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October 8, 2009

Via Electronic and First Class Mail

Filing Center
Public Utility Commission
P.O. Box 2148
Salem, Oregon 97308-2148

Re: In the Matter of PacifiCorp, dba Pacific Power, 2008 Integrated Resource Plan, PUC Docket No. LC 47

Dear Filing Center:

Enclosed please find an original and one copy of Opening Comments of The Renewable Northwest Project and The Citizens Utility Board.

Yours truly,

/s/ John W. Stephens

John W. Stephens

JWS/mec
cc: Service List
Enclosures

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BEFORE THE PUBLIC UTILITY COMMISSION OF OREGON

LC 47

In the Matter of	)	OPENING COMMENTS
	)	OF THE RENEWABLE
PACIFICORP, dba PACIFIC POWER	)	NORTHWEST PROJECT AND
	)	THE CITIZENS' UTILITY
2008 Integrated Resource Plan.	)	BOARD
	)	

The Renewable Northwest Project (RNP) and the Citizens' Utility Board (CUB) together submit these opening comments on PacifiCorp's 2008 Integrated Resource Plan (IRP or Plan). We believe that PacifiCorp has once again engaged in an ambitious IRP analysis that is in some ways among the most sophisticated in the nation. However, we have significant concerns about several areas of the Plan that are detailed below.

First, PacifiCorp's wind integration analysis is flawed, resulting in a rate that is likely twice the actual cost. This has both ratemaking implications for Oregon customers as well as regional implications for wind development. Second, while PacifiCorp's modeling of greenhouse gas emissions is robust and continues to improve, the Plan does not appear to significantly reduce actual carbon emissions. This falls in the category of a variation on RNP's longtime planning mantra Planning is Good, but Doing is Better. Which is: **Modeling CO_2 is Good, but Reducing CO_2 is Better**.

We recommend that the Commission not acknowledge PacifiCorp's wind integration cost study and direct the Company to complete a new study within 3 months of the close of this docket. RNP and CUB are both continuing to review the IRP and related data requests and may have additional recommendations in reply comments.

I. Wind Integration Analysis

Overview

PacifiCorp's treatment of wind generation integration costs stands out as a major flaw in the Plan. At the outset, PacifiCorp unaccountably, and against the advice of stakeholders, abandoned its earlier analyses of wind integration costs in favor of adopting another utility's preliminary estimate of their own wind integration costs. PacifiCorp did not begin its own wind integration analysis until after the IRP studies were completed using the adopted wind integration cost.

The revised analysis had the explicitly stated purpose of developing "a methodology to support the costs associated with resource portfolio analysis for the IRP[1]...." The

[1] PacifiCorp 2008 IRP Appendix F page 269.

analytical techniques used in the study represent a radical departure from earlier PacifiCorp studies, those of other Northwest utilities, and studies across the US and internationally. The new methodology was developed without involving outside experts or stakeholders despite repeated urging by OPUC Staff and stakeholders to do so. Flaws in the methodology are relatively basic and easily addressed, but are so fundamental that PacifiCorp's stated results cannot be accepted as a serious approximation of their wind integration costs. The present study doubles PacifiCorp's earlier projections of wind integration costs, and we believe probably overstates the costs by a factor of two or more.

Specific Concerns

1. The most fundamental shortcoming in PacifiCorp's methodology is that the variability and uncertainty introduced by wind is considered separately from the variability and uncertainty already on the power system due to load. The reason this is important is that the forecast errors and short-term (less than one hour) variability of wind and load are not normally correlated with one another. This is a crucially important issue, but not a new one.

   Every wind integration study of which we are aware has netted wind against load in deriving the reserve requirement, including PacifiCorp's previous analyses dating back to 2003, as well as the analyses of Idaho Power Company, Avista, and Portland General Electric. The point is well documented in wind integration literature: "The requirement of extra reserves is quantified by looking at the variations of wind power production, hourly and intrahour, together with load variations and prediction errors." Ackermann, "Wind Power in Power Systems", [p. 158, Wiley, 2005. Exhibit 1]. Similarly from another source, "The increase in short term reserve requirement is mostly estimated by statistical methods combining the variability or forecast errors of wind power to that of load and investigating the increase in the largest variations seen by the system." [IEA Task 25 Final Report, page 13, 2009. Exhibit 2].

   In cases where the wind variability is small in absolute (MW) terms compared with load, the incremental need for reserves is not significant. On the other hand, if the load and wind variability (or uncertainty) are comparable, the incremental need for reserves is not double, but approximately 40% higher. This is due to the fact that the reserve requirement is proportional to the standard deviation of the variability.

   PacifiCorp's implicit assumption that the reserve requirement is independent of the load would only hold if the load variability and uncertainty are small fractions of the wind variability and uncertainty. PacifiCorp acknowledges that it has no information suggesting this is the case. [Response to RNP Data Requests 5 and 6. Exhibit 3.] In addition, PacifiCorp's response in RNP Data Request 10 makes clear that PacifiCorp offers no basis at all for failing to net load and wind to determine reserve requirements. [Exhibit 4.]

2. PacifiCorp's representation of wind generation from new wind projects—especially on the east side—significantly overstates the reserve requirement. In past wind

studies, PacifiCorp represented new wind projects as time-shifted time series from existing projects. The time shift preserved some correlation between existing and new projects, without assuming 100% correlation between the fleet additions and the existing fleet. Representing the new wind projects using a multiplicative constant establishes a higher correlation between the new wind projects and the existing ones than is reasonable.

This effect may not be significant for the west side projects, because the capacity of the incremental projects is a relatively small fraction of the existing projects. On the east side however, the nameplate additions are a multiple of the existing projects and the effect is very significant—especially on the shorter timescale (ten minutes) where correlations among even relatively nearby projects tend to be relatively small.

PacifiCorp's response to RNP Data Request 8 suggests that new projects will be sited close enough to existing projects that the correlations among existing projects can be used "to help specify correlations between existing and new projects." [Exhibit 5.] RNP agrees that the existing correlations are useful, but PacifiCorp did not use them to help specify correlations between the new projects and existing ones; instead, they implicitly assumed 100% correlation between matched pairs of existing and new projects. The Company goes on in its Response 8 suggest that the uncertainty in the locations of new projects renders their assumption reasonable. We believe the opposite is true. No two existing projects exhibit 100% correlation, and only an extraordinary and almost unimaginable set of circumstances would cause the correlations to be any higher than PacifiCorp has assumed.

The reason this is important is that diversity in wind project output (the extent to which output levels are not correlated) tends to reduce both the variability and uncertainty in wind generation. Aggregated persistence forecasts are more accurate for uncorrelated projects than for correlated projects. In underestimating wind generation diversity, PacifiCorp's methodology essentially ensures the resulting reserve requirements are overestimated by a significant amount. At a minimum, PacifiCorp should represent new project output by time-shifted levels at existing projects, adjusting the time shift until the correlation with a selected nearby project reaches a level similar to that seen between existing adjacent projects.

3. PacifiCorp's assumption that all balancing purchases entail market transactions and market transaction costs is not supported by, and is not consistent with, previous PacifiCorp studies, or other utility studies. Earlier studies by PacifiCorp assumed a constant $0.50/MWh cost to all market transactions. The present study deviates significantly from the previous assumption, substantially increasing the resulting estimated inter-hour balancing costs.

   PacifiCorp's assumption about higher hour-ahead trading costs is not well documented. However, even given the new higher costs, it is not correct to assume that all imbalances are settled in the markets. For example, if the wind generation is unexpectedly high during a heavy load hour, PacifiCorp will likely have the ability to reduce generation somewhere on its system (e.g., on a hydro or fossil unit) without incurring a market transaction cost.[2] Similarly, if a shortfall of wind from the expected amount occurs on a light load hour, it would be unusual for PacifiCorp to need to rely on markets to make up such a difference. The net effect of PacifiCorp's assumption is an overall overestimate of the inter-hour costs by a significant amount.

PacifiCorp suggests that adjusting resources for the realities of load, generation, and market prices for the next hour is never economic as it results in an "uneconomic dispatch," and appears to imply that "clearly the choice is to transact in the market." [Response to RNP Data Request 9. Exhibit 6.] This is an unaccountable response, suggesting that the Company can never save more by changing operations at its own projects than incurring a transaction cost to operate resources on another system. The fallacy of this argument is easily illustrated with an example:

> Assume that the prevailing market price is $50/MWh and PacifiCorp has optimized its resources such that the most expensive resource operating has a marginal cost of $50/MWh. If the wind generation exceeds the plan for that hour and PacifiCorp finds itself with an additional 150 MWh for that hour, PacifiCorp may choose to back down its $50/MWh resource to save $7,500 on that hour, or sell the 150 MWh into the market for $42.50/MWh ($50/MWh less 15% transaction cost) and earn $6,375. In this case it is clear that the economic choice is to back down the owned resource and not transact in the market.

There may be times when the conditions of the example do not hold (PacifiCorp has no resource operating at the marginal rate, or is at minimum generation levels), but the statement that it is always more economic to transact in the market is simply not credible, nor supported by PacifiCorp: "There is no data or analysis to show that PacifiCorp resolves all imbalances through market transactions." [Response to RNP Data Request 9. Exhibit 6.]

4. PacifiCorp's insistence that day-ahead balancing needs always be rounded up is difficult to understand and is not supported. If PacifiCorp seeks to balance the system as closely as possible, it should round off the day-ahead purchase and sales requirements. Rounding up would make PacifiCorp routinely surplus when purchasing, and routinely deficit when selling (assuming that's what they mean[3]).

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[2] It is possible that there might be some cost (or benefit) associated with operating a thermal or hydro unit at a different point in its power efficiency curve. However, this would not be the same order of magnitude as the 10-25% market transaction costs assumed in PacifiCorp's analysis.

[3] In conversations, PacifiCorp could not explain precisely what rounding up their market transactions meant. As stated in the IRP document, it appears that PacifiCorp rounded up purchases (making them more surplus) and rounded up sales (which would make them more deficit). However in conversation, PacifiCorp staff suggested that the operation was necessary to ensure the company is not short. This implies rounding up purchases and rounding down sales. In either case, the assumption improves neither the economics nor reliability. For example, systematic over-purchasing risks CPS 2 violations in light load hours. For reliability purposes, PacifiCorp should err on the over-purchase side during heavy load hours and under-purchase on light load hours. This does not seem to be what they meant and would not be economic in any case.

For reliability purposes, it would be reasonable to round up purchase requirements over heavy load hours to minimize the chance of being short over critical hours. Conversely, it might be reasonable to set the balance slightly short on light load hours to reduce the risk of running into minimum generating requirements. However, making the system over-long and over-short randomly serves only to unnecessarily add to the need for, and cost of, relatively expensive hour-ahead balancing services.

5. All other wind integration studies we are aware of, including PacifiCorp's earlier analysis, show an increasing cost (on a per megawatt-hour basis) of wind integration as wind generation is added to the system. PacifiCorp only examined the most extreme level of wind penetration, reached in 2021, and uses it to justify the wind integration cost ascribed throughout the study horizon. PacifiCorp should either derive a levelized cost reflecting the increasing cost through time or pick a cost level based on an average level of wind development through the study horizon. Using a level determined for 2021 throughout the study is in itself a considerable overstatement of the wind integration costs actually incurred.

6. PacifiCorp's wind integration presentation of 8/31/2009 as well as its data request response suggest that the wind forecast assumption for the analysis was based on the average wind generation level between one and two hours prior to the beginning of each operating hour. [Response to RNP Data Request 3. Exhibit 7.] The IRP Appendix F states that the current state of forecast accuracy is a 40-45 minute persistence forecast. The difference between PacifiCorp's stated forecast capability and that relied upon in its analysis leads to a significant overestimate of the hour-ahead forecast error, and the corresponding intra-hour reserve requirement. Further, it is clear from experience in the BPA rate case that the state of the art for wind forecasting of Northwest wind projects is closer to the 30-minute persistence levels achieved by employing meteorologists to forecast wind in real time. Given the expense PacifiCorp associates with the forecast error, it seems only prudent to employ more sophisticated forecasting techniques to minimize costs to ratepayers. In any event, if PacifiCorp is setting schedules on 40-45 minute persistence forecasts, the wind integration cost analysis should reflect that.

7. While this IRP is not a ratemaking docket – it is not a contested case, nor does it allow cross examination of evidence – the wind integration study has significant ratemaking implications. PacifiCorp uses the wind integration costs from the IRP for rate setting purposes in the TAM:

> **Q. Has the Company updated its wind integration charges?**
> A. Yes. There are two categories of wind integration charges, one for wind resources located in the Company's control area, and one for the Company's wind resources located in BPA's control area. For the former, the Company continues to use the value from the Company's 2007 Integrated Resource Plan ("IRP") escalated to 2010, which is $1.15 per megawatt hour. For the latter, the charge has

been updated from $0.68 per kW-month to $2.72 per kW-month based on the most recent proposals in the current BPA transmission rate case.[4]

Using these IRP planning estimates for wind integration costs in the TAM – *where rates are set* – will increase rates. As we have shown here, the wind integration study has questionable assumptions that overestimate the cost of wind integration. Because the IRP analysis is then used for ratemaking, overestimation of costs will be applied to all wind in the Company's control area. In the 2010 April TAM filing, PacifiCorp's wind integration costs contributed more than $11 million to net power costs.[5] The new study that the Company is proposing in this IRP will add millions to this amount.

Wind integration costs are different than most other costs that are forecast in the TAM in that they are difficult to verify. Most costs can be verified. Fuel and purchased power costs are contract driven and contract terms are easily verified. While some forecasts such as load and hydro cannot be verified on a forecast basis, we can back-cast them to identify whether our forecasting methodology was reasonable. The wind integration charges here, however, cannot be verified on a forecasted or back-casted basis. This has not yet become a serious problem because wind generation was a small part of a utility's portfolio, so there has been very little rate impact associated with wind integration. Today however, wind is a significant part of the utility's resource portfolio and so the impact of wind integration costs is becoming significant.

It also means that a utility has a financial incentive to assume wind integration costs as high as they reasonably can. If there is a range of costs that can be justified, the utility has an incentive to choose the highest figures in that range, which can potentially yield millions of dollars in additional revenues. Customers, on the other hand, are harmed by overstated wind integration costs. First, customers will see higher rates. Second, customers will see resource portfolios that do not contain an optimal amount of wind resources, potentially leading to additional higher power costs.

Finally, we note that planning and ratemaking are very different. In the planning process we are looking at long-term (20 year) resource development. In ratemaking we are looking at short-term (1 year) resource costs. Now that wind integration is a publicly available service from BPA with a market price, there is no reason to use the wind integration study for ratemaking purposes. We can instead look to the market. One advantage of PacifiCorp's wind integration cost approach is that it is not dependent on running complex and resource intensive computer models. In our view, addressing the deficiencies cited above can be accomplished in a relatively short period of time. It is imperative that the shortcomings of the study be adequately addressed as a condition of the IRP acknowledgement.

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[4] UE 207/PPL(TAM)/100/Duvall/7.

[5] UE 207/Duvall/Non-confidential workpapers/OR GRC-CY2010 NPC Study GOLD _2009 03 24.xls

II. Greenhouse Gas Emissions

PacifiCorp's IRP has taken great strides in its modeling of CO_2 emissions. This is the Company's first IRP since the OPUC issued Order Number 08-339, which prescribes how utilities should consider CO_2 risk in the IRP process. It is clear that PacifiCorp has spent a considerable amount of time considering the implications of this rule and how to accommodate it in their planning process. Overall, PacifiCorp has done a good job of modeling carbon risk and should be commended for this effort. However, we believe there is room for improvement in several areas.

1. PacifiCorp's IRP focuses too much on carbon intensity rather than actual carbon emissions. A graph in the Executive Summary shows the carbon intensity of PacifiCorp's preferred portfolio over the next 20 years.[6] While this chart looks good and illustrates a sharp decline, it is relatively meaningless. PacifiCorp's discussion of greenhouse gas risks makes clear that if " limits are placed on greenhouse gas emissions, it is highly probable that the electric sector will be required to reduce emissions…"[7] Since future carbon regulations of greenhouse will likely require reductions in emissions, rather than reductions in intensity levels, it would be helpful to see a similar chart which shows how the preferred portfolio will perform with regard to total emissions on a year-to-year basis. While some of this information can be extracted from Chapter 8, there is no similar chart that shows how the preferred portfolio performs with regards to total emissions.

2. PacifiCorp's base case assumes a $45/ton cost for carbon, while the Company's analysis shows that carbon emissions will continue to increase with this cost for carbon at this price. The emission intensity chart we mention above shows that the preferred portfolio assumes a $45/ton "tax" on carbon. This is the base case that is used throughout the IRP. However, in its discussion of greenhouse gas risk, the Company makes clear two points. First, as we noted above, the goal of carbon regulation is to reduce emissions. Second, that it will "take a CO_2 price of roughly $50/ton to flatten the growth of emissions."[8] If we accept these two points, then the cost of carbon regulation will have to be greater than we are modeling in order to achieve the results that we want, or we are assuming that the policy of carbon regulation will fail to meet the policy goal of reducing carbon emissions.

3. PacifiCorp tests it various portfolios against a number of carbon costs per ton of emissions ($0, $45, $70, and $100), but except in cases where the mandatory emission caps are hardwired, the costs do not lead to the closure of any pulverized coal power plants.[9] As carbon prices increase, the coal plants operate less and the gas plants operate more, but no coal plants shut down. This is how the Company's model

[6] LC 47, PacifiCorp 2008 IRP, page 9.
[7] LC 47, PacifiCorp 2008 IRP, page 31.
[8] LC 47, PacifiCorp 2008 IRP, page 145.
[9] OPUC Order No. 08-232 on PacifiCorp's 2007 IRP directed: "For the next planning cycle, consider the impacts of forced early retirements of existing coal plants, or retrofits necessary to reduce their CO_2 emissions, under stringent carbon regulation scenarios."

works, but it does not necessarily reflect how carbon regulation will work.

Under a carbon cap-and-trade regime with declining number of carbon credits, the market for those credits will flow toward the most efficient coal plants, leading to the closure of the least efficient plants. Once those plants are closed, they will not be available as seasonal resources, even though additional seasonal resources might be necessary. This scenario is different from PacifiCorp's model, which assumes that all coal plants continue to operate but that they operate less. The costs associated with these two approaches will be different. In addition, while PacifiCorp assumes that the regulation of carbon will be through carbon taxes, there are other approaches that could be put in place through EPA regulation or state regulation. For example, state or national procurement policies might prohibit the extension of the permit life of coal facilities that do not capture carbon. This kind of policy will lead to the shut down of a number of plants. PacifiCorp should refine its modeling so they are be better able to evaluate the effect of the closure of coal facilities.

4. We are also concerned that the Company may not have fully undertaken a trigger point analysis as required by Order No. 08-339. We note that while Table 8.6 provides data on PVRRs relative to varying carbon costs, the IRP does not explicitly address how the substitute portfolio's expected cost and risk performance compares to that of the preferred portfolio.

III. Portfolio Development and Preferred Portfolio Selection

An inherent inconsistency with PacifiCorp's approach to developing portfolios is its reliance on portfolios optimized and fixed over a given future, without respect to the fact that the decisions facing the Action Plan are near-term. It is appropriate to allow the system optimizer model to select the near term part of the portfolio and then fix those decisions, but allow for different choices in later years as necessary. For example, a plan optimized for low market prices would not continue to follow that plan through time if market prices were to rise—planners would make other decisions at later dates in response to a different reality. PacifiCorp effectively freezes all decision making at the present time, without allowing for the fact that future planners would make differing choices in different futures. It is likely that portfolio performance is unduly influenced by parts of the portfolios that are not relevant to the Action plan.

PacifiCorp's choice of preferred portfolio is concerning. The balancing of the quantitative complex scoring scheme with descriptions of similarities, differences, strengths, and weaknesses of the portfolios provides important perspective on the preferred portfolio choice. However, the final choice is between top-scoring portfolios 5 and 8 that differ substantially in their renewable energy content. The concerns expressed previously regarding the overstatement of wind integration costs strongly suggest that a more accurate wind integration cost assumption could well have tilted the preference toward Portfolio 8, or that the system optimizer model would have chosen more renewable resources for Portfolio 5 itself.

IV. Wind Capital Cost Assumption

We recognize the difficulty in undertaking a long analytical process and keeping current on all relevant updates. However, PacifiCorp seems to have updated a number of assumptions in response to the recent economic crisis, but not similarly the capital costs of wind projects.[10] While PacifiCorp explicitly noted the recent reduction in wind turbine costs, it did not incorporate that in its analysis or its discussion of the differences in the top ranking portfolios.

V. Conclusion

PacifiCorp's IRP continues to stand out in the region for its sophisticated analysis. However, we believe there remain some concerning shortcomings. The development of wind integration costs in this IRP diverged significantly from the Company's own earlier analyses, as well as accepted norms for such studies. We urge the Commission to not acknowledge the wind integration study and require the Company to revise its wind integration analysis within three months of the close of this docket. Moreover, the current rate should not be relied upon within the TAM. We also urge that PacifiCorp's CO_2 modeling be further revised to ensure that the preferred portfolio results in actual reductions in carbon emissions, not just carbon intensity.

DATED this 8th day of October, 2009.

RENEWABLE NORTHWEST PROJECT

By: /s/ Ann English Gravatt
Ann English Gravatt

By: /s/ Ken Dragoon
Ken Dragoon

THE CITIZENS' UTILITY BOARD

By: /s/ Bob Jenks
Bob Jenks

[10] LC 47, PacifiCorp 2008 IRP, p. 101.

RNP Exhibit 1

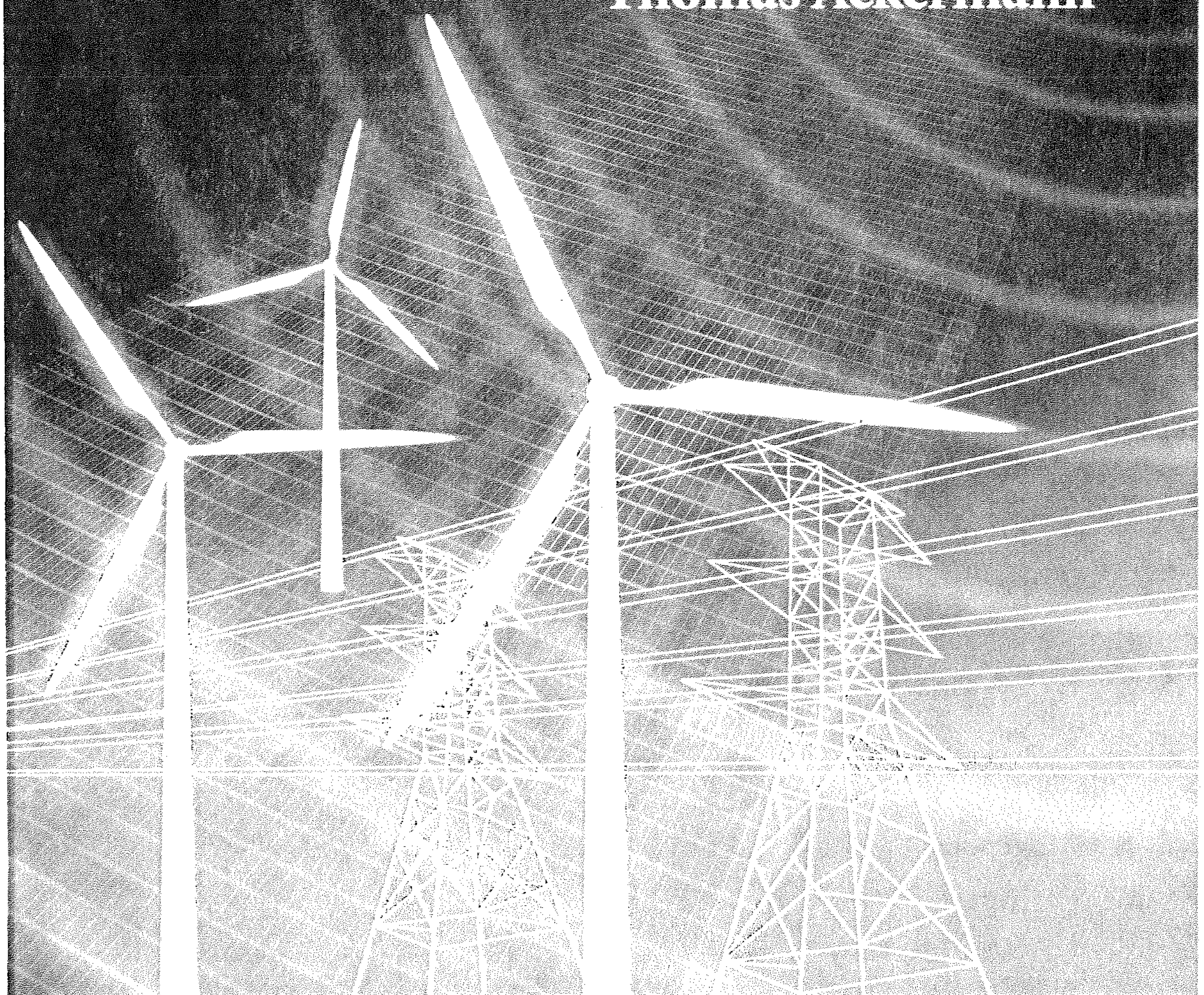
Editor
Ackermann

Wind Power in Power Systems

WILEY

Wind Power in Power Systems

Editor
Thomas Ackermann



WILEY

for frequency control (load following), if the penetration of wind power is large enough to increase the total variations in the system.

Prediction tools for wind power production play an important role in integration. The system operator has to increase the amount of reserves in the system because, in addition to load swings, it has to be prepared to compensate unpredicted variations in production. The accuracy of the wind forecasts can contribute to risk reduction. An accurate forecast allows the system operator to count on wind capacity, thus reducing costs without jeopardising system reliability.

The requirement of extra reserves is quantified by looking at the variations of wind power production, hourly and intrahour, together with load variations and prediction errors. The extra reserve requirement of wind power, and the costs associated with it, can be estimated either by system models or by analytical methods using time series of wind power production together with system variables. Wind power production is not straightforward to model in the existing dispatch models, because of the uncertainty of forecast errors involved on several time scales, for instance (Dragoon and Milligan, 2003). Below, we will briefly describe analytical methods with statistical measures.

The effect of the variations can be statistically estimated using standard deviation. What the system sees is net load (load minus wind power production). If load and wind power production are uncorrelated, the net load variation is a simple root mean square (RMS) combination of the load and wind power variation:

$$(\sigma_{\text{total}})^2 = (\sigma_{\text{load}})^2 + (\sigma_{\text{wind}})^2, \tag{8.1}$$

where $\sigma_{\text{total}}, \sigma_{\text{load}}$ and σ_{wind} are the standard deviations of the load, net load and wind power production time series, respectively.

The larger the area in question and the larger the inherent load fluctuation in the system the larger the amount of wind power that can be incorporated into the system without increasing variations. The reserve requirement can be expressed as three times the standard deviation (3σ covers 99 % of the variations of a Gaussian distribution). The incremental increase from combining load variations with wind variations is 3 times $(\sigma_{\text{total}} - \sigma_{\text{load}})$. More elaborate methods allocating extra reserve requirements for wind power can be used, especially with nonzero correlations and any number of individual loads and/or resources (Hudson, Kirby and Wan, 2001; Kirby and Hirst, 2000).

On the time scale of seconds and minutes (primary control) the estimates for increased reserve requirements have resulted in a very small impact (Ernst, 1999; Smith *et al.*, 2004). This is because of the smoothing effect of very short variations of wind power production; as they are not correlated, they cancel out each another, when the area is large enough.

For the time scale of 15 min to 1 h (secondary control) it should be taken into account that load variations are more predictable than wind power variations. For this, data for load and wind predictions are needed. Instead of using time series of load and wind power variations, the time series of prediction errors one hour ahead are used and standard deviations are calculated from these. The estimates for reserve requirements as a result of use of wind power have resulted in an increasing impact if penetration

RNP Exhibit 2

VTT RESEARCH NOTES 2493

iea wind

Final report,
Phase one 2006-08

IEA Wind Task 25

Hannele Holttinen, Peter Meibom, Antje Orths, Frans van Hulle, Bernhard Lange, Mark O'Malley, Jan Pierik, Bart Ummels, John Olav Tande, Ana Estanqueiro, Manuel Matos, Emilio Gomez, Lennart Söder, Goran Strbac, Anser Shakoor, João Ricardo, J. Charles Smith, Michael Milligan & Erik Ela

Design and operation of power systems with large amounts of wind power

VTT

that any storage should be operated according to the needs of aggregated system balancing. It is not cost effective to provide dedicated back-up for wind power in large power systems where the variability of all loads and generators are effectively reduced by aggregating, in the same way as it is not effective to have dedicated storage for outages in a certain thermal power plant, or having specific plants following the variation of a certain load.

Integration cost of wind power: Many studies address integration costs. Integration cost is the extra cost of the design and operation of the non-wind part of the power system when wind power is integrated. Integration cost can be divided into different components arising from the increase in the operational balancing cost and grid reinforcement cost. It is important to note whether a market cost has been estimated or the results refer to technical costs for the power system. A "market cost" include transfer of money from one actor to another actor, while "technical costs" implies a cost for the whole system. Most studies so far have concentrated on the costs of integrating wind into the power system while also cost-benefit analysis work is emerging. There is also benefit when adding wind power to power systems: it reduces the total operating costs and emissions as wind replaces fossil fuels. Integration costs of wind power need to be compared to something, like the production costs or market value of wind power, or integration cost of other production forms. To enable fair comparison between power systems with differing amounts of wind power, these systems should in principle have same CO_2 emissions, reliability, etc. The value of the capacity credit of wind power can also be stated.

Increase in short term reserve requirements due to wind power: Wind generation may require system operators to carry additional operating reserves. From both the experience and results from studies performed, a significant challenge is the variability of wind power within 1–6 hrs. Frequency control (time scale of seconds) and inertial response are not crucial problems when integrating wind power into large systems at the present time, but can be a challenge for small systems and will become more of a challenge for systems with high penetration in the future. The increase in short term reserve requirement is mostly estimated by statistical methods combining the variability or forecast errors of wind power to that of load and investigating the increase in the largest variations seen by the system. The impact of wind power is mostly seen in the 10 minutes to some hours time scale, and only little in the second to second automatic frequency control time scale. The estimated increase in short term reserve requirements in the studies summarised in this report has a large

RNP Exhibit 3

RNP Data Request 5

Please provide any available analysis showing the reserve requirements for inter- and intra-hour variability and uncertainty in net system demand. (Appendix F, page 271).

Response to RNP Data Request 5

The Company does not have a study currently available showing inter- and intra-hour variability in net system demand.

RNP Data Request 6

Overall reserve requirements are a function of the total system variability and uncertainty of loads and resources. However, one component or another may dominate the need for reserves if the variability and uncertainty of that component is large compared to the other components. Please provide any data or analysis showing that the variability and uncertainty in demand are small compared to that of wind generation. (Appendix F, pp 271-2).

Response to RNP Data Request 6

Please refer to the Company's response to RNP Data Request 5.

RNP Exhibit 4

RNP Data Request 10

Please explain any basis for not netting day-ahead and hour-ahead load and wind imbalances to reduce the overall purchase requirement on some hours. (Appendix F, p. 273, last paragraph).

Response to RNP Data Request 10

Please refer to the Company's response to RNP Data Request 5.

RNP Exhibit 5

RNP Data Request 8

Please explain why the correlations between the added projects and the existing projects are reasonable, or conversely does not significantly effect the overall reserve requirement. (Appendix F, page 273, second to last paragraph).

Response to RNP Data Request 8

For purposes of this study, PacifiCorp assumed that new projects would be sited sufficiently close to existing projects so that correlations already determined for existing projects can be used to help specify correlations between existing and new wind projects based on geographical proximity. The correlations between added projects and existing projects are deemed reasonable given the uncertainty regarding where actual projects will be located several years from now.

RNP Exhibit 6

RNP Data Request 9

Please provide any data or analysis showing that PacifiCorp resolves all load and generation imbalances between expected, day-ahead, and hour-ahead positions through market transactions. (Appendix F, p. 273, last paragraph).

Response to RNP Data Request 9

There is no data or analysis to show that PacifiCorp resolves all imbalances through market transactions. The analysis makes the modeling assumption that the market transactions occur simultaneous with the change in forecast, i.e., forward to day-ahead and day-ahead to hour-ahead, and that all generation is economically dispatched prior to when the change in forecast is known. To address the imbalance, the Company can either transact in the market, or change the dispatch to an uneconomic dispatch. Clearly the choice is to transact in the market. PacifiCorp manages its forward positions to position limits, as guided by the PacifiCorp Energy Risk Management Policy. In addition, PacifiCorp transacts and dispatches resources such that all imbalances are resolved before and during the delivery hour. Reliability standards impose strict limits to the magnitude and duration of operational imbalances.

RNP Exhibit 7

RNP Data Request 3

Please provide PacifiCorp load and wind data for the historical periods over which the wind integration analysis was performed. (Appendix F, page 271, last paragraph).

Response to RNP Data Request 3

Please refer to Confidential Attachment RNP 3 -1 for the 10-minute wind generation data used for estimation of intra-hour reserve costs. Please refer to Confidential Attachment RNP 3 -2 for hourly load data for 2008. Hourly load data for 2009 has not been finalized. Confidential information is provided subject to the terms and conditions of the protective order in this proceeding.

Please refer to Confidential Attachments RNP 3 –(1-2) on the enclosed CD.

CERTIFICATE OF SERVICE

I hereby certify that I served the foregoing **OPENING COMMENTS OF THE RENEWABLE NORTHWEST PROJECT AND THE CITIZENS' UTILITY BOARD** on the following persons on October 8, 2009, by hand-delivering, faxing, e-mailing, or mailing (as indicated below) to each a copy thereof, and if mailed, contained in a sealed envelope, with postage paid, addressed to said attorneys at the last known address of each shown below and deposited in the post office on said day at Portland, Oregon:

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DATED this 8th day of October, 2009.

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