BEFORE THE PUBLIC UTILITY COMMISSION – Revised
OF OREGON

LC 67

In the Matter of PACIFICORP, dba PACIFIC POWER
2017 Integrated Resource Plan

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Note: These comments are substantively the same as what was previously submitted. The language was clarified to hopefully ease understanding.

I. Overview

My comments on PacifiCopr's (The Company) 2017 Integrated Resource Plan (IRP) will argue that The Company has:

- Proposed new wind for economic development purposes in Wyoming that is neither needed to meet its Oregon obligations – or its obligations anywhere else in its system;
- Proposed new investments in wind, as a carbon reduction strategy, ignore less costly and more successful ways of reducing carbon emissions;
- Proposed new investments have virtually non-existent potential benefits for its Oregon retail customers.

Two other less significant points will be noted:

- Incorrectly argued that renewables will dominate new construction nationally; and,
- The Company omits any discussion of their B2H transmission project.

II. The Company has proposed new wind for economic development in Wyoming that is neither needed to meet its Oregon obligations – or its obligations anywhere else in its system

As staff's final comments indicate, "PacifiCorp has repeatedly stated that these resources are not being added to the system to meet a regulatory requirement such as the RPS [Renewable Portfolio Standard]…"[1] that its need for new generation is non-existent over the next 10 years.[2] The absence of any pressing

1 "Staff Final Comments," BEFORE THE PUBLIC UTILITY COMMISSION OF OREGON LC 67, In the Matter of PACIFICORP, dba PACIFIC POWER, 2017 Integrated Resource Plan,
2 This conclusion is based on Tables 1.2 and 1.3 on p.11 of PAC's 2017 IRP. Tables 5.14 (p. 91) and 5.15 (p. 92) provide more detail on PAC's summer and winter load-resource balances, respectively.

need for new generation was echoed in testimony filed by the Citizens Utility Board (CUB).[3] Staff is correct in stating, "Acknowledging action to acquire RPS compliant resources or energy or capacity resources requires a regulatory, energy, or capacity need. The two concepts work together; the long-term plan is developed, tested, and consistently updated to the point that near-term action is necessary to meet need."[4]

Table 1.2 on page 11 of The Company's IRP indicates that between existing capacity and market purchases, The Company is surplus in summer for each of the years throughout the 10-year period used in its construction. Table 1.3 shows The Company even more surplus in winter.

Figures 1.11 and 1.12 on page 12, which illustrate on-peak and off-peak, respectively, indicates very few times when The Company goes to market to make purchases to meet load.

In comments filed in docket LC66, I argued that the utility must first identify that a need exists prior to acquiring an asset. If this standard is not upheld, it undermines this essential prior requirement for the utility to determine need before proceeding forward with an investment with an eye towards rate basing that cost. If there is no need, the economics of a proposed purchase is not pertinent."[5] That necessary condition is as true here as it was at the time when those comments were filed in LC66.

Once again, Hoecker points to language in a case from New York state that is clarifying, "The New York Public Service Commission articulated the standard: Consumers should not pay in rates for property not presently concerned in the service rendered, unless emergency or substitute service; and in studying these two exceptions the economic factor should be carefully considered.

(1) Conditions exist pointing to its immediate future use; or
(2) Unless the property is such that it should be maintained for reasonable."[6]

He notes that the used and useful principle is "…invoked to protect consumers from bearing certain risks associated with speculative investments.[7]

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3 "COMMENTS OF THE OREGON CITIZENS' UTILITY BOARD," BEFORE THE PUBLIC UTILITY COMMISSION OF OREGON LC 67, June 23, 2017. *See*: http://edocs.puc.state.or.us/efdocs/HAC/lc67hac11433.pdf
4 "Staff Final Comments," p. 13.
5 "RESPONSE TO "STAFF REPORT FOR THE AUGUST 8, 2018 PUBLIC MEETING" BEFORE THE PUBLIC UTILITY COMMISSION OF OREGON LC 66 In the Matter of PORTLAND GENERAL ELECTRIC COMPANY, 2016 Integrated Resource Plan, p.1.
6 James Hoecker, "USED AND USEFUL": AUTOPSY OF A RATEMAKING POLICY," Energy Law Journal, Vol. 8:303, 1987, p. 306.
7 Ibid, p.333.

As Hoecker describes, the concept has been used in the context of balancing ratepayer and investor interests. Looking down the road, the Commission may decide that there is a compelling public interest in acknowledging The Company's proposed plan to acquire renewables ahead of need due to the compelling public interest in cutting total carbon emissions. However, there are strong arguments to not do so. In addition, the burden of proof is on The Company, not Staff or any other party to this docket.

III. Proposed new investments in wind, as a carbon reduction strategy, ignore less costly and more successful ways of reducing carbon emissions.

While there is no reasonable debate about anthropogenic climate change, nonetheless, it's incumbent on all involved to economize on resources used, especially CO2 emissions.

While the Commission has no authority to countermand the legislature's actions, or the governor's signature of SB1547, that increased out-year RPS, investing in new renewables to cut CO2 emissions is very costly. What a higher RPS threshold does is require a higher fraction of a utility's retail sales must be met through some combination of buying renewable energy credits (REC) or building renewables.

Table One illustrates what it more often left unaddressed – how costly it is to rely on investment in new renewables to cut CO2 emissions from electricity generation. These emission reductions and costs were developed by the Northwest Power Planning Council (NWPPC) as part of the analysis contained in

Table One
Average Cumulative Emissions Reduction and Present Value [a]

Policy Alternative	Cumulative Emission Reduction (MMT)	Incremental ASC Net Of Carbon Revenues (2012$ billions)	Present Value Average Cost/Metric ton of Carbon Emissions Reduction (2012$/Metric Ton)
A: Mid - Range Carbon Adder [b]	351	(3.9)	(11)
B: A + C	377	8.9	23
C: Retire Coal	197	15.4	78
D: B + No New Gas	430	43.2	100
Savings w/Current Technology [c]	201	34.2	170
F: RPS at 35%	132	46	349

a. Existing Policy means existing state law (prior to SB1547-B) across the Pacific Northwest.
b. SCC Mid-Range is the Social Cost of Carbon (SCC) of $40.99/metric ton in FY2016 and increases annually to $60.41/metric ton by FY2035.
c. All existing coal plants are retired along with CT's with heat rates greater than 8,500 btu/MWh.

7th Power Plan, released in 2016.[8]

In that analysis, which pre-dated passage of SB1547, and therefore used the RPS then in place in each of the Northwest states, increasing RPS to 35% resulted in the smallest net reduction in CO_2 emissions. This can be seen in Table One by comparing the cumulative reduction in CO_2 for Policy F (132 MMT) to the results for the five other policies. If that wasn't bad enough, Policy F came in at the highest cost ($46 billion), as measured by increase in average system cost (ASC). As a result, the cost per unit of CO_2 reduction from investing in new renewables to cut CO_2 emissions is significantly more costly than any of the other CO_2 reduction policies at $349/MMT (metric ton) of CO_2 reduction.

If The Company's proposed investment in re-powering wind, new wind, and new transmission is driven by concern over CO_2 emissions, the results in Table One suggest that shutting coal plants (Policy C) leads to a greater reduction in CO_2 emissions of 197MMT(as compared to 132MMT for new renewables) at a cost of $15.4 billion rather than $46 billion. Therefore, the cost per unit of CO_2 Reduction from closing coal plants $78/MMT, which is substantially lower than the $349/MMT for new renewables.

Furthermore, building new renewable ahead of need does not mean that The Company is delivering more green energy to its Oregon retail customers. The Company is one part of a much larger integrated system known as the Western Interconnection (WECC). That system includes Mexico, the two Western most provinces in Canada, and fourteen Western states. This is the case because numerous transmission pathways exist between its two balancing authorities, PACE and PACW, and the rest of WECC. The electrons coursing through WECC's extensive transmission system means electrons from coal-fired generation, of which there is approximately 200,000GWh, should be assumed to flow to all retail loads in the system.

At the heart of this problem is the difference between the physical power system and the contractual and regulatory framework that allocates power system costs. The term "leakage" is used to describe that disconnect. In a nutshell, while two parties may reach agreement on contract terms of a power purchase, in an AC power system, the electrons flow down all paths simultaneously. A buyer may argue that only green power is being used to operate their business, but the physical power flows are determined by physics, not contracts. Contracts will help determine what costs The Company must recover but not what electrons flow from which generators to any given customer.

It's easy to get confused about the issue of leakage. At least some of the parties involved in the behind-the-scenes negotiations that resulted in HB4036 (and its

8 The analysis performed by NWPPC and a discussion of the limitations of SB1547 are discussed in this journal article: Robert J. Procter, "Cutting Carbon Emissions from Electricity Generation, The Electricity Journal, Volume 30, Issue 2 , March 2017, Pages 41-46

Senate version, SB1547) believed that as long as The Company and Portland General Electric shut down owned coal and have no contracts for coal deliveries to their BA's, that Oregon retail electricity deliveries are free of coal. Such is not the case.

Resolutions advocating 100% renewables, such as the one that Portland and Multnomah County have adopted do not provide sufficient justification to acknowledge The Company's proposal to invest in new renewables. Staff to Portland's mayor defended the resolution be referencing a study by Mark Jacobson at Stanford that argues it is economic for 139 countries to wholly switch out of fossil fuels and into electricity and hydrogen for every use by 2050.[9] However, in addition to a number of heroic assumptions in that work, one of its numerous shortcomings is its omission of a sub-hourly evaluation of how the power system functions as more and more renewables come on line. Heard[10] and Loftus[11] both reject Jacobson's 2050 electricity forecast under WWS-only. One of the reasons is the proportion of people living without access to electricity means that twice as much energy will likely be consumed by mid-century. Loftus notes that energy intensity also affects forecasted energy use it declined 0.9%/year over the period 1990-2005, while Jacobson's analysis assumes annual reductions exceeding 10%. Loftus concluded that no study he reviewed presented sufficient detail on how to cut carbon emissions from the industrial and transportation sectors. Finally, an article by Clack et. al. identified even more limitations in Jacobson's work.[12]

As staff argues in its final comments, the proposed wind acquisitions "…would largely displace resources, such as front office transactions, for which PacifiCorp receives no rate of return. Finally, these additional resources would not lead to replacement or early retirement of any of PacifiCorp's 24 existing coal fired units and would not serve to "decarbonize" PacifiCorp's system."[13]

IV. Proposed new investments have virtually non-existent potential benefits for its Oregon retail customers.

9 Mark Z. Jacobson et. al., "100% Clean and Renewable Wind, Water, and Sunlight (WWS) All-Sector Energy Roadmaps for 139 Countries of the World," June 2017, See: http://web.stanford.edu/group/efmh/jacobson/Articles/I/USStatesWWS.pdf

10 B.P. Heard, B.W. Brook, T.M.L. Wigley, and C.J.A. Bradshaw, "Burden of Proof: A Comprehensive Review of the Feasibility of 100% Renewable Electricity Systems," Renewable and Sustainable Energy Review, 76(2007), p. 1122.

11 Peter J. Loftus, Armond M. Cohen, Jane C. S. Long, and Jesse D. Jenkins, "A critical review of global decarbonization scenarios: what do they tell us about feasibility?" Climate Change, Nov. 6, 2014.

12 "Evaluation of a proposal for reliable low-cost grid power with 100% wind, water, and solar," Journal of the National Academy of Sciences, vol. 114 no. 26 > Christopher T. M. Clack, 6722–6727, doi: 10.1073/pnas.1610381114. *See*: http://www.pnas.org/content/114/26/6722.full

13 "Staff Final Comments," p. 14.

Table Two is excerpted from testimony filed by CUB.[14] It illustrates calculations made by The Company for repowering wind. It corresponds to The Company's Table 8.6, Cost/(Benefit) of Repowering Wind. One row of The Company's table has been removed in order to more clearly focus on their calculations consistent with the traditional IRP 20-year planning horizon. However, since rates are based on nominal dollars over the timeframe used in a given rate filing, which is significantly shorter than the 20-yr. planning horizon used in the IRP, looking at PV benefits over 20 years distorts the potential benefit to customers.

Table Two
Present Value (Benefits)/Costs to PacifiCorp System

Total Cost/(Benefit) ($ million)	System Optimizer	PaR Stochastic Mean					
	Mass B	Mass A			Mass B		
	Medium Gas	Low Gas	Medium Gas	High Gas	Low Gas	Medium Gas	High Gas
Change from OP-NT3 (2036)	($66)	($51)	($66)	($152)	($48)	($64)	($143)

Note: Numbers in parenthesis represent benefits since they are reductions in revenue requirements, holding all else constant.

To more accurately reflect potential gains to customers via rates, those PV results were levelized using a 20-year timeframe and The Company's discount rate, 6.57%. Table Three contains the levelized results.[15]

Table Three
Levelized (Benefits)/Costs to Retail Customers on PacifiCorp System

Levelized Cost/(Benefit) ($ million)	System Optimizer	PaR Stochastic Mean					
	Mass B	Mass A			Mass B		
	Medium Gas	Low Gas	Medium Gas	High Gas	Low Gas	Medium Gas	High Gas
Change from OP-NT3 (2036)	($6.02)	($4.65)	($6.02)	($13.87)	($4.38)	($5.84)	($13.05)

14 "COMMENTS OF THE OREGON CITIZENS' UTILITY BOARD," BEFORE THE PUBLIC UTILITY COMMISSION OF OREGON, LC 67, In the Matter of PACIFICORP, dba PACIFIC POWER, June 23, 2017, p. 17.

15 Levelizing the PV estimates creates a stream whose sum equals the PV amount. It essentially generates a equal annual value. The values in Table Two provide a reasonable approximation of the (benefits)/costs to customers assuming full pass-thru into rates, all else held equal.

Since PAC's retail sales in Oregon account for roughly 25% of its total retail sales, Table Four contains the fraction of the values appearing in Table Three. What these results indicate is that the calculated benefit on an annual basis for The Company's total Oregon retail customer base ranges between roughly $1.2 million and $3.3 million.

Table Four
Total Levelized (Benefits)/Costs to PacifiCorp's Oregon Retail Customers

Oregon's Share of Levelized Cost/(Benefit) ($ million)	System Optimizer	PaR Stochastic Mean					
	Mass B	Mass A			Mass B		
	Medium Gas	Low Gas	Medium Gas	High Gas	Low Gas	Medium Gas	High Gas
Change from OP-NT3 (2036)	($1.51)	($1.16)	($1.51)	($3.47)	($1.10)	($1.46)	($3.26)

Spreading the values in Table Four across months and dividing the result by the number of its Oregon retail customers in 2016, and converting from millions of dollars to dollars, provides a clearer picture of the impact of the proposed investment on revenue requirements The Company would need to collect monthly from its Oregon retail customers. These results demonstrate that, on average, the maximum potential benefit to each of The Company's Oregon retail customers from re-powering wind ranges between $0.16 and $0.50 per month.

Table Five
Monthly Change in Revenue Required from Each Oregon Retail Customer
(Re-Powered Wind)

Average monthly Share per Oregon customer, (Levelized Cost/(Benefit), $)	System Optimizer	PaR Stochastic Mean					
	Mass B	Mass A			Mass B		
	Medium Gas	Low Gas	Medium Gas	High Gas	Low Gas	Medium Gas	High Gas
Change from OP-NT3 (2036)	($0.22)	($0.17)	($0.22)	($0.50)	($0.16)	($0.21)	($0.47)

If instead of beginning with their Table 8.6, we begin with Table 8.11, Cost/(Benefit) of Repowering Wind Combined with Transmission and New Wind, the corresponding results to those in Table Five appear in Table Six.

Table Six
Monthly Change in Revenue Required from Each Oregon Retail Customer
(Re-Powered Wind, New Wind, New Transmission)

Average monthly Share per Oregon customer, (Levelized Cost/(Benefit), $)	System Optimizer	PaR Stochastic Mean					
	Mass B	Mass A			Mass B		
	Medium Gas	Low Gas	Medium Gas	High Gas	Low Gas	Medium Gas	High Gas
Change from OP-NT3 (2036)	$0.24	$1.02	$0.67	($1.04)	$1.03	$0.65	($1.03)

Referring to Table Six, the levelized monthly (benefit/cost) for each of The Company's Oregon retail customers ranges between a cost increase of roughly $1.03 to a benefit of about $1.04.

V. Two Other Issues

The Company argues that "Federal and state tax credits, declining capital costs, and improved technology performance have put wind and solar "in the money" in areas of high potential. Wind and solar will therefore dominate United States capacity additions for the next decade." [16]

Its puzzling why The Company would make that argument, unless its purpose was to foster greater support for its preferred portfolio, which it knew was tenuous at best. As Table Seven illustrates, renewables do not dominate U.S. capacity expansion over the next decade.

Table Seven
Generation in Various Stages of Development, U.S.[17]

	Total (MW)	Fossil Fuel (%)	Renewable (%)
Under Construction [a]	43,551	41	46
Permitted [b]	48,551	60	40
Pending Application [c]	79,263	43	41
Proposed [d]	200,273	26	65

Note: Rounded to nearest whole number. Nuclear excluded.

a. "TABLE 2.1 Plants Under Construction, Fuel Type, America's Electricity Generation Capacity 2015 Update, p. 11.
b. Ibid, "TABLE 2.2 Permitted Plants, Fuel Type," p. 12.
c. Ibid, "TABLE 2.3 Pending Application Plants, Fuel Type," p. 12
d. Ibid, "TABLE 2.4 Proposed Plants, Fuel Type," p. 13.

[16] See p. 25 of PAC 20-17 IRP.
[17] "TABLE 1.3 Generation Capacity Additions, 2008 – 2014," America's Electricity Generation Capacity 2015 Update, American Public Power Association, p. 8.

That table illustrates th amount of electricity-generating plants in various stages of development, as of 2015. While renewables do represent a significant portion of plants at the proposal stage, that is the most speculative stage of development.

Further, The Company omitted any discussion of its B2H transmission project. It did note that discussing B2H is beyond the scope of its 2017 IRP. If that is the case, does that then mean no costs associated with B2H will appear in any subsequent rate filing?

The B2H is a segment of The Company's long-term strategic goal of completing about $8 or $9 billion in bulk electric transmission development often referred to as the Gateway West Project. The B2H line would allow it to move output from the wind in Wyoming to California and the Southwest. Since The Company has a majority share of B2H, addressing the costs, risks, and role of B2H project in its 2017 IRP seems appropriate.

VI. Conclusions and Recommendations

Absent an affirmative demonstration of a system need for new near-term investments in intermittent generation and supporting transmission, the OPUC must resist acknowledging those elements of its preferred portfolio.

If The Company had demonstrated a need for capacity and/or energy in its IRP, then it would be incumbent on the OPUC to work to balance potential benefits to customers with potential risks. However, the Company failed to demonstrate a need for new near-term investments upwards of $2.5 billion on re-powered wind, new wind, and new transmission.

Further, for the reasons laid out in section III, acquiring new wind as a de-carbonization strategy is to pursue a path that would produce few benefits in the form of reduced carbon emissions while exposing customers to the risks associated with investments totaling roughly $2.5 billion.

If The Company wishes to pursue a de-carbonization strategy, the OPUC should direct it to evaluate the risks and benefits to customers in terms of both reduced CO2 emissions, as well as the delivered cost of electricity, that would result from shutting down some or all of its coal fleet earlier than planned.

As to the issue of cutting its carbon emissions, Table One provides insights into the regional impacts of installing more intermittent renewables versus shutting down coal generation when the objective is cutting carbon emissions. Retiring coal (Policy C) resulted in 65MMT greater reductions in carbon emissions than increasing renewables via setting a higher RPS, (Policy F) Policy F. While that isn't a huge gain when compared to other carbon reduction policies, it comes at a significantly reduced average system cost of roughly $25 billion. What is significant is the lower cost per unit of reduced CO2 emissions from closing coal plants, at $78/MMT of CO2 reduced, versus $348/MMT of CO2 reduced for new intermittent generation.

Further, as Tables Five and Six demonstrate, its Oregon retail customers wouldn't reap any meaningful benefit from the proposed investments. This is contrary to The Company's assertion that unless the OPUC acknowledges its action plan, its Oregon customers would miss an opportunity to benefit from the investments.

It is important to keep in mind that the IRP process is designed to be a framework for consistently evaluating competing approaches to meeting load while maintaining reliability. When The Company performed its analysis, it concluded that there was not a need for new capital investments in intermittent renewables. Attempting to shift the focus to one of carbon reduction isn't supported by the analysis contained in its IRP.

The Company's desire to re-power existing wind, develop new wind in Wyoming, and make needed transmission investments can only be seen as efforts by The Company to augment its rate base to enhance its stock price and, in turn, enhance returns to its investors. It is not the role of the OPUC to assist The Company in sustaining or enhancing its stock price. Surely, the OPUC has an obligation to not establish roadblocks that impede The Company's recovery of costs prudently incurred. However, that raises an important question: Should the OPUC's assist The Company's effort for new near-term investment of approximately $2.5 billion when no need has been demonstrated? The answer must be no.

It is also worth noting that The Company remains free to make the investment for what it clearly states are economic reasons. If it truly believes the potential benefits sufficiently outweigh the risks, let its investors both bear the risk and reap all the gains. Nothing the OPUC does forestalls The Company from doing what it says it wants to do – take advantage of an economic opportunity. Such a strategic decision on The Company's part lies outside the bounds of OPUC oversight. The absence of such a choice on the part of The Company speaks volumes.

This concludes the comments of Robert J. Procter.

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