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-BEFORE THE PUBLIC SERVICE COMMISSION OF UTAH-

In the Matter of the Acknowledgment of PacifiCorp's Integrated Resource Plan	))))	**DOCKET NO. 09-2035-01** **COMMENTS**

I. INTRODUCTION

Interwest Energy Alliance ("Interwest") submits the following recommendations for cost-effective carbon-reduced energy resource planning to be incorporated into the 2008 PacifiCorp Integrated Resource Plan (the "Plan").

Interwest is a trade association operating in Colorado, Wyoming, Utah, Arizona, New Mexico and Nevada representing some of the nation's leading companies in the wind and utility-scale solar energy industries and leading regional clean energy advocate groups. Interwest's members will be affected by the Plan. Many are commercial ratepayers with offices located throughout PacifiCorp's services area. Most are independent power producers with information about available energy resources. Interwest members support greater generation diversity, correct incentives, and fair competition to provide the many benefits of developing the most cost-effective, stable rate renewable energy projects to help serve the Company's load. Interwest has previously participated, *inter alia*, in regulatory proceedings throughout the West related to resource planning rules, rules related to renewable energy standards, and in support of wind and solar energy generation and transmission development for renewable energy in utility rate and CPCN cases. Interwest can provide verifiable information related to the alternatives available for resource generation.

II. THE PLAN IGNORES FUNDAMENTAL MODELING RESULTS

PacifiCorp has produced another well-founded, thorough Plan document. The Plan includes a detailed analysis of the relevant information and is relatively easy to understand. However, it fails to incorporate the logical results of PacifiCorp's own modeling techniques as reported in the published Plan documents.

A. The Plan fails to commit to the optimal amount of renewable resources. The least cost-least risk portfolio includes 2400 MW of wind. Instead of adopting this recommended portfolio, however, PacifiCorp chose the second best portfolio, which includes less than 60% of recommended amount. Incorporating 2400 MW of wind is the most cost-effective and efficient portfolio.

1. Stochastic modeling produced the highest overall-rated portfolio.

The Case with the least cost-least risk profile is Case 8. Instead of choosing the second best portfolio, PacifiCorp should rely on the most cost effective and efficient portfolio, as evidenced by Case 8.

Twenty-one portfolios were selected to reflect stochastic costs, stochastic[1] supply reliability risk, and capital cost performance. The results reflected varied CO_2 taxes ranging from \$20/ton to \$70/ton,[2] in part because no single CO_2 reduction compliance approach has

[1] Stochastic means a. "involving or containing a random variable; b. involving probability or chance. Webster's II (1984). A stochastic process (also "random process") deals with indeterminate future probabilities. In this IRP process the initial conditions are known. There are many possibilities the processes might go to but some results are more probable and others less. See Wikipedia.org/wiki/stochastic – process # Definition.
[2] IRP, p.194.

emerged as a consistent front-runner for adoption... IRP p. 143. The $45/ton tax represents a reasonable intermediate value and starting point at which significant changes in resource mix over the long term can be expected to occur. IRP p. 143.

Case 8, Case 5 and Case 9 rank highest based on the average of the CO_2 tax results. IRP pp.194–195; Table 8.6. Case 8, Case 5 and Case 9 rank the highest in line with the stochastic mean PVRR values. IRP p. 197; See Table 8.3.

Case 8 ranks lowest in cost exposure for carbon dioxide tax outcomes. See Table 8.11. In other words, maximum projected loss is lowest because there is zero cost exposure if carbon is taxed at $56/ton with no probability weights applied.

Case 8 results in lower CO_2 emissions than Case 9. See Table 8.25, IRP p. 224.

Case 8 and Case 5 outrank Case 9 for normalized preference scores across the expected CO_2 tax levels.

2. Present Value Revenue Requirements Also Validate Higher Levels of Stable-Priced Renewable Energy Resources. A measure of the risk-adjusted PVRR (Present Value Revenue Requirements) by portfolio indicates Case 8 prevails.[3] See Table 8.0 (insert); IRP p. 197. The PVRR measure captures the total resource cost for each portfolio, including externality costs in the form of CO_2 cost adders. Total resource cost includes all the costs to the

[3] The stochastic mean PVRR for each portfolio is the average of the portfolio's net variable operating costs for 100 iterations of the PaR model in stochastic mode, combined with the real levelized capital costs for new resources determined by the System Optimizer model. The PVRR is reported in 2009 dollars as of January 1, 2009. IRP p. 170.

utility and to customers for the variable portion of total system operations and the capital requirements for new supply and Class 1 demand side resources as evaluated in the IRP. See IRP p. 170.

Portfolio mixes represented in Case 2, Case 5, Case 8 and Case 9 performed best overall. The preference scores vary across CO_2 tax levels.[4] IRP p. 229. Case 2 performed best with tax levels below $40, while Case 8 portfolio scores best at levels $50 and above. Both Case 5 and Case 8 are "equally strong contenders" to be the 2008 IRP preferred portfolio. The main difference between the two portfolios is that Case 8 includes 1,150 and more wind in the first ten years (600 MW more overall) and lacks a gas peaking resource in 2016. Case 5 also includes more east-side front office (market purchase) transactions in the first 10 years than Case 8.

The assumed CO_2 cost is the key determinant for overall portfolio performance: Case 8 out performs Case 5 with CO_2 taxes at $45 and above, but the reverse is true with CO_2 taxes below $56.

Both Case 5 and Case 8 rely heavier on market purchases than other portfolios although Case 8 ranks better than Case 5. IRP p. 231.

PacifiCorp believes that firm market purchases benefit the preferred portfolio by increasing planning flexibility and resource diversity at a time of considerable regulatory uncertainty. IRP p. 231. Fixed-rate wind PPAs can fulfill this need.

[4] PacifiCorp dropped Cases 2 and 9; See p.230

> Regarding fuel source diversity, the Case 8 portfolio has a greater proportion of renewable generation – and generation reduction in the case of Class 2 DSM – than for Case 5, particularly in the near term. On the other hand, Case 5 has a greater share of gas generation, and for the first 10 years, more reliance on generation from market purchases. By 2028, the generation mix for the two portfolios look similar. The significant difference is that Case 5 includes a clean coal resource in 2025, which Case 8 depends on much earlier wind investment to meet CO2 and RPS compliance requirements.

IRP p. 232. The Public Service Commission of Utah required PacifiCorp to "examine the cost of consequences of the superior portfolios with respect to uncertainty by subjecting them to evaluation under the initial set of relatively broad input assumptions." IRP p. 232. Case 8 and Case 5 portfolios were nearly equal with respect to both PVRR average and standard deviation. IRP p. 232.

The greatest variable cost is natural gas fuel prices. Case 5 has a greater share of gas generation (and significantly less wind generation) than Case 8, and in the first 10 years, more reliance on generation from market purchases. IRP p.232. This subjects ratepayers to the whirlwind of natural gas prices. Natural gas prices will undoubtedly increase from current levels, and have been quite volatile in recent years. This reliance is therefore questionable as compared to investment in wind which includes minimal fuel costs and stable prices over the long term.

The portfolio for Case 8 has both the lowest PVRR and the smallest PVRR variability across the risk scenarios. IRP p. 233.

Case 8 outranks case 5 on the basis of having the lowest rank sum (16) p. 233. Case **5 (?)** falls to 3rd place in this ranking. Id.

Case 5 performs best in low natural gas price assumptions and low CO_2 tax scenarios, but worst in high natural gas price assumptions and high CO_2 tax assumptions. IRP p. 234. Case 8 performed best under the medium/high gas price and medium/ high CO2 tax scenarios, but performed worst in low gas/low CO2 scenarios. There is an important public policy reason to prefer a case that assumes high natural gas prices: to protect consumers. Assume that any natural gas price forecast will likely be wrong. This is a fair assumption, since, over decades, it has been the case that most natural gas price projections have turned out to be incorrect, either too high or too low. This is because natural gas is an international commodity that is subject to a large number of variables that affect price: oil prices, speculation, cyclical market conditions, hurricanes, and national policies, just to mention a few. Natural gas price projections, therefore, are likely to be too high or too low, but it matters a lot to consumers. If the projection is too low, and utilities acquire gas equipment and pass gas costs on to consumers through rates, then consumers are hurt. They pay the price of the higher than anticipated gas cost. However, if natural gas price projections are too high, consumers will pay more than ideal amounts for more efficient gas burning equipment, insulation, and renewable energy (particularly wind, which tends to offset gas costs first), but these investments will have the effect of erecting a hedge against the next gas price spike. So if projections are going to be wrong, the commission should lean toward being wrong and too high, rather than wrong and too low, to protect consumers.

The scenario risk assessment yielded findings similar to the stochastic mean cost analysis regarding the top-performing portfolio, Case 8. IRP p. 234.[5]

[5] PacifiCorp did not find the scenario risk assessment to add value to the discussion, so they indicate "the stochastic risk analysis is sufficient for exploring portfolio cost outcome given a range of input assumptions reflecting uncertainty and risk. IRP p. 235.

Case 8 is the highest-performing portfolio and has more renewables, including nearly twice as much wind. Therefore, PacifiCorp should have preferred it over Case 5 due to external requirements to increase renewables to 20% in several jurisdictions in the near future, as well as Utah's own more broadly-stated requirement that renewables be incorporated if cost-effective. PacifiCorp's own modeling proves that Case 8 should be required for the IRP to be acknowledged by the Utah IRP.

PacifiCorp indicates it prefers Case 5, although the reasoning is weak. Then when analyzing based on the input about their waiver of a gas purchase, they chose another portfolio which also included just over half of the wind that was recommended in Case 8. Therefore, Interwest asks this PSC not to acknowledge the 2008 IRP, unless acknowledgment is conditioned on PacifiCorp relying on the most cost effective portfolio. Rather, Interwest urges PacifiCorp to find ways to incorporate the greater proportions of wind resources into its systems, by its own development and by working closely with independent power produces to acquire a variety of renewable resources in a cost-effective manner.

Since CO_2 taxes are new to US markets they are difficult to predict, but we have significant measurable patterns indicating that natural gas prices will very likely rise and fall unpredictably over time, and in the recent past has included intolerable spikes that have challenged consumers' ability to pay.[6] Case 5 prolongs that risk for both large and small consumers.

[6] For history of natural gas prices to commercial consumers, see, e.g. Energy Information Administration, *Monthly U.S. Price of Natural Gas Sold to Commercial Consumers*,:http://tonto.eia.doe.gov/dnav/ng/hist/n3020us3m.htm

To the extent PacifiCorp invests in other generation facilities, the funds will have been "sunk" into those assets rather than in renewable wind energy, and resources will not be available later to invest in cost-effective wind facilities (or fixed rate or indexed-rate PPAs for wind energy). This may mean consumers will pay higher costs than they would have in the event that carbon control measures are imposed. The "best" (highest capacity) wind projects, nearest to transmission, that result from competitive bidding should be developed immediately.

Case 8 provides the foregoing benefits and savings to consumers in a cost-effective manner. Case 8 ranks lowest of all of the modeled portfolios in carbon tax exposure for lowest risk-adjusted PVRR, lowest in overall CO_2 emissions, and the lowest "rank sum". Therefore the Public Service Commission should refuse to acknowledge the IRP unless conditioned on PacifiCorp committing to pursue Case 8 resources, since it fails to incorporate the logical results of PacifiCorp's own modeling. Interwest urges greater acquisition of wind resources in the early years of this resource plan.

3. **PacifiCorp's wind integration costs used for modeling purposes are excessive.** PacifiCorp acknowledges that it must use wind integration analysis based on the unique elements of its generation system. However, this information was not available for it to use for the purpose of the 2008 IRP, so it must rely on other utilities for estimate integration costs instead.

> Due to a number of project schedules, this wind study was not completed in time to be incorporated into the 2008 IRP portfolio modeling. ...a value of $11.75/MWh -- based on Portland General Electric Company's latest wind integration study--was used for IRP capacity expansion optimization modeling purposes....

See IRP, p. 162. PacifiCorp acknowledges the differences between its own system and Pacific Power's. Appendix F "Wind Integration Cost Update", reflects some analysis in Table F.7 indicating the Total Expected $/Expected MWh ranges from $9.96/MWh to $11.85/MWh. In itself, this is a 16% variance. These overstated costs exaggerate the revenue requirements projected to incorporate wind into the portfolio.[7] There are more current studies published by Xcel Energy which indicate that the $11.85 figure is at least twice what it should be. In 2006, Xcel Energy found its 10% wind integration cost to be $3.51/MWh for its 2007 load, and its 15% wind integration cost to be $4.77/MWh.[8] While there also may be significant differences between Xcel's and PacifiCorp's systems, theses costs should be analyzed carefully and substantiated by publicly available, peer-reviewed studies conducted in transparent processes to obtain the benefit of state-of-the-art research. Wind integration costs are likely to be found to be much lower that the $11.85 figure used for modeling in this IRP, which handicaps wind energy in ways which are not well-founded or consistent with Utah public policy. The commission must insist that PacifiCorp pursue "least cost" integration strategies so that new renewable projects can be added to the system over time without being taxed by outdated operational, scheduling, and forecasting methods.

[7] PacifiCorp has "significantly advanced" its forecasting process, retained a firm to prepare forecasting for day-to-day balancing activities, and "will consider the concept of the peer group review for evaluation of its ongoing refinement of wind integration cost estimation methods as part of the IRP public participation process". See Appendix F, p. 278. These are all important advancements which must be adopted into the IRP planning process to allow ratepayers the benefit of the most cost-effective integration cost modeling and techniques.

[8] "Wind Integration Study for Public Service Company of Colorado", prepared by EnerNex Corporation for Xcel Energy, May 22, 2006; http://www.xcelenergy.com/Company/About_Energy_and_Rates/CO%20Least-cost%20Resource%20Plan/Pages/Regulatory_Documents.aspx as updated by the "Addendum, Detailed of 20% Wind Penetration", EnerNex, December 31, 2008; http://www.xcelenergy.com/SiteCollectionDocuments/docs/CRPWindIntegrationStudy.pdf

III. THE PLAN VIOLATES UTAH PUBLIC POLICY

A. The Plan fails to comply with Utah statutes related to energy resource planning. SB 202, codified at Utah Code §54-17-502 and §54-17-601 et seq. requires as follows:

> (1)(a) To the extent that it is cost effective to do so, beginning in 2025 the annual retail electric sales in this state of each electrical corporation shall consist of qualifying electricity or renewable energy certificates in an amount equal to at least 20% of adjusted retail electric sales.
>
> (2)(a) Cost-effectiveness under Subsection (1) for other than a cooperative association is determined in comparison to other viable resource options using the criteria provided by Subsection 54-17-201(2)(c)(ii).
>
> (i) complies with this chapter and rules made in accordance with Title 63G, Chapter 3, Utah Administrative Rulemaking Act; and (ii) is in the public interest taking into consideration: (A) whether it will most likely result in the acquisition, production, and delivery of electricity at the lowest reasonable cost to the retail customers of an affected electrical utility located in this state; (B) long-term and short-term impacts;
>
> (C) risk; (D) reliability; (E) financial impacts on the affected electrical utility; and (F) other factors determined by the commission to be relevant.

The Plan does not advance PacifiCorp's compliance with the requirement that it incorporate sufficient renewables to progress towards 20% by 2025. At its current rate of acquisition, PacifiCorp will not achieve this goal.

Table 8.22 (IRP p.222) compares the relative percentages of renewable resource acquisition to acquisition of other types of fuels. Case 5 provides for 36% of

renewable/DSM by 2013; Case 8 provides 58%. In 2020, Case 5 advances the cause to 57%, whereas Case 8 reaches 67%. Table 8.24 indicates, similarly, that by 2028 the resource shares under Case 5 will include 50% renewables/DSM, whereas Case 8 brings PacifiCorp closer to compliance at 61% overall. See IRP, p. 223. Therefore, Case 8 (with greater wind investment through 2018 brings PacifiCorp at least 10% closer to compliance by 2020. This planning fails to comply with Utah's public policy on its face.

1. The Plan Virtually Ignores Stable-rate Customer-sited Solar Resources.

Customer-sited solar resources have been given little attention in this IRP. Nearby states are competing to be the solar capital of the U.S. including Colorado, New Mexico, and Arizona. Each has developed a program suitable for its energy resource situation.

a. Benefits of On-site Solar Electric Resources

Customer-sited solar electric resources provide benefits to the customer through electric bill savings, price stability and reduced carbon footprint. These resources also provide benefits to the citizens of Utah through reduced emissions and reduced requirements for transmission facilities by locating energy resources at or near the load being served. Not widely recognized however, is that customer-sited solar resources provide documented benefits to the host utility. For example, Arizona Public Service (APS) in January 2009 completed a study entitled *Distributed Renewable Energy Operating Impacts and Valuation Study*. About one year ago, APS engaged a group of consultants, led by R.W. Beck, to determine the potential value of distributed solar energy technologies for its electrical system, and to understand the likely

operating impacts. The analysis found the benefits to the APS system range from about 8¢ to about 14¢ per kWh?.[9]

b. Jobs Created by Distributed Solar Electric Resources

Much has been written and debated about the jobs that result from development of solar electric resources. A recent study prepared by Navigant Consulting for the Solar Energy Research and Education Foundation (a non-profit 501(c)3 affiliated with the Solar Energy Industries Association) was released September 15, 2008,[10] and summarized the jobs resulting from PV resource development as approximately 15 to 30 jobs per MW installed. The Navigant Study anticipates improved solar labor productivity between 2005 and 2015 and shows that each additional installed megawatt of solar has the potential to add many job-years of employment. The study also shows that the jobs associated with manufacturing and assembly of PV system components are essentially the same across market segments. The differences in local job creation between the market segments are due primarily to the system integration, installation, and maintenance elements, and total approximately 4 jobs per MW.

The bottom line: a stable, consistent and viable distributed solar installation market allows solar companies to plan for the longer term by using more full-time design, engineering, procurement, and construction staff, and making longer term commitments to suppliers. Inconsistent on-again off-again solar markets require the local industry to be rebuilt multiple times, including redevelopment of supplier pipelines, greater use of temporary help, and additional and repetitive training for competent technicians. Inconsistency and instability assure

[9] Source: www.aps.com/solar
[10] Source: http://www.seia.org/galleries/pdf/Navigant%20Consulting%20Report%209.15.08.pdf

that distributed solar electric resources will remain an expensive resource option far longer than necessary.

IV. ENERGY-FIRST PLANNING CONCEPTS

A. The Plan fails to incorporate transmission planning designed to acquire cost-effective renewable energy sources over the long term[11].

Planning and development of new transmission lines is a complex process that can last 10 years from project inception to commercial operation. Transmission planning must proceed in a coordinated, transparent and public manner under FERC Order 890 regulations. In order to bridge the timing gap between the speed at which renewable energy projects can be developed, and the much slower tempo for providing transmission to serve these projects, we look to public policy developed in state statute and rules, including SB 202, which states a clear mandate to acquire more renewable resources. Interwest urges PacifiCorp to acknowledge that renewables are cost-effective, to incorporate more wind energy in its early planning years, and to pick up the pace at which transmission is being planned and built.

Transmission planning should include statewide coordinated planning so PacifiCorp's planned transmission additions are not duplicative of other utilities' plans or undersized to meet long term needs. PacifiCorp does not address the timing gap between new consumer-beneficial renewable energy projects and the development of transmission lines to deliver the energy to

[11] "Renewables-First Transmission" will cite and incorporate more updated version when received. http://www.interwest.org/documents/documents/2007-06-06_olsen.pdf.

serve the loads served. They do not require maximum use of efficiency or other "non-wires" alternatives, such as those identified by BPA http://www.transmission.bpa.gov/planproj/nonwires.cfm.... Transmission should be provided in concert with considerations for environmental quality and with impacts on wildlife and habitat in mind[12] and better real-time data and control techniques to minimize the need for new lines.

PacifiCorp does not sufficiently address the need to plan for transmission for the long term. Large-scale renewable energy projects and transmission built to conduct their energy to consumers are cost-effective energy for consumers over the long run. They provide economies of scall and allow coal generation to adopt new carbon and cost-saving technologies. They comply with public policy, including the Department of Energy's Wind Vision, Western Governor's, and Utah's S.B. 202. Large renewable projects fulfill the purposes of these stated policies:

energy security

reduction in carbon to reduce effects and costs of climate change

achieving RPS and IRP mandates

rate stability, diversification

allows accelerated carbon capture-sequestration development

Large scale renewable energy generation projects of 2,000 MW capacity or more ("Mega-Projects") appear able to economically justify major transmission infrastructure, even with no initial participation by coal generation. This approach supports development of major

[12] *www.westernresourceadvocates.org/energy/**smartlines**.php*

new transmission capacity, and facilitates diversification of utility supply portfolios with renewables.[13]

Developers, manufacturers, utilities and investors may own subproject shares of an overall Mega Project consortium.

> A few very large projects can add as much wind generation capacity as hundreds of traditional 100 MW projects, and can be developed and built much more quickly. Compared to traditional wind plants, Mega Projects are likely to provide significant economies of scale not only in development and permitting, but also in financing, component sourcing, construction, power marketing and operation. These economies may help drive down the cost of energy from large-scale renewables development.
>
> Large-scale renewables developments are best organized as integrated generation-transmission projects. This enables transmission to be optimized to access renewable resource areas, and generators to subscribe for the full capacity of the transmission before it is built.

Olsen, p. 7

> With their relatively low capacity factors, most wind and solar projects cannot by themselves load transmission lines to economic levels. Economic loadings are generally in excess of 60% of transmission line capacity, depending on the size, length, terrain and electrical complexity involved. This has led to the conventional wisdom that variable-output resources must have on-demand generation as transmission partners, or be coupled with energy storage projects, to achieve economic levels of line utilization.

Olsen, p. 8.

> Over-building the installed generating capacity of variable-output projects offers an alternative. In this approach, a wind project, for example, would install 10%-30% excess generative capacity. Building 3,600 MW of wind generation to supply a 3,000 MW -rated double-circuit 500 kV line (20% over-build) could

[13] "Renewables First Generation / Transmission Projects", Dave Olsen, Center for Energy Efficiency and Renewable Technologies, Windpower 2007 Conference, 2007.

increase line loading to the 60% range, depending on the capacity factor of the wind project.

Olsen, p. 9.

Mega Projects with high capacity factors can enable this development in a cost-effective manner. There are several examples already under development. See generally, Olsen, pp. 11-15. The Frontier Line Economic Analysis Subcommittee compiled generation cost and performance data and, led by Pacific Gas & Electric, developed a spreadsheet model to evaluate the costs and benefits of different combinations of generation resources in various states on different transmission routings. Transmission carrying only wind power emerged as one of the best-performing alternatives. Olsen, p.11. Olsen notes that it appears that renewables-first transmission development as he advocates complies with OATT regulations, although there was no definitive FERC ruling that transmission built initially to carry only wind or other renewables generation complies with the open access provisions of Order 890. 0 There are several wind-only transmission lines in operation now:

Therefore, Interwest advocates for renewables Mega Projects and generation-driven transmission development. Renewables-first transmission can help meet climate change initiatives, RPS requirements, and at a minimum, allow PacifiCorp to meet the public policy established by Utah's statutes.

PacifiCorp has imposed annual constraints on its purchase of wind, which are not substantiated by the modeling. They have "manually" (or arbitrarily) imposed these restraints

upon the modeling process, based on assumptions about their ability to incorporate wind into their system.

> See IRP fn. 38, p. 148:
>
> This wind acquisition schedule reflects an assessment of RPS requirements, capital budget impacts, current and prospective commercial opportunities, transmission constraints and expansion considerations (i.e., the Energy Gateway Transmission Project), operations and system integration issues, locational diversity, state procurement rules, and the MEHC renewables acquisition commitment.

See generally, Chapter 7, Modeling and Portfolio Evaluation Approach, Modeling Wind Resources:

To reflect realistic system resource addition limits tied to transmission availability and other factors such as resource market availability and procurement constraints, System Optimizer was constrained to select up to 500 MW per year of wind prior to 2014, and 750 MW per year in 2014 and thereafter. See IRP p. 162.

> ...additional constraints are required to emulate a long-term procurement program that ideally accounts for rate stability/financial impacts, anticipated demand for construction and equipment resources, flexibility to respond to changing market and regulatory conditions, construction management requirements, and location-specific considerations not factored into the IRP models. The Company believes that given the current sophistication of capacity expansion optimization models, development of a suitable wind acquisition schedule that takes these various factors into account is best handled outside of the model. Consequently, PacifiCorp manually developed a wind acquisition schedule based on the aggregate wind amount from the 5B_CCCT_Wet portfolio, and then ran System Optimizer with this fixed wind schedule and the 5B_CCCT_Wet input assumptions. The resulting portfolio, presented in the next section, constitutes PacifiCorp's preferred portfolio.

Chapter 8, Modeling and Portfolio Selection Results, IRP p. 240.

The strategy behind this acquisition schedule is to distribute wind quantities across all years of the business planning period (2009-2018) and through 2021, keeping annual amounts at 200 MW or less. The benefits to customer and Company stated therein weigh much more heavily in favor of the Company than the customer, considering wind's fixed costs and its ability to reduce CO_2 carbon costs. Interwest supports the concept of regular wind procurement in order to support build and support stable markets, which reduces costs overall.[14] Therefore the balancing of wind acquisition through the years the IRP is in effect makes good economic sense, but the amounts of wind should be increased throughout, with some increase now to reduce risks of the PTC terminating after 2012.

The worldwide market for wind power has grown at a 37% annual rate from 2000 to 2007.[15] This growth is driven by concerns about increasing fossil fuel prices, energy security, and the environmental effects of traditional power generation.[16]

Diversifying PacifiCorp's resource mix is good business. The risk premium for potential carbon liability is growing, in step with the world wide movement toward carbon regulation and financial market demand for carbon disclosure.[17]

[14] This stable market-concept is further supported by PacifiCorp reinstating the 2008 RFP immediately, as anticipated by PacifiCorp, bidders, regulators and rate payers as a result of the 2007 IRP.
[15] Olsen, p.3.
[16] Id. Utah's SB 230 requires that PacifiCorp incorporate renewable energy where cost-effective.
[17] Olsen, p.5. Renewable energy generation requires virtually no water consumption after installation.

Respectfully submitted this 17th day of June, 2009, by

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On Behalf of Interwest Energy Alliance

CERTIFICATE OF SERVICE

I hereby certify that on this 17th day of June, 2009, a true and correct copy of the foregoing **Comments** was e-mailed to mlivingston@utah.gov and that the original and five (5) copies were delivered by Federal Express overnight delivery service to:

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and that a true and correct copy of the foregoing **Comments** were placed in the United States mail addressed to:

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