revenue requirement basis. This additional cost has been reflected in the cost associated with an early-action strategy in the portfolio analyses detailed in Table 2, above.

The Company's portfolio analysis, however, has made no effort to quantify the impacts on rates associated with these tax attributes in the IRP. In the scenarios that rely on an early-action strategy, the Company includes no additional cost associated with its inability to utilize production tax credits on its tax return, which consequently overstates the benefits of early action to acquire the full value of the production tax credit. Given the level of risk associated with an early-action strategy, all costs and risks must be accounted for in the Company's analysis, including the cost of production tax credit carry-forwards.

V. CONCLUSION

I appreciate the opportunity to provide these comments on behalf of ICNU. I also appreciate the large amount of work and analysis conducted by the Company in preparing the IRP. Notwithstanding, there are still fundamental questions that need to be considered before taking the supply side resource actions proposed by the Company.

With respect to the renewable resource addition, I disagree with the economic analysis proposed by the Company to justify the 515 MW of near-term renewable resources, as my analysis demonstrates that it will not be beneficial to ratepayers to pursue an early-action strategy at this time.

In addition, the Company's proposal for approximately 850 MW of supply-side capacity resources should also not be acknowledged, as the Company has not justified such a substantial need at this time. Given the smaller magnitude of the capacity need demonstrated by my analysis—and the potential that the Company may be able to avoid the need altogether through existing market capability or other demand-side alternatives—my recommendation is that the 2021 need be further studied and analyzed by the Company prior to issuing an RFP.

I look forward to working with parties to further address the Company's future resource strategy.

Sincerely,

<u>/s/ Bradley Mullins</u>

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