**BEFORE THE PUBLIC UTILITY COMMISSION
OF OREGON**

LC 67

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

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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 this system;
- Proposed new investments in wind as a carbon reduction strategy ignoring less costly and more successful ways of reducing carbon emissions;
- Proposed new investments with almost non-existent potential benefits in the form of lower rates to its Oregon retail customers while the risk exposure is great.

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 this 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…"[1] that its need for new generation is non-existent over the next 10 years.[2] The absence of any pressing need for new generation was echoed in testimony filed by the Citizens Utility Board (CUB) on (date).[3] Staff is

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.

3 CUB testimony

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]

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

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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.

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 went un-evaluated

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 Renewable Performance Standards (RPS), using RPS 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 or building renewables.

Table One illustrates what it more often left unaddressed – how costly it is to rely on 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 its 7th Power Plan, released in 2016.[8]

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.

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

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 CO2 emissions. This can be seen in Table One by comparing the cumulative reduction in CO2 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 of these two results, the cost per unit of CO2 reduction from investing in new renewables to cut CO2 emissions is significantly more costly than any of the other CO2 reduction policies at $349/MMT (metric ton) of CO2 reduction.

If The Company's proposed investment in re-powering wind, new wind, and new transmission is driven by concern over CO2 emissions, the results in Table One suggest that shutting coal plants leads to a greater reduction in CO2 emissions and at a significantly reduced cost. In contrast, closing coal plants (Policy C) resulted in a greater net reduction in CO2 emissions (197MMT) than was obtained through building new renewables (132MMT), and at a fraction of the cost ($15.4 billion). As a result of the greater amount of CO2 reductions and the significantly lower cost results in a cost per mega-ton of CO2 reduced of $78/MMT rather than $349/MMT for the new renewables strategy.

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.

The Company has two BA's, PACE and PACW. Numerous transmission pathways exist between its BA's 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.

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 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 Is not sufficient reason to acknowledge The Company's proposal to invest in new renewables.

It is important to have some appreciation for the type of analysis that was relied on to support that resolution. 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.

For the residential sector, Jacobson implicitly forecasts 2050 loads to drop 26% under his wind, water, sun only portfolio (WWS-only). That is, for the U.S., he forecasts 249,200MW under WWS-only compared to 336,800MW under Business-as-Usual (BAU) combined fossil-renewable portfolio. It's difficult to imagine how the direct use of natural gas for space and water heating under BAU is less efficient than WWS-only. 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.

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."[12]

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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 "Staff Final Comments," p. 14.

IV. Proposed new investments with almost non-existent potential benefits in the form of lower rates to its Oregon retail customers while the risk exposure is great.

Table Two is excerpted from testimony filed by CUB.[13] 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

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 from the action being evaluated 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.[14] On an levelized (i.e., annualized) basis, the potential benefits to all of The Company's retail customers of its proposed wind re-powering are quite minimal. Even under high gas prices, the annualized benefits – which is closer to what retail customers might experience, are only roughly $13 - $14 million. These estimates are for its entire retail load, not the portion that exists in Oregon. Since the OPUC's focus is on the fraction of those benefits that could potentially accrue to The Company's Oregon retail customers, the results in Table Three must be multiplied by 25%. Those results

13 "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.

14 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.

Table Three

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)

appear in Table Four. 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

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)

Table Five contains estimates of the levelized monthly benefits to each of The Company's Oregon retail customers, expressed in dollars. These results

Table Five

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)

demonstrate that the average maximum monthly potential benefit to each of The Company's Oregon residential customers from re-powering wind ranges between $0.16 and $0.50.

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 above appear in Table Six.

Table Six

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 customers ranges between a cost increase of roughly $1.03 to a cost reduction 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." [15]

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. That table illustrates electricity-generating plants in various stages of development, as of 2015. While renewables do represent a significant portion of plants that have been proposed, 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?

[15] See p. 25 of PAC 20-17 IRP.

Table Seven
Generation in Various Stages of Development, U.S.[16]

	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.

Yet, 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 over $2 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 its coal fleet earlier than planned.

[16] "TABLE 1.3 Generation Capacity Additions, 2008 – 2014," America's Electricity Generation Capacity 2015 Update, American Public Power Association, p. 8.

As to the issue of cutting carbon its 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 CO2 emission reduction from closing coal plants, at $78/MMT of CO2 reduced, versus $348/MMT of CO2 reduced.

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 wasn't 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 be seen as efforts by The Company to augment its rate base to help enhance its stock prices and 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 reasonably 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 as been demonstrated? The answer must be no.

The Company remains free to make that 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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