BEFORE THE IDAHO PUBLIC UTILITIES COMMISSION

IN THE MATTER OF THE COMMISSION'S INVESTIGATION INTO DISAGGREGATION AND AN APPROPRIATE PUBLISHED AVOIDED COST RATE ELIGIBILITY CAP STRUCTURE FOR PURPA QUALIFYING FACILITIES	)	CASE NO. GNR-E-11-01

DIRECT TESTIMONY OF CLINT KALICH

AVISTA CORPORATION

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I. INTRODUCTION AND TESTIMONY OVERVIEW

Q. Please state your name, the name of your employer, and your business address.

A. My name is Clint Kalich. I am employed by Avista Corporation ("Avista") at 1411 East Mission Avenue, Spokane, Washington.

Q. In what capacity are you employed?

A. I am the Manager of Resource Planning & Power Supply Analyses, in the Energy Resources Department of Avista.

Q. Please state your educational background and professional experience.

A. I graduated from Central Washington University in 1991 with a Bachelor of Science Degree in Business Economics. Shortly after graduation, I accepted an analyst position with Economic and Engineering Services, Inc. (now EES Consulting, Inc.), a northwest management-consulting firm located in Bellevue, Washington. While employed by EES, I worked primarily for municipalities, public utility districts, and cooperatives in the area of electric utility management. My specific areas of focus were economic analyses of new resource development, rate case proceedings involving the Bonneville Power Administration, integrated (least-cost) resource planning, and demand-side management program development.

In late 1995, I left Economic and Engineering Services, Inc. to join Tacoma Power in Tacoma, Washington. I provided key analytical and policy support in the areas of resource development, procurement, and optimization, hydroelectric operations and re-licensing, unbundled power supply rate-making, contract negotiations, and system operations. I helped develop, and ultimately managed, Tacoma Power's industrial market access program serving one-quarter of the company's retail load.

In mid-2000, I joined Avista and accepted my current position assisting in resource analysis, dispatch modeling, resource procurement, integrated resource planning, and rate case proceedings. Much of my career has involved resource dispatch modeling of the nature described in this testimony. I have represented Avista in substantially all PURPA-related cases in which Avista has participated since 2000, including providing expert witness testimony.

Q. What is the purpose of your testimony?

A. In Order No. 32176 issued in Case No. GNR-E-10-04, the Commission temporarily set the eligibility cap for published avoided cost rates for wind and solar qualifying facilities at 100 kW, while the Commission investigates the implications of disaggregated QF projects. To that end, the Commission initiated this proceeding to investigate and determine in a finite timeframe requirements by which wind and solar QFs can obtain a published avoided cost rate without allowing large QFs to obtain a rate that is not an accurate reflection of a utility's avoided cost for such projects. Specifically, the Commission on page 11 of Order No. 32176 solicited in this proceeding "information and investigation of a published avoided cost rate eligibility cap structure that: (l) allows small wind and solar QFs to avail themselves of published rates for projects producing 10 aMW or less; and (2) prevents large QFs from disaggregating in order to obtain a published avoided cost rate that exceeds a utility's avoided cost."

In my testimony, I explain that it will be difficult or impossible to prevent disaggregation of large QF projects so long as the published avoided cost rate is available to QFs as large as 10 aMW. However, assuming the Commission reestablishes the 10 aMW eligibility cap for published avoided cost rates, I will explain why it is important that the Commission ensure that the published avoided cost rate reflects the utilities' actual avoided costs to remove the economic incentive that currently exists for developers to disaggregate. Simply stated, the economic incentive created by the current published avoided cost rates, which exceed the utilities' actual avoided costs, is the fundamental driver of Idaho's PURPA issues—including disaggregation.

In addition to addressing the published avoided cost rate, I will explain that, if the Commission reestablishes the 10 aMW eligibility cap for published avoided cost rates, it is also important that the Commission adopt additional requirements designed to prevent disaggregation. In my testimony, I outline some requirements the Commission might adopt to reduce the likelihood of disaggregation, but at the same time explain that even if such requirements are adopted, it is unlikely that disaggregation will be prevented over the longer term. I will explain why enforcement and monitoring of such requirements will likely create substantial administrative burden due to the need to monitor and enforce such requirements.

Finally, I will explain why making the 100 kW eligibility cap for published avoided cost rates permanent is a more effective and efficient way to prevent disaggregation while fully meeting the intent of PURPA.

Q. Are you sponsoring any exhibits in your testimony?

A. Yes. I am sponsoring two exhibits with my testimony. The first, Exhibit No. 101, details the variability of a solar facility relative to a wind facility, and explains that solar variability should be of great concern to the Commission. The second, Exhibit 102, details the PURPA requests presently before Avista.

II. INITIAL OBSERVATIONS

Q. Before beginning, do you have any overriding observations to share with the Commission?

A. Yes. There are three fundamental drivers that have brought us together in this proceeding: (1) the utility's avoided cost to build or acquire wind or solar variable energy renewable resources, and their associated benefits to the system, is fundamentally different from that of a combined cycle combustion turbine, (2) published avoided cost rates for variable energy renewable resources exceed Avista's actual avoided costs for similar resources, and (3) an eligibility cap for published avoided cost rates that extends those rates to large sophisticated developers.

I believe that it is in the interest of all participants, including the developers, the Commission, and the utilities to finally address the underlying long-standing PURPA issues so that a more permanent resolution of these issues can be accomplished.

Q. Please explain what you mean when you say that the utility's avoided cost to build or acquire wind or solar variable energy renewable resources, and the associated system benefit that these resources provide, is fundamentally different from that of a combined cycle combustion turbine.

A. The variable energy generation resources being constructed by QF developers (e.g., wind and solar) benefit from a number of tax and other benefits that CCCT projects do not receive. The most significant of these include federal production and investment tax credits and accelerated depreciation that can buy down the cost of a new plant by 50% or more. In addition, these generation projects receive a significant revenue stream from the value of the renewable energy credits (RECs) they create based on the quantity of generation produced effectively lowering the net busbar price of these types of projects relative to a CCCT. CCCT plants do not significantly benefit from these federal tax incentives and they do not generate RECs.

On the other side of the equation, variable energy generation resources do not provide the same level of generation value that CCCT projects do. Variable energy generation is a net consumer of system capacity whereas a CCCT plant is a net contributor of system capacity. CCCT plant operations can be modified by the utility on demand in response to changing load or other system conditions whereas variable energy generation resources only contribute to the extent that the motive force (wind in the case of a wind plant, or sunlight in the case of a solar plant) is present. These resources do not provide generation at the times of extreme system peak. Therefore, on a planning basis, the on-peak capacity contribution of these resources is zero or near zero.

The bottom line is that the surrogate avoided cost CCCT has a much higher power production value to the system from an operations perspective than variable energy generation resources, while variable energy generation resources benefit from significant tax savings that are not available to CCCT resources. Therefore, paying for variable energy generation at prices based on a CCCT does not approximate true utility avoided costs for variable generation resources.

Q. Please explain what you mean when you say that published avoided cost rates that exceed the utilities' actual avoided costs is a fundamental driver of Idaho's PURPA issues—including disaggregation.

A. The high rate paid to QF developers is a fundamental driver of the PURPA issues that have been raised in Idaho. Idaho's published avoided cost rates exceed that of neighboring states and actual avoided costs. The chart below details Idaho and surrounding state PURPA rates.

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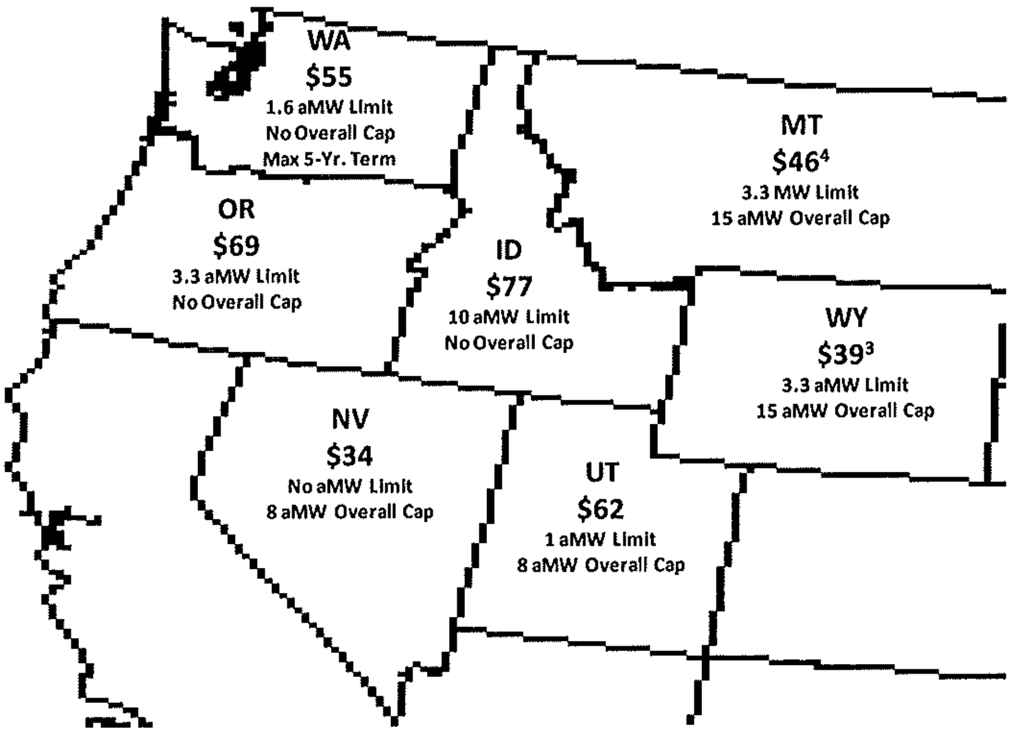
Chart 1
Northwest State Published PURPA Rates and Eligibility for Wind[1]



[1] Capacity-based limits and caps are converted to aMW using a 33% capacity factor for comparison to Idaho
[2] NV based on COB Index, shown as 2010 average
[3] WY assigns RECs to utility; their price is reduced by $15 per MWh for consistency with other states in this graphic that do not obligate developers to provide their RECs as a precondition of a PURPA sale.
[4] MT requires wind to provide ancillary and wind integration, reduced rate by IPUC $6.50/MWh rate

In addition to the prices, Chart 1 identifies the largest individual project size assuming a wind resource is offered by a QF developer, and also the maximum amount of PURPA wind generation that would be allowed to be sold within the state under the published rate structure before the state commission would revisit the tariff. In other words, some states put a limit on the amount of total generation (i.e., a summation of all individual QF projects) that can be contracted for under published rates.

That Avista has two PURPA QF wind developers in Oregon interested in selling power into Idaho is a strong indication that Idaho's published avoided cost rates are too high. These QF developers, with projects in a neighboring state, have demonstrated that they are willing to wheel power, at their expense, to utilities in the State of Idaho in order to take advantage of Idaho's published avoided cost rates. This fact illustrates Avista's belief that the fundamental issue before us is the price paid to QF developers—that is, whether the published avoided cost rate accurately reflects the utility's actual avoided cost for such projects. Therefore, if the Commission reestablishes a 10 aMW eligibility cap for published avoided cost rates, this mismatch between the published avoided cost rate and the utilities' actual avoided cost for a similar resource is the threshold issue that must be addressed to solve Idaho's PURPA issues—including disaggregation.

Q. What is the third fundamental driver of PURPA proceedings in Idaho?

A. The Federal Energy Regulatory Commission ("FERC") mandated a published rate for projects 100 kW or smaller. The primary justification for a published rate is to simplify the contracting process for truly small developers. By establishing a 10 aMW eligibility cap, this Commission has (prior to the recent temporary reduction of that cap) in recent times has chosen to define a small developer to be 10 aMW–much larger than the FERC rule requires. A 10 aMW wind project has a price tag of $60 million or more. A 100 kW project has a price tag closer to $300,000. Use of a 10 aMW threshold enables developers of a wind project 200 times larger than a 100 kW project to become eligible for published rates. The level of capital investment should be considered when establishing a maximum size for PURPA published rate eligibility.

Q. Do you have any other preliminary observations you would like to share with the Commission?

A. Yes. During this proceeding, NIPPC brought to the attention of Avista the Commission's 1995 Order 26576 discussing the IRP Methodology, among other items. In reading through that order, the Commission made a statement that could not better represent the position of Avista today. Specifically, the Commission stated:

> "...it would be nothing more than an artificial shelter to the QF industry to provide those [QF] projects with contract terms not otherwise available in the free market. We can find no justification for insisting that Idaho's investor-owned utilities and their ratepayers assume such an obligation simply to foster one particular segment of an increasingly competitive industry."

By returning the published rate eligibility for wind and solar variable energy qualifying resources back to 10 aMW, the Commission will indeed be providing an artificial shelter to a significant portion of the QF industry that would otherwise not be available to those resource types in the competitive market. As I explained above, Avista's present published avoided cost rates are in fact substantially higher than our actual avoided costs. Avista's customers are required to bear the burden of the published avoided cost rate. I submit that a simple solution exists to protect Avista customers from greatly over-paying for PURPA: permanently cap published rate eligibility at 100 kW.

III. PREVENTING DISAGGREGATION WITH A 10 AMW PUBLISHED RATE ELIGIBILITY CAP WILL BE DIFFICULT AT BEST

Q. The Commission has indicated its desire to remove the temporary 100 kW limit on wind and solar eligibility for published avoided cost rates, and return the eligibility cap to 10 aMW. Can the Commission adopt a PURPA eligibility cap structure that both allows wind and solar QFs as large as 10 aMW to avail themselves to published rates and also prevent large QFs from disaggregating in order to obtain the published avoided cost rate?

A. No. It is very unlikely that the Commission will be able to adopt a PURPA eligibility cap structure that both allows wind and solar QFs as large as 10 aMW to avail themselves to published rates and also prevent disaggregation. As discussed earlier, the Commission will, at minimum, both need to address the published avoided cost rate methodology applicable to wind and solar variable energy resources and, second, adopt a strict set of requirements in order to effectively prevent disaggregation. Such requirements may include, for example, requirements with regard to project ownership, the sharing of equipment and infrastructure, and a geographical separation rule. Most importantly, the foundational step should be to put in place an avoided cost structure representative of the characteristics, costs and benefits unique to wind and solar variable energy resources that customers otherwise would receive if the utility had built or purchased from the marketplace a resource of similar type.

Q. Why is changing the published rate paid for QF resources essential to preventing disaggregation?

A. As explained earlier, the published avoided cost rates in Idaho are currently based on a natural gas fired combined cycle combustion turbine ("CCCT") surrogate avoided cost resource ("SAR"). As a result, the current published avoided cost rates do not reflect, and are significantly higher than the actual avoided costs of other resource types—especially wind resources. As discussed more fully below, the published avoided cost rate provides a strong economic incentive for QF wind developers to disaggregate their projects to avail themselves of published avoided cost rates.

Absent disaggregation, QF developers with projects larger than the eligibility cap would have to sell the output of their project in the competitive wholesale marketplace or under rates calculated using the IRP Methodology. For a wind QF, for example, as is shown later in my testimony, the IRP Methodology would not generate the magnitude of profits available to a QF developer under current published rates. It follows that the current published avoided cost rate provides a substantial incentive for developers to find a way to develop their projects such that they can take advantage of the published avoided cost rates. The developers' strong objection to using the IRP Methodology to set the avoided cost rate for their projects highlights this point.

Unless the economic incentive is removed by establishing published avoided cost rates that more closely reflect actual avoided cost, developers will find ways to circumvent the Commission's intent to provide published avoided cost rates only for truly small QF projects. Accordingly, any solution to the disaggregation problem in Idaho, other than a permanent reduction in the eligibility cap, must start with addressing the mismatch between published avoided cost rates and the utilities' actual avoided costs.

Q. Please further explain your statement that the current published avoided cost rates do not reflect, and are significantly higher than, the actual avoided cost associated with other types of resources—especially wind resources.

A. To best answer this question, it is important to understand the recent history of the wind business and development in Idaho, including the costs and incentives available to wind developers.

Q. Please describe the relevant history of wind development in Idaho, especially with regard to PURPA development.

A. Idaho has witnessed a significant build-out of PURPA wind projects in the past two years. Prior to 2009, Idaho had 75 MW of PURPA wind nameplate capacity in the state and delivered to the electric systems of the three jurisdictional utilities.[1] At the end of 2010 the total rose to 460 MW. The following Chart 2 details development in Idaho.

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[1] This total focuses on projects in Idaho. It does not include the 9 MW Exergy Horseshoe Bend wind farm located in Montana that sells to Idaho Power under PURPA.

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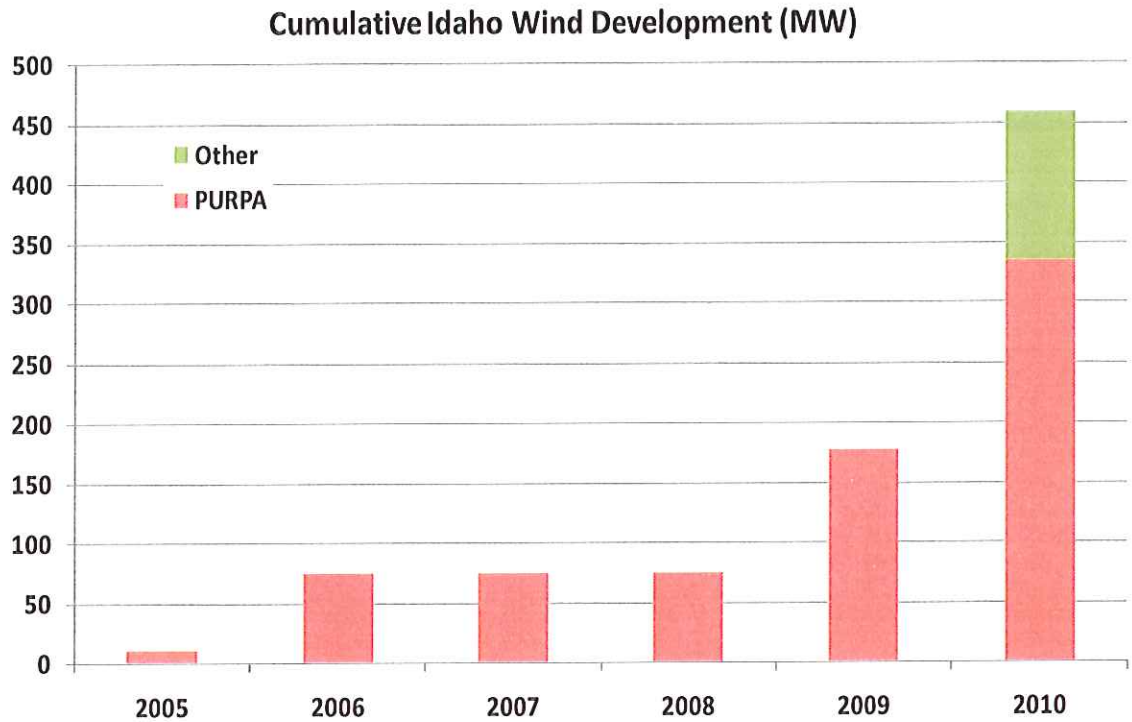
Chart 2



Wind development in Idaho prior to 2009 consisted of just two projects: the 10.5 MW Fossil Gulch project in 2005 and the 64.5 MW Wolverine Creek project in 2006. These wind projects were sold under PURPA to Idaho Power and PacifiCorp, respectively. In 2009, Idaho went from two to eight wind projects. The additional six 2009 wind facilities were completed by two developers, Exergy and one additional developer (who operated under three different limited liability companies). Another ten projects were added in 2010 by three developers– Exergy built eight projects, John Deere and Ridgeline built one each–bringing the total number of developed wind projects in the state to 18 at the end of 2010. All but one of the wind projects are being sold to Idaho utilities under PURPA.

PURPA contracts presently account for approximately three-quarters (¾) of total Idaho wind farm nameplate capacity.

Q. **What has been the principle driver for wind development in Idaho?**

A. As with any development, the driver is fundamentally economics. A rational developer will not complete a project where its net costs exceed expected revenue. But once project costs are exceeded by revenues, development occurs. Where developers judge that they can expect revenues to substantially exceed net costs, one can expect the market to swing dramatically to deliver to that sector of the market. The wind PURPA market in the state of Idaho has experienced exactly this type of substantial market shift.

Q. Please explain the conditions that existed in 2005 and 2006 when the first 75 MW of Idaho wind came online.

A. The conditions in 2005 and 2006 were quite different from today. Even under those conditions, the economics were good enough to convince two developers to complete Idaho projects. Both wind projects were sold to Idaho utilities under published avoided cost rates that were much lower than they are today. State and federal tax incentives were generous in the 2005-06 period, but arguably the then-available production tax credit ("PTC") offered by the federal government was of less value relative to the current federal investment tax credit ("ITC").

Wind project costs are heavily front-weighted. More than 70% of the lifecycle cost of a project is determined by the cost of the wind farm installation.[2] In 2004

[2] Based on "Avoided Cost Wind 1 1.xlsm" model received via email from Idaho Commission Staff on December 7, 2010. Results are based on using Avista's capital cost structure contained in the model, a plant cost of $1,500 per kilowatt, use of the federal ITC, a net capacity factor of 31.3% and excluding the

and 2005, the likely timeframe in which turbine purchases were made for the 2005-06 wind projects, wind turbine prices averaged $939 according to a 2010 Lawrence Berkley National Laboratory study.[3] Overall installation costs averaged $384 per kilowatt, for a total installed cost of $1,323 per kilowatt. These costs equate to a 20-year levelized production cost of $56.98 per MWh.[4] The $56.98 per MWh wind cost compares favorably to the then-available Idaho published avoided cost rate of roughly $70 per MWh. Given that the cost of a wind farm completed in 2005 or 2006 was substantially below the available published avoided cost rate, developers in a position to construct wind farms were able to proceed at substantial profit.

Q. **Why did development pause after 2006?**

A. There were two reasons. First, in August 2005 the Commission issued Order No. 29839. This order reduced the eligibility of wind projects for published rates to 100 kW. This cap was in effect until Order No. 30500 was issued on February 20, 2008 after the utilities and the QF developers agreed to a wind integration charge to account for the system impacts of wind's varying generation profile. Second, the economics of wind were no longer as favorable to wind development. Wind project costs (i.e., turbines and construction) increased substantially, yet the published avoided cost rate remained the same as in 2005. In 2006, again using the Lawrence Berkley National Laboratory study, average wind construction costs

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wind integration and transmission components. All other assumptions remained the same as the model from IPUC Staff.

[3] 2009 Wind Technologies Market Report, Wiser R. and M. Bolinger. LBNL-3716E. August 2010, see http://eetd.lbl.gov/ea/ems/re-pubs.html

[4] See footnote 1, except use $1,323 per kW for the wind project cost..

were $1,602 per kW. This cost equated to a figure of $68.19 per MWh, a figure essentially equivalent to the published avoided cost rate available at the time.[5] As a result, the economics were not as favorable to the development of wind projects during this time period. Wind turbine prices continued to increase after 2006, whereas the Idaho published avoided cost rate did not change substantially until 2008.

The following Chart 3 describes graphically how Idaho PURPA rates have compared over time to wind development costs. The comparison shows true avoided costs for utilities assuming the RECs generated by the utility-built project are sold into the marketplace at $15 per MWh. By assuming a sale of the RECs, the utility cost estimate is shown on an apples-to-apples basis to the PURPA rate where RECs are not awarded to the utility.

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[5] See footnote 1, except assume $1,602 per kW for the wind project cost.

Chart 3
Idaho PURPA Rate Comparison

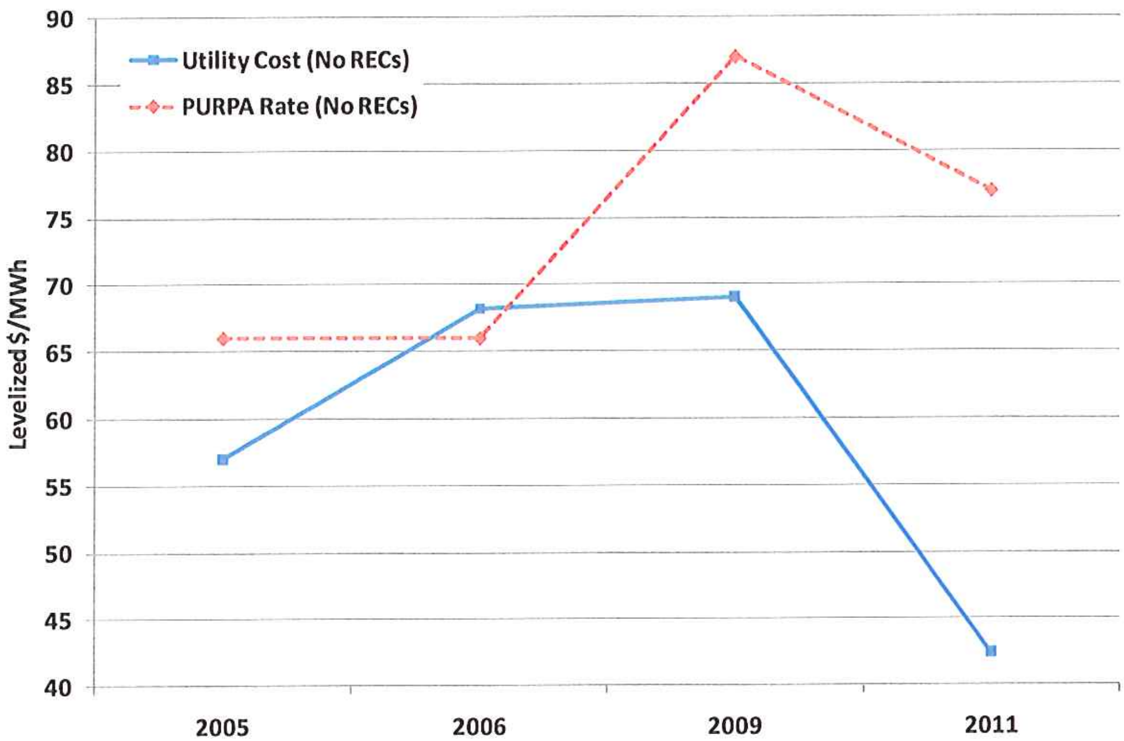

Chart 3 shows historical utility avoided cost estimates for wind power (net of RECS), and the PURPA rate for comparison. For present conditions, a comparison of estimated development costs and the additional profits are displayed. The development cost of $57.41 compares favorably to the approximately $92 per MWh revenue that a QF developer would likely receive for their project. The profits total nearly $35 per MWh. Profits are achieved by a $19.59 premium between the published avoided cost rate and the cost to construct the resource. In addition, RECs bring another approximately $15 per MWh of profit.

Q. Do economics then explain the recent increase in Idaho QF wind development?

A. Yes. In 2008, the stars began to align to make wind development feasible in Idaho again. There are at least five changes that have benefitted development. First there were significant increases in the Idaho published avoided cost rate. Second was the emergence of a renewable energy credit ("REC") market in the Western states. Third was the federal government's decision to allow wind developers to opt for a 30% ITC as a cash grant in lieu of a PTC. Fourth, the cost of wind project equipment began falling precipitously after early 2010. Finally, in February 2008 the Commission increased the eligibility cap for published rates to 10 aMW, which among other things made it easier for large projects to disaggregate.[6]

Q. Please explain how changes to Idaho published avoided cost rates have benefitted wind developers.

A. Idaho published avoided cost rates remained relatively stable between late 2004 and early 2009 at near $70 per MWh. For a year, from early 2009 through early 2010, published avoided cost rates rose by more than $15 per MWh, from approximately $70 to approximately $87 per MWh.[7] This $17 per MWh increase was worth $1.5 million per year, or $30 million over 20 years, to a 10 aMW QF wind developer entering into a contract during this time.

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[6] Prior to this time, wind projects were capped at 100 kW nameplate. As commercial wind turbine sizes exceeded the 100 kW cap substantially, it was impossible to disaggregate at 100 kW.

[7] $87 figure is adjusted downward from $93 to reflect a 7% Avista wind integration discount. The earlier $70 PURPA rate was not subject to this discount.

In early 2010, the Commission lowered the published avoided cost rates by approximately $10 per MWh to account for a new gas price forecast; however, the downward revision still left rates $7 per MWh higher than what they were prior to 2009. At the lower rates, a 10 aMW wind QF project still would garner increased revenues of approximately $600,000 per year, or $12.3 million over 20 years, relative to rates in place between 2004 and early 2009.

Q. Please explain how the renewable energy credit market has benefitted wind developers.

A. In 2005, Montana mandated a renewable portfolio standard. In 2006 Washington State did the same. Oregon followed in 2007. California in 2010 increased their renewable energy target to 33% by 2020. A tradable market for RECs emerged in the later part of the last decade, providing new renewable energy resources a significant new revenue stream. Avista's experience shows that these RECs have a value oscillating around $15 per MWh in the northwest. At that value, RECs can provide a 10 aMW project with $1.3 million per year in annual revenues, or $26.3 million over a 20-year period. This was a game changer by itself.

Q. Please explain how the federal ITC has benefitted wind developers.

A. Relative to the PTC, the ITC benefits wind projects by as much as $10 per MWh, or approximately $875,000 per year, or $17.5 million in total for a 10 aMW project.[8] The new ITC, and its provision to be rebated rather than in the form of a tax credit, make financing wind projects much more profitable to developers.

[8] *See* footnote 1, except assume $2,122 per kW for wind project costs in 2009. Comparison of model using ITC versus PTC.

Q. **Please explain how changes to wind project costs have benefitted wind developers.**

A. At their peak, wind turbines sold as high as $1,700 per kW.[9] Adding to that the $595 per kW estimate for construction and plant balance of facilities costs from the 2010 Lawrence Berkley National Laboratory study, the total cost of a wind installation was $2,295 per kW in 2009. Running this cost through the IPUC Staff's wind model, the 20-year levelized cost of a wind project with these costs is $84.06 per MWh.[10] Projects today can be installed for approximately $1,500 per kW, or $57.41 per kWh.[11] This 32% reduction in project cost equates to a developer savings of nearly $27 per MWh. This equals $2.3 million per year on a 10 aMW wind project, <u>or nearly $50 million over 20 years</u>.

Q. **Please summarize the developer benefits created by the changes you have just described.**

A. In total, a single 10 aMW wind QF project would benefit by more than $100 million over 20 years from these changes relative to developing a project in the 2006-08 time period. The components of these benefits are explained below in Table 1.[12]

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[9] Avista received bids at this level from leading turbine vendors in late 2009 as part of its 2009 renewables RFP.

[10] *See* footnote 1, except assume $2,295 per kW for the wind project cost.

[11] *See* footnote 1, except assume $1,000 per kW for turbines, $500 per kW for construction and balance of plant.

[12] One of the PURPA issues in Idaho is whether the RECs associated to a QF go to the developer or to the utility. Table 1 assumes, without conceding, that the developer receives the RECs associated with its QF.

Table 1

Change	Per Unit $/MWh	Annual $millions	20-Year $millions
Renewable Energy Credits	15	1.3	26.3
Federal Investment Tax Credit	10	0.9	17.5
2010 vs. 2008 PURPA Rate	7	0.6	12.3
Wind Plant Cost Reduction	27	2.4	47.3
Total	**59**	**5.2**	**103.4**

Table 1 illustrates clearly why wind development in Idaho has accelerated in recent years. High published avoided cost rates have contributed significantly to the acceleration.

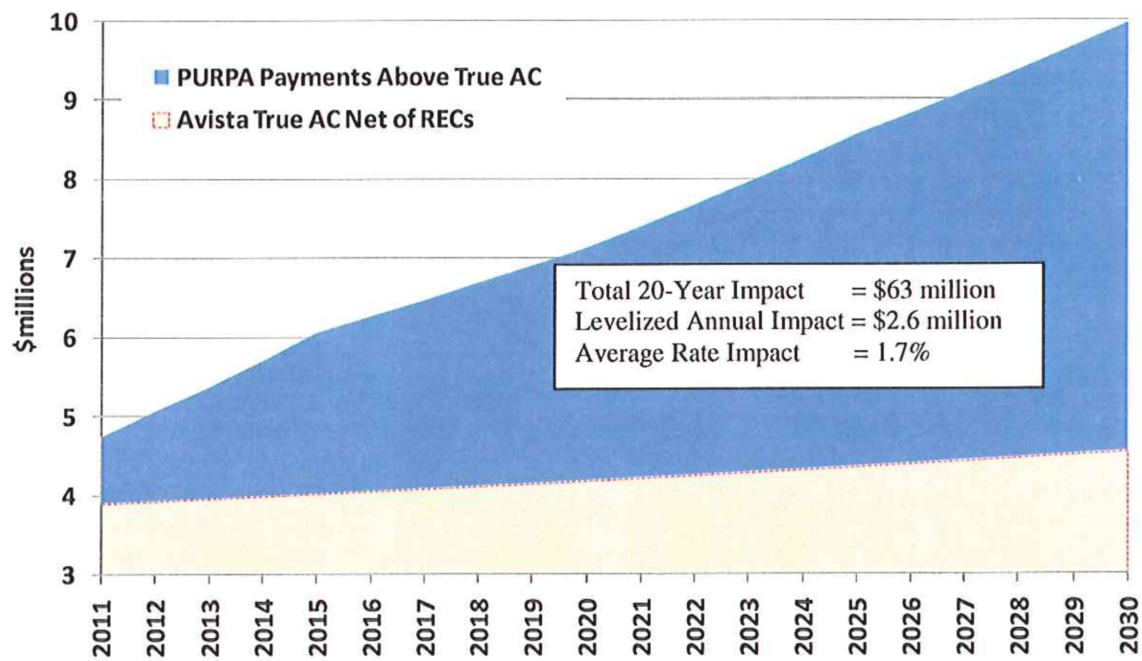
Q. What would be the result of returning wind and solar project published rate eligibility to 10 aMW.

A. As illustrated above, and later in this testimony, wind developers in Idaho could continue to reap exorbitant profits at the expense of utility customers who would simply see their bills raise more than they would were these projects purchased at actual utility avoided costs. And, as we have seen in the past two years, many large projects would continue to be built. Idaho customers could end up footing the bill for hundreds of megawatts of additional wind development at prices well above the value the resources bring.

Q. Were the Commission successful in its efforts to limit eligibility to published rates to only those projects that are truly a 10 aMW size (i.e., not disaggregated to obtain more than one contract to cover a project of a size that greatly exceeds 10 aMW), would customers be protected?

A. No. A 10 aMW wind project is being overpaid by approximately $63 million over 20 years. Each project would raise Avista electricity rates in Idaho by approximately 1.7% relative to what rates would be if actual avoided costs were instead paid. The following Chart 4 illustrates the annual impact of a 10 aMW PURPA project in Idaho relative to a utility-built option in today's market conditions.

Chart 4
Impacts of Single 10 aMW PURPA Wind Project
(upper shaded area represents cumulative impact of PURPA payments in excess of avoided costs)



Q. **What changes to the methodology for setting published avoided cost rates are required?**

A. The present SAR methodology for setting published avoided cost rates should be modified to ensure comparability with resources the utilities would build and own or otherwise acquire. This can be accomplished by either using the IRP

Methodology for projects exceeding a reasonable threshold (i.e., 100 kW), or by modifying the existing SAR methodology to account for changing gas prices and a capacity discount for variable generation, or by creating a wind-based SAR for developing published avoided cost rates applicable for resources with characteristics more similar to wind (e.g., variable with environmental attributes).

Q. How does the IRP Methodology ensure a fair avoided cost?

A. The IRP Methodology calculates the value of a PURPA development just as it would for an equivalent utility-build option. The IRP Methodology determines the applicable value of the QF resource's energy, on-peak capacity contribution, RECs, and risk reductions. To the extent Avista is long during the period of proposed PURPA deliveries, the PURPA developer is compensated only for the market value of the project, including RECs. However, once Avista becomes deficient (approximately 2020), the value of the PURPA resource goes up substantially because it is offsetting the construction of a new generation asset.

Q. Will the IRP Methodology provide PURPA developers with a rate substantially similar to the current published avoided cost rate?

A. The answer to this question depends on the characteristics of the particular project. However, given Avista's present surplus position, the level of the current wholesale electricity marketplace and the changes in the wind marketplace in the past few years described earlier in my testimony, the IRP Methodology will likely provide a payment that is below the current published rate. However, this lower payment is appropriate because the rate calculated using the IRP Methodology will reflect the actual avoided cost of Avista, whereas the higher published rate does not.

Q. Is it fair to apply the IRP Methodology to PURPA developers with projects over 100 kW?

A. Yes. As noted earlier it is worth emphasizing that FERC only requires published avoided cost rates for QFs that are 100 kW or smaller. The real question is whether utility customers should be required to overpay for a PURPA resource. To be sure, projects above 100 kW will not be underpaid—they will receive an avoided cost rate that reflects the utility's actual avoided cost as required by PURPA. The problem is that wind resources obtaining the current published rate are being overpaid. So the predicament we are in is that large wind developers see a lucrative published rate that does not reflect the value of the resource and provides them with a revenue stream that substantially exceeds their costs.

Q. Given the explanation above, how then should PURPA developers of projects exceeding 100 kW be compensated?

A. The rate should reflect the actual value of the resource to Avista and its customers. As has been stated before, the best means to determine actual avoided costs in the current environment is to calculate the value of the PURPA development using the IRP Methodology.

Q. Has PURPA compromised Avista's resource acquisition efforts?

A. Yes. Avista recently issued a request for proposal (its 2011 renewables RFP). Avista received no Idaho project in its 2011 renewables RFP. With today's "fair" market for wind projects near $60 per MWh, including RECs, it does not make economic sense for an Idaho wind project to sell its output, including RECs, to Avista through an RFP. Instead it can develop its project as a QF (or disaggregate the project into multiple QFs) and sell to Avista (or another Idaho utility) at the published rate of approximately $77 per MWh <u>and</u> potentially retain the RECs.[13] If PURPA brings a developer $92 per MWh ($77 MW published rate plus $15 per REC) and a competitive bidding process only brings $60, the 20-year additional profit to the PURPA developer is huge–around $56 million. The rate impact of a single contract of this size is approximately 1.2% higher rates. Of course, the losers in this arrangement are Avista's customers who would bear the burden of that $47 million inflated bill.

Q. Would limiting published rate eligibility to 100 kW prevent customers from paying too much for PURPA variable energy from wind and solar facilities?

A. No. However, the financial impact to customers would be substantially lower. A 100 kW project generates approximately 0.3% (275 MWh/yr) of the energy of a 10aMW (87,600 MWh/yr) project. Therefore, even though the payment on a per-MWh basis is still much too high, the total overpayment that customers bear is modest. Instead of an overpayment of $56 million over 20 years, the additional cost is limited to 0.3% of that, or $175 thousand. The rate impact of a single contract fall from 1.2% at 10 aMW to 0.0036%.

Q. Are there any other factors that should be considered when setting published avoided cost rates?

[13] $82 less a 7% wind integration charge

A. Yes. The published avoided cost rate should consider the utility's need for the resource.

Q. Why should the Commission consider whether or not the purchasing utility has a need for the resource when it establishes the published avoided cost rate?

A. There are at least two reasons why utility need should be considered when setting the published avoided cost rate. First, the value of a project is vastly different when a utility is resource deficit relative to when it is resource long or resource balanced. If the Commission ignores the utility's load and resource balance, utility customers pay too much for a wind project under published avoided cost rates. Second, as evidenced by the magnitude of wind interconnections on Idaho Power's system, a consideration of utility need is essential to ensure reliable grid operation. Although the specific level of generation that might impact a utility's electrical system operation, such that operations and/or operating costs are material impacted, is not known at this time, this information will become available over time as the industry further studies the impacts of variable generation resources. To the extent that grid operation is materially impacted, the published avoided rate should reflect this concern and be set in a manner that avoids encouraging more variable energy generation than the electrical system can reliably accept.

Q. Please explain how avoided costs are affected by the utility's need, or lack thereof, for new resources.

A. A utility's need for resources is an essential consideration in the avoided cost calculation. Where a utility is resource deficient (i.e., loads exceed resource capabilities) it is reasonable to assume that avoided costs are equivalent to the construction and operation costs of a new generation asset, at least for a portion of the deficiency that the utility intends to meet with new generation assets. Avoided costs therefore can equal the cost of the utility's intended resource purchases. Where the published avoided cost rate is based on the intended resource purchase, it can approximate utility avoided costs.

However, where a utility does not require new resources, any QF resource purchase will necessarily be resold into the wholesale marketplace. The construction and operation of a new resource—which is the present basis for the published rate—are almost always more expensive than power bought and sold in the wholesale marketplace. Therefore where a utility is surplus any power purchased under published rates will be sold at a financial loss. The avoided cost in this circumstance clearly is not that of a new generation resource. Avoided cost rates, published or otherwise, should not be based on the cost of a new generation resource when the utility does not have a need for the power.

Q. How should utility need be considered in avoided cost rates?

A. When a utility is short and requires resources, the avoided cost rate should reflect the least-cost new generation resource that would satisfy the utility's need and fit appropriately within the utility's resource stack. In contrast, during the period when a utility is even or long and has resources adequate or in excess of its needs, the avoided cost rate should be capped at the expected revenue the utility will received when the output of the QF is sold in the wholesale marketplace.

Q. Why would the wholesale market price be a cap and not a floor on the avoided cost rate when a utility is long?

A. It is possible, and in fact likely, where a utility is even or long resources relative to loads, that the additional energy generated by the QF resource will reduce the value of the utility's surplus power sales created by existing portfolio resources. Where this is the case, the avoided cost rate must be reduced to account for this impact on the utility's surplus sale revenues.

Q. How should the Commission account for the impact of a deficit or surplus utility position in setting the published avoided cost rate?

A. When a utility is surplus, the avoided cost rate should be capped at the wholesale market price. For large QF resources (i.e., those above 100 kW), the IRP Methodology should be employed to assist in quantifying any negative impacts on existing utility surplus sales.

Q. Should published rates be subject to a consideration of utility need?

A. Yes. Published rates should default to market prices where the utility is not in a deficit position.

Q. How should the Commission determine if a utility is in a surplus or deficit position?

A. In earlier proceedings, interveners expressed concern that utility load-resource positions were not stable or predictable. To remove this concern, Avista proposes that the determination of need should be based on the most recent utility IRP, adjusted only where a major resource acquisition has been completed or is imminent or a major change in load has occurred or is known.

Q. Is there precedent for considering utility need in setting published avoided cost rates in Idaho?

A. Yes. Prior to Commission Order No. 29124 issued in GNR-E-02-01, the utility's load and resource balance was central to the rate paid for QF power.

Q. Why did the Commission eliminate the consideration of utility need?

A. In Order No. 29124, the Commission expressed concerns with, among other things, determining actual load and resource positions.

Q. You explain above that the Commission in Order No. 29124 eliminated the consideration of utility need when determining published avoided cost rates. What is different today than in 2002?

A. There are two major differences. First, since that order, utility integrated resource planning processes have become more sophisticated and are regularly (i.e., biannually) updated. There are now robust processes including opportunities for public input. Each utility IRP describes its load and resource balances for 20 years forward. The position of the utility is no longer a matter of debate or a mystery.

Second, the maximum size of resources eligible for published rates has increased tremendously since the elimination of a utility need consideration. At the time of Order 29124, published rate eligibility was limited to projects with a maximum generating capacity of 1 MW. A 1 MW nameplate wind project generates approximately 0.3 aMW. This compares to today's 10 aMW eligibility—which is approximately a 30 MW nameplate wind project. A wind project's output eligible for published avoided cost rates has therefore increased by 30-fold.

IV. IN ADDITION TO CHANGES TO THE SAR METHODOLOGY, THE COMMISSION WILL NEED TO ADOPT ADDITIONAL REQUIREMENTS TO PREVENT DISAGGREGATION.

Q. You stated earlier that, in addition to changes in the methodology for determining avoided cost rates, a strict set of requirements with regard to ownership, sharing of equipment and infrastructure, and geographical separation rules will be required to prevent disaggregation. Please explain.

A. Although aligning published rates with utility avoided cost rates will be helpful in removing the economic incentive to disaggregate to take advantage of published avoided cost rates, it will be very difficult or impossible to completely remove that incentive. Therefore, if the published avoided cost rates are available to projects as large as 10 aMW, additional requirements will need to be adopted to make it more difficult for developers to disaggregate in order to circumvent the intent of the published avoided cost rate. Requirements might include ownership limitations such as contractual representations and warranties affirming that developers of projects greater than 100 kW do not share any equipment (e.g., interconnection facilities, maintenance buildings, collector systems) with any other QF and that the developer does not have a direct or indirect interest in any other QF within 10 or more miles.

Q. Why will aligning published rates with utility avoided costs by itself not prevent disaggregation?

A. Published rates are updated infrequently, and data sources used to develop the SAR are based on historical pricing information that could be inaccurate. It is therefore possible, and in fact is what we are seeing today, for the published rate to significantly exceed current resource development and operation costs. Even if the recommendations presented in this testimony were adopted, the lag could enable large projects to arbitrage where market conditions have changed and the published rates have not.

Q. Does Avista believe that the adoption of such requirements will prevent disaggregation?

A. No. Such requirements may help in the short term. However, so long as published avoided cost rates are available to projects as large as 10 aMW, developers will likely find a way to disaggregate their projects so that they can take advantage of the published avoided cost rate.

Q. Why do you believe that developers will try to find a way around any requirements adopted by the Commission that are designed to prevent disaggregation?

A. Developers have already demonstrated that they will go to great lengths to take advantage of the published avoided cost rates. The Commission need look no further than the efficiency in which developers have already abused the 10 aMW eligibility cap. As Commission Staff acknowledged in GNR-E-10-04:

> The development of large wind projects in Idaho over the past six years has blurred the distinction between large and small QFs. Wind projects are unique from other generation technologies because they normally consist of multiple turbines, each with its own generator, often scattered over large areas. Because of this characteristic, wind projects capable of

generating more than 10 aMW per month can be subdivided into multiple legal entities and reconfigured into smaller projects in order to qualify for the historically higher published avoided cost rates. It has become quite common for large wind projects to be structured as multiple, separate QFs, each 10 aMW in size, but collectively 60, 80 or 120 MW in size. In fact, nearly all new wind contracts submitted for Commission approval in recent years are collections of two or more adjacent 10 aMW projects, each with common ownership and developers.[14]

Q. Are there other examples of QFs circumventing state PURPA requirements to take advantage of published avoided cost rates?

A. Yes. Avista understands that there is a recent example in Oregon where a developer was able to effectively disaggregate a 65 MW wind project. In this case, published avoided cost rates were available under Oregon rules only for projects that were 10 MW (nameplate rating) or less and that were separated by at least five miles from other QF projects owned by the same developer. Notwithstanding those limitations, a single developer was able to devise a scheme to break down its 65 MW wind project, covering an 8-10 mile footprint, into multiple QFs so that each qualified for published rates.

To achieve this result, ownership was broken up between the developer, the various landowners, and the entity providing project financing. Five miles separated each "owner" and the large project was developed as one, enabling economies of scale across the whole development, construction, and operations cycle. Absent disaggregation, this developer almost certainly could have constructed at most two 10 MW PURPA projects on its development, or 20 MW.

[14] Comments of Commission Staff in IPUC Case No. GNR-E-10-04, at p. 4.

Instead, it managed to work within the rules and develop more than three times the limit.

This example is particularly instructive in that it demonstrates the ability of a developer to disaggregate to take advantage of published avoided cost rates even where an eligibility cap is set at a level substantially less than the 10 aMW level that the Commission is considering here (10 MW nameplate wind is approximately one-third the size of a 10 aMW wind project). It also demonstrates how a developer can circumvent rules put in place (i.e., a five-mile separation and ownership) to prevent it. Certainly the State of Oregon, in its attempt to limit eligibility, expected its adopted rules to successfully prevent disaggregation. Yet it was not successful. The Commission should expect no greater success where the economics of disaggregation remain.

Q. Are there other issues associated with a rate structure that includes an eligibility cap of 10 aMW?

A. Yes. As the example discussed above illustrates, developers can come up with very imaginative ways to disaggregate and still comply with even very strict requirements designed to prevent such disaggregation. It is impossible to foresee the various ways that developers may come up with to circumvent the intent of the eligibility cap by disaggregating their projects. Additional requirements regarding ownership, sharing of equipment and interconnection facilities, and project separation rules might help, but they will be very difficult for utilities, and ultimately this Commission, to monitor and enforce. Avista is concerned that such additional requirements will lead to additional litigation that will require substantial time and resources in order to enforce the intent of the published avoided cost rate eligibility cap. More importantly, to the extent that developers are able to require utilities to pay rates above the utilities' actual avoided costs for large QF projects, the utilities' customers will shoulder the burden of those costs through higher retail rates.

V. PERMANENTLY SETTING THE ELIGIBILITY CAP FOR PUBLISHED AVOIDED COST RATES AT 100 KW IS THE MOST EFFICIENT WAY TO SOLVE THE DISAGGREGATION PROBLEM.

Q. Does Avista have a proposal that will achieve the Commission's goals of solving the disaggregation problem and ensuring that published avoided cost rates are still available for truly small QFs?

A. Yes. Permanently setting the eligibility cap for avoided cost rates at 100 kW will satisfy the goals of solving the disaggregation problem, protecting utility customers from paying significantly more for QF power than they otherwise might, and the goal of ensuring that published avoided cost rates are available for truly small QFs.

Q. The Commission has indicated that it is interested in an eligibility cap structure that "allows small wind and solar QFs to avail themselves of published rates for projects producing 10 aMW or less. . . ."[15] Does Avista's proposal meet that criterion?

A. Avista's proposal does not provide an eligibility cap structure that allows QFs as large as 10 aMW to avail themselves of published avoided cost rates. However, Avista's proposal is consistent with what the Commission has indicated as the

[15] Order 32176 at 11.

primary reason for published rates–to ensure that truly small QFs can avail themselves of published avoided cost rates.

Q. Please explain why Avista believes its proposal is consistent with the Commission's intent.

A. The Commission clearly indicated in Order No. 32176 that it is interested in ensuring that small wind and solar QFs are able to avail themselves to published avoided cost rates. Avista agrees that published avoided cost rates are generally appropriate for truly small QFs. For such projects, published rates are justified because "small QFs are less likely to be large, well-financed organizations, capable of sophisticated contract negotiations. By making published rates available for small projects, rate negotiations can be eliminated and contracting costs can be minimized."[16] 10 aMW wind or solar projects are <u>not</u> small QFs. Published rates are required by FERC for projects of up to 100 kW in size. This Commission has expanded eligibility to include projects up to 10 aMW. Indeed, it might well be efficient from a Commission and societal perspective to allow developers with modest means access to a published rate. However, any developer that is able to develop a QF as large as 10 aMW cannot fairly be characterized as small, of modest means, or unsophisticated.

First, the ability to secure land control for hundreds, if not thousands, of acres of land indicates a level of competency beyond that which one could fairly characterize as small and unsophisticated. Second, the negotiation of turbine supply and balance of plant contracts that run into the tens if not hundreds of

[16] *See* Comments of Commission Staff in IPUC Case No. GNR-E-10-04, at p. 4.

millions of dollars requires a level of competency beyond that of an entity or individual that is small and unsophisticated. Third the creativity required to take a large generation project and re-arrange it in a manner so that each qualifies individually in Idaho for published rate eligibility indicates a level of competency beyond that one should define as small and unsophisticated. Finally, in reviewing the list of present PURPA developers, a majority of the projects in Idaho are being built by developers who clearly are not small or unsophisticated.

The following Table 2 illustrates an estimate of the magnitude of the dollars being expended in Idaho to develop various resources. The cost data are taken from Avista's 2009 IRP.

Table 2

Capital Cost From Avista 2009 IRP (2009 $millions)										
Technology	$/kW	100 kW	1 MW	5 MW	10 MW	30 MW	50 MW	100 MW	150 MW
Biomass Open Loop	5,000	0.5	5.0	25.0	50.0	150.0	250.0	500.0	750.0
Geothermal	5,000	0.5	5.0	25.0	50.0	150.0	250.0	500.0	750.0
Cogeneration	2,000	0.2	2.0	10.0	20.0	60.0	100.0	200.0	300.0
Solar PV	7,500	0.8	7.5	37.5	75.0	225.0	375.0	750.0	1,125.0
Small Scale Wind	3,000	0.3	3.0						
Large Scale Wind	2,000			10.0	20.0	60.0	100.0	200.0	300.0

As the table shows, a 100 kW eligibility cap is more consistent with the concept of providing published rates to small projects. As demonstrated in Table 2, 100 kW projects generally cost $500,000 or less, except for solar at $800,000. Conversely, projects presently eligible for published rates at 10 aMW are highlighted in Table 2. For example, a 30 MW wind project would generate approximately 10 aMW. The total cost to build such a project is approximately $60 million. A solar plant, with its much lower capacity factor, could be as large as 50 or 60 MW, equating to $375 million. Other potential QF project sizes are described in Table 2 as well.

Q. Would requiring developers of QFs larger than 100 kW to negotiate an IRP Methodology-based rate be unduly burdensome on the developer or otherwise unfair?

A. No. With regard to 100 kW and smaller projects, Avista agrees that providing a published rate and avoiding a negotiated IRP Methodology-based avoided cost rate makes sense and is consistent with FERC's requirement. However, for larger QF projects up to 10 aMW of any technology, developers of such projects are necessarily sophisticated and well financed. Moreover, such negotiation would not be unduly burdensome in any sense. Even assuming that the developer is unable to replicate the models used as part of the IRP Methodology, the cost of obtaining any needed expertise would be very small when compared to the overall costs of the project. For example, assuming a conservative figure of 200 hours (5 weeks) of consultant time (which is much more than Avista would expect to be necessary) at a $250 per hour billing rate, the cost of the consultant would equate to $50,000. Table 3 below details the impact of this expense on projects with a nameplate rating of 100 kW, on projects with a nameplate rating of 5 and 10 MW, and projects capable of generating 10 aMW.

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Table 3

Technology	Cost	100 kW	5 MW	10 MW	10 aMW
Biomass Open Loop	50,000	10.00%	0.20%	0.10%	0.10%
Geothermal	50,000	10.00%	0.20%	0.10%	0.10%
Cogeneration	50,000	25.00%	0.50%	0.25%	0.25%
Solar PV	50,000	6.67%	0.13%	0.07%	0.01%
Small Scale Wind	50,000	16.67%			
Large Scale Wind	50,000		0.50%	0.25%	0.08%

The cost of a consultant to assist in calculating or negotiating the avoided cost rate using the IRP Methodology, even in a scenario where 200 hours of consultant time was required at $250 per hour, may be significant for a 100 kW project. But for larger projects such costs are insignificant related to the overall cost of the project. For a 10 aMW large project, for example, such cost is well under one percent, and as low as 0.01%. These consultant fees are smaller than most other costs that will be incurred by a QF developer, including likely permitting and financing fees. Fees relative to smaller developments are also shown in Table 3 to illustrate how a 5 MW and 10 MW project would be affected by $50,000 in consulting costs.

In summary, most of the QF development occurring today in Idaho is <u>not</u> being performed by farmers or ranchers or other small business groups with limited development experience and means. Instead, such development is being completed by experienced, sophisticated, and well financed entities. These developers have the ability and means to negotiate a PURPA contract rate using the IRP Methodology to calculate the actual avoided cost.

Q. If 10 aMW developers do not fit the definition of being small, should they be eligible for published rates?

A. No. As noted earlier, the justification for published avoided cost rates is largely administrative ease for developers that are not well financed and sophisticated. Any developer of a 10 aMW project cannot be fairly characterized as small or unsophisticated. Only truly small projects (i.e., those projects that are at or below 100 kW) should be eligible for published avoided cost rates.

Q. How does Avista's proposal satisfy the Commission's goal of preventing large QFs from disaggregating in order to obtain a published avoided cost rate that exceeds a utility's avoided cost?

A. If the eligibility cap for published avoided cost rates is permanently set at 100 kW it will be very difficult for developers to disaggregate large projects into small enough pieces to take advantage of the published avoided cost rates. Although it may be technically possible in some cases to disaggregate down to several 100 kW projects, it is unlikely that it will be cost effective to do so. Therefore, the 100 kW eligibility cap achieves the Commission's goal of preventing disaggregation by making it both physically and economically difficult for QF developers to disaggregate their projects.

Q. What are the advantages to using the IRP Methodology to establish the rate for large QFs?

A. As discussed above, the current published avoided cost rate is based on a natural gas CCCT SAR. That published avoided cost rate does not reflect the actual avoided costs associated with other QF resources—particularly wind QF resources that are being targeted for acquisition in Avista's Integrated Resource Plan. Use of the IRP Methodology to set the rates for large QFs will ensure that the rate that utilities are required to pay to such QFs more accurately reflects the utilities' actual avoided costs. This will ensure that the utilities' retail customers are not required to overpay for such resources through retail rates.

Q. Are there any other advantages to using the IRP Methodology to set the avoided cost rate for projects larger than 100 kW?

A. Yes. There are several practical advantages to setting the eligibility cap at 100 kW. First, the Commission's goal of ensuring that published rates are available to truly small QFs is satisfied. Also, if the present eligibility cap is lifted, there are several other issues that will need to be resolved that would not necessarily need to be resolved with a 100-kW cap on published rate eligibility. As discussed above, at 10 aMW, the methodology for setting the published avoided cost rates will need to be addressed. Other PURPA issues that need to be addressed if the eligibility cap is 10 aMW include: (i) ownership of environmental attributes associated with QFs, (ii) the appropriate wind integration charge, and (iii) a capacity discount for variable generation resources like wind and solar that do not provide generation at the expected times of system peak. These issues become substantially less important if the eligibility cap is 100 kW and, as a result, are likely resolved by the lower eligibility cap. Also, under Avista's proposal, only those projects that are market competitive with utility options will be built. Finally, and possibly the largest benefit of a 100 kW limit is its simplicity and comprehensiveness. At 100 kW it is very unlikely that developers will disaggregate–physics and economics will prevent such disaggregation. Larger projects continue to receive avoided cost rates, but rates that reflect the utility's actual avoided costs through an IRP Methodology calculation.

Q. Are developers' concerns regarding the 100 kW eligibility cap justified?

A. No. QF developers, and particularly developers of wind QFs, have argued against lowering the eligibility cap in substantial part because they are concerned that the avoided cost rate calculated using the utilities' IRP methodologies will be lower than the published avoided cost rate. This argument, however, should not advance their cause. If anything, this argument should be viewed as evidence of the need to either permanently set the eligibility cap for the published avoided cost rate at 100 kW or substantially modify the methodology for setting the published avoided cost rate.

Avista's IRP Methodology establishes a rate that reflects Avista's actual avoided cost. If the published avoided cost rate accurately reflected the utility's actual avoided cost for their projects, developers should be indifferent as to whether the avoided cost rate was calculated using the IRP Methodology or whether published avoided cost rates were applied.

VI. ALTERNATIVES TO IRP METHOD FOR PROJECTS LARGER THAN 100 KW AND UP TO 10 AMW

Q. Is there an alternative to the IRP Methodology for projects of sizes between 100 kW and 10 aMW?

A. Yes, although it would not afford customers the same price protection as the IRP Methodology because it would be subject to arbitrage by QF developers where market conditions move faster than published rates are updated by the Commission. There are actually two potential alternatives to the IRP Methodology, though one likely would be simpler and more consistent with historical precedent.

Q. **What is one method available to the Commission?**

A. The Commission could re-visit the issues presented in case GNR-E-09-03. In that case, Commission Staff developed a straw man wind SAR proposal to set published rates for variable generation resources such as wind and solar. Though that proceeding was vacated, in light of the current situation it might make sense to re-opening the issues that were to be addressed in that proceeding.

Q. **What is the simpler method?**

A. The simpler method would be to continue to use the present SAR methodology and resource (i.e., a gas-fired CCCT). However, for resources that are not expected to provide any significant on-peak capacity contribution (e.g., wind and solar) an on-peak capacity discount would be applied. The on-peak capacity discount concept was illustrated in Joint Utility comments in the recent wind SAR straw man proceeding.[17]

In addition to the capacity discount, a more frequent update of the key input assumptions is essential, including the price forecast for natural gas. To the extent this method is pursued, Avista proposes that the annual EIA forecast be implemented due to its public availability.

Q. **Does this conclude your direct testimony?**

[17] See Case No. GNR-E-09-03.

A. Yes.

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BEFORE THE IDAHO PUBLIC UTILITIES COMMISSION

IN THE MATTER OF THE COMMISSION'S INVESTIGATION INTO DISAGGREGATION AND AN APPROPRIATE PUBLISHED AVOIDED COST RATE ELIGIBILITY CAP STRUCTURE FOR PURPA QUALIFYING FACILITIES	))))))))	CASE NO. GNR-E-11-01 EXHIBIT NO. 101 TO THE DIRECT TESTIMONY OF CLINT KALICH

FOR AVISTA CORPORATION

Analysis of Solar Contributions to Utility Needs

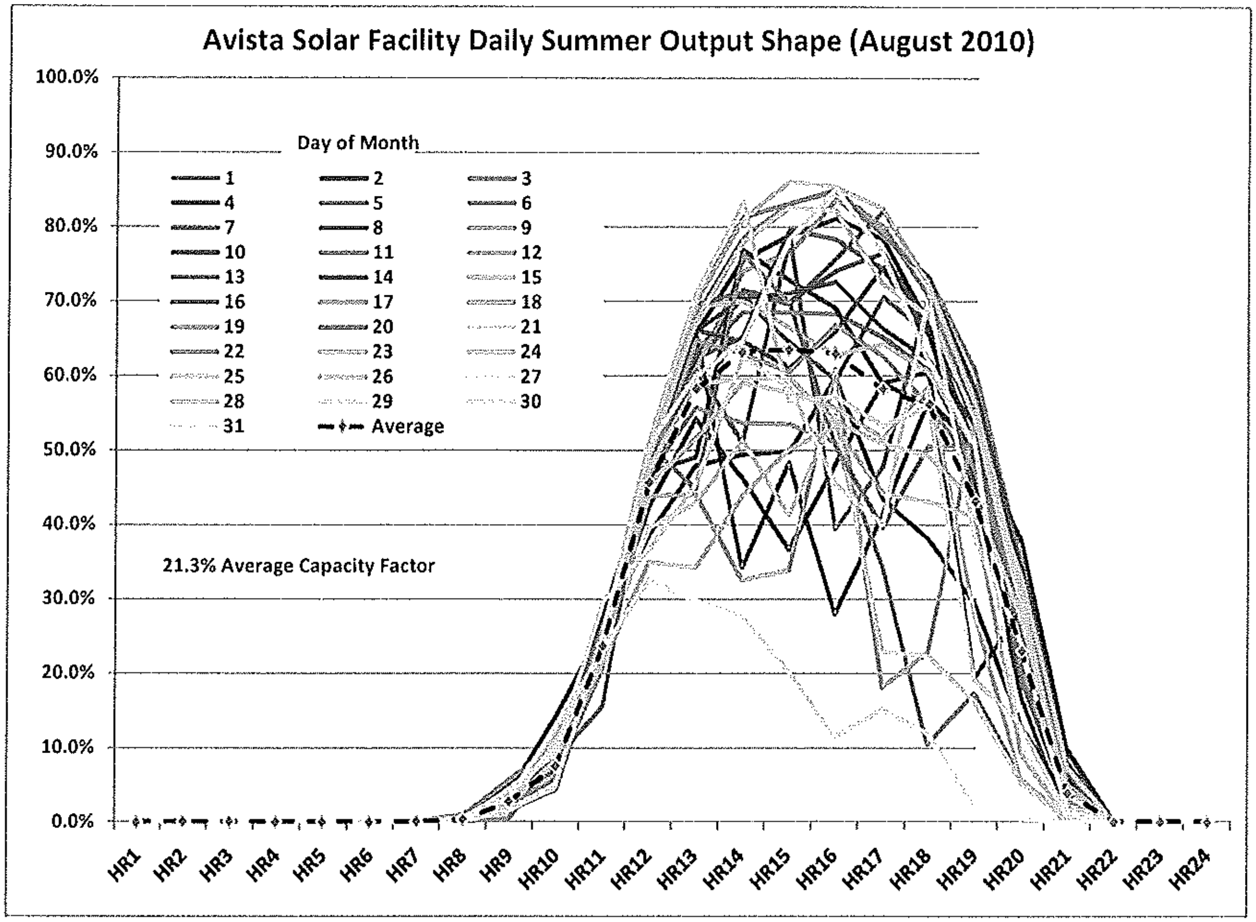
Introduction

Many advocates of solar point to its on-peak generation profile and conclude that this bias warrants a higher price than wind and lessens the reliability impacts of the resource. There is evidence that, unlike wind, solar does on average provide generation during periods where utility loads are higher than for wind. However, this fact does not eliminate the operational and valuation concerns associated with solar. Absent some storage medium, which is unlikely for QF projects which will be comprised of photovoltaic panels, solar does not greatly reduce the capacity needs of the utility. Yet solar appears to have many of the operational problems associated with wind resources; it is an unpredictable variable resource. Much of this unpredictability comes from various weather variables that affect output, including cloud-cover, precipitation, temperature and dust. Avista presents the following analyses in support of its view that eligibility for published avoided cost rates for solar, like wind, QFs should be limited to 100 kW.

Solar Experiences Significant Day-to-Day Variability

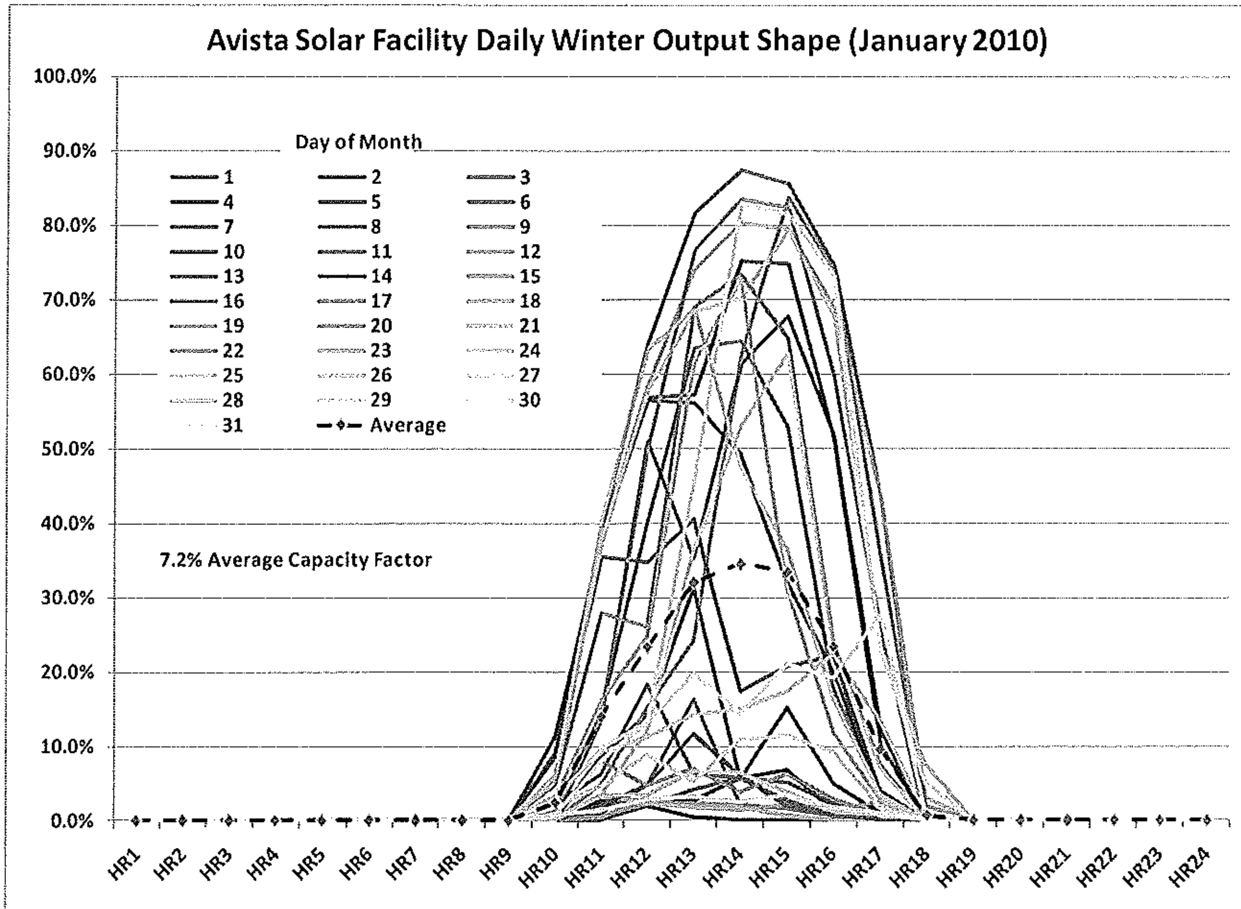
Avista in 2009 installed 3.5 kW-DC photovoltaic solar facility on the top of its corporate headquarters. Chart 1 below details the hourly summer profile of Avista's solar facility in 2010. Chart 2 illustrates the same for a winter profile, defined as January 2010. As can be seen in both cases, the variability across the on-peak hours is substantial. In the case of winter, the average capacity factor is 7.2% for solar, yet variability during on-peak hours is between zero and 87%. In the winter, output for solar can be zero even during solar's peak output hours (12:00p-4:00p).

Chart 1



In the summer the average solar capacity factor of Avista's facility was 21.3%, with a range in the on-peak hours of between zero and 86%. During the summer when average production is the highest, output during the resource's highest production hours (1:00p-5:00p) ranged greatly, between 11.6% and 87.4% in 2010, versus an average of 61.9%.

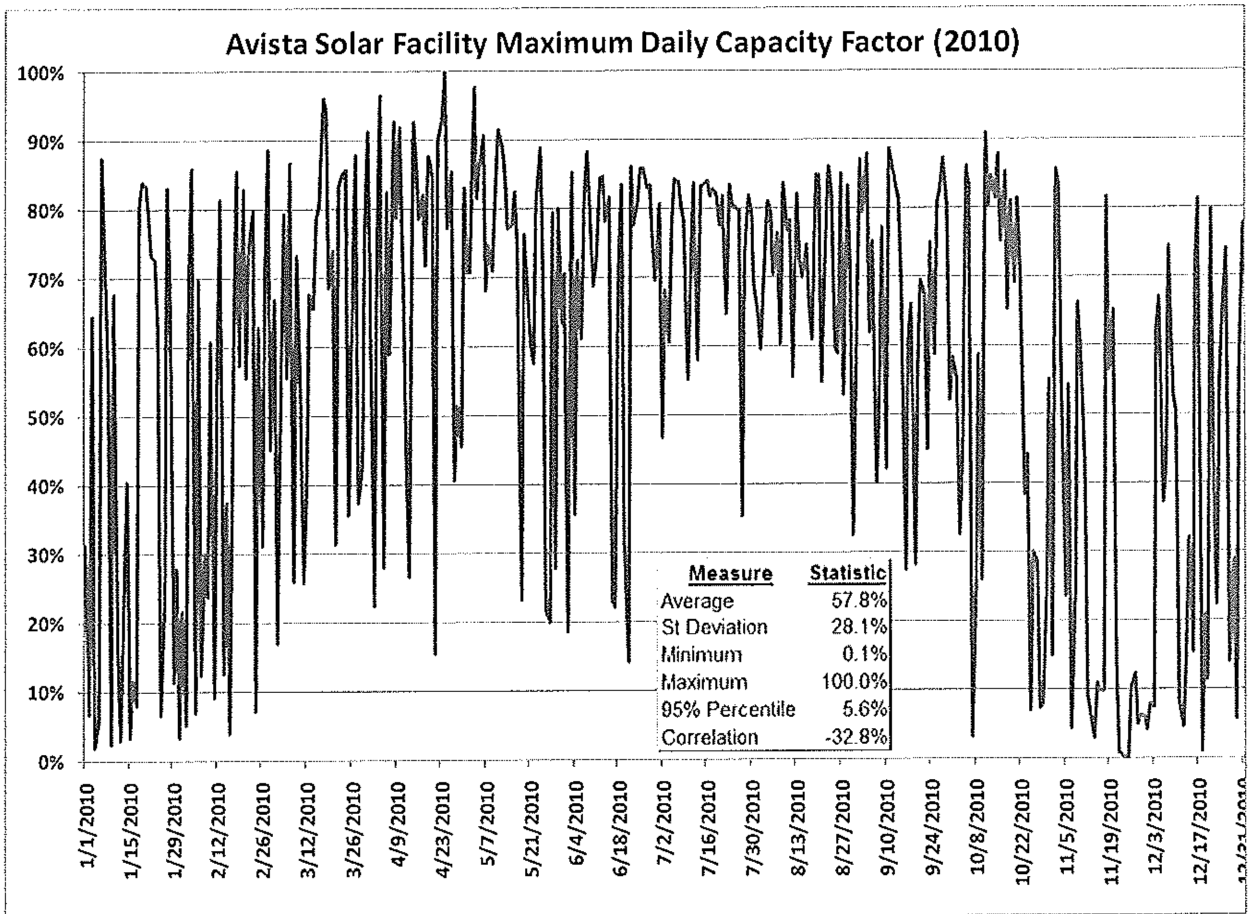
Chart 2



Solar is Not Correlated to System Needs (Peak Demand)

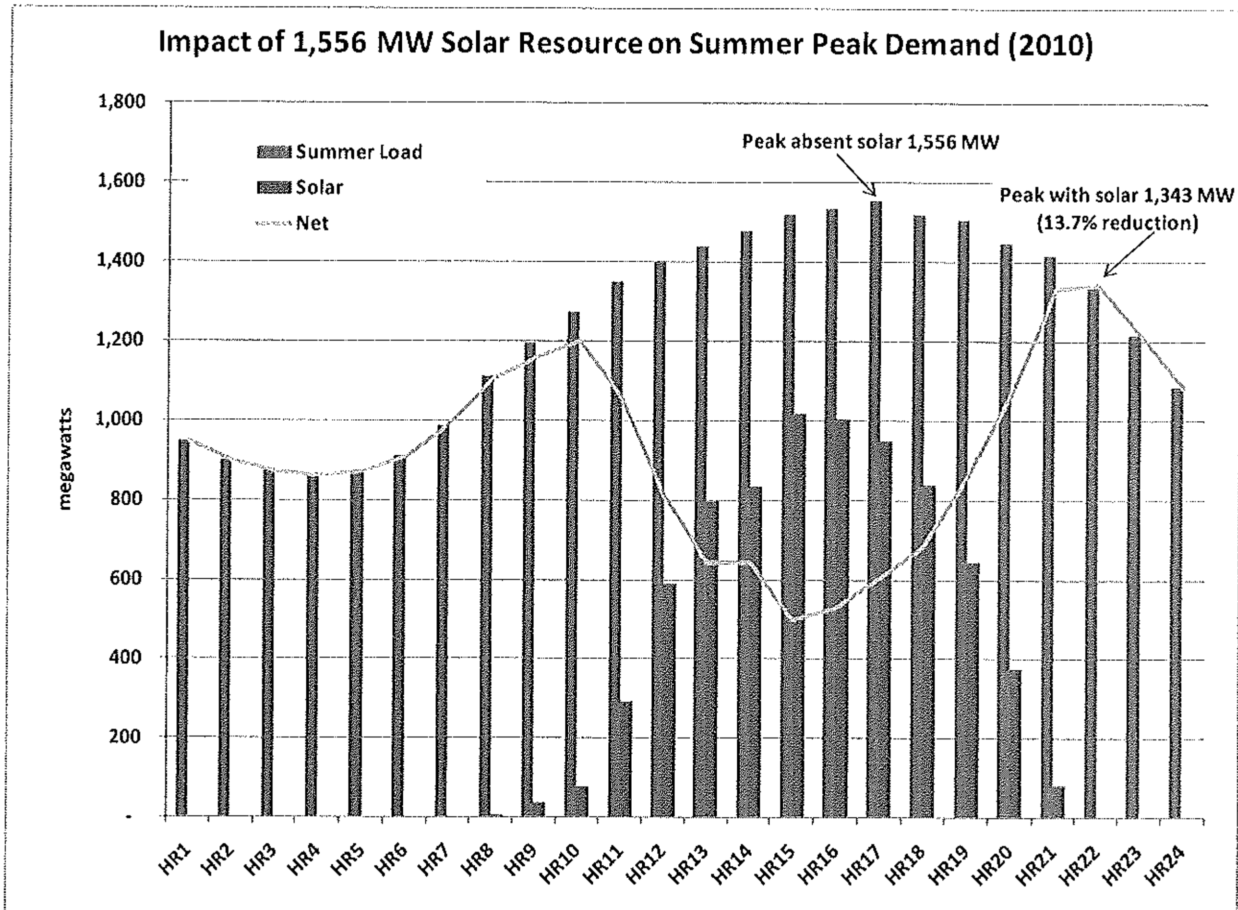
Solar output is not consistent or "reliable." As a result, Avista's other resources will have to stand ready to backup the solar resource. In 2010 the correlation of Avista's solar facility to Avista's daily peak demand was -33%, indicating no correlation. Chart 3 below provides the peak daily output profile of Avista's solar test facility during 2010.

Chart 3



Although Chart 3 provides a good illustration of the variability of solar, it does not explain the capacity contribution of the resource. Solar, while generating on-peak energy, does not greatly reduce a utility's need to construct capacity resources. To illustrate this, Avista analyzed its peak winter and summer load days during 2010. In each case it was assumed that a solar facility of the same size as the peak demand hour was constructed (otherwise the impact would be difficult to visualize). As Chart 4 shows, during the summer months the solar facility would reduce the peak need of the utility by only 13.7% of the nameplate of alternating current rating of the resource.

Chart 4



The facility generated a significant amount of electrical energy on this hot day, but its output fell substantially before Avista's load fell. Therefore Avista's peak need for non-solar resources was simply *shifted* from hour ending 17 (4:00p-5:00pm) to hour ending 22 (9:00p-10:00p). A 13.7% reduction was achieved. A similar analysis was completed by the Northwest Power and Conservation Council's (NPCC) 6th Power Plan using the expected solar output of southern Idaho. NPPC's analysis revealed an even smaller peak reduction of 9%.

The same analysis performed for the winter, using both Avista's and the NPCC's solar profiles, found that *during the winter solar will provide no peak capacity reduction.*

BEFORE THE IDAHO PUBLIC UTILITIES COMMISSION

IN THE MATTER OF THE COMMISSION'S	)	
INVESTIGATION INTO	)	CASE NO. GNR-E-11-01
DISAGGREGATION AND AN	)	
APPROPRIATE PUBLISHED AVOIDED	)	
COST RATE ELIGIBILITY CAP	)	EXHIBIT NO. 102 TO THE
STRUCTURE FOR PURPA QUALIFYING	)	DIRECT TESTIMONY OF
FACILITIES	)	CLINT KALICH
	)	

FOR AVISTA CORPORATION

PUPRA History and 2009 - 2010 PURPA Activity
12/13/2010

Existing PURPA Projects

Existing Projects	Start Date	Technology	Capacity	Location	Ownership
Project 1	8/1/1966	Hydro	17.7 MW	Spokane, WA	City of Spokane
Project 2	2/12/1982	Hydro	0.22 MW	Clark Fork, ID	James White
Project 3	6/1/1982	Hydro	0.02 MW	Northpoint, WA	Glenn Phillips
Project 4	5/1/1986	Hydro	1.4 MW	Northpoint, WA	Glenn Phillips
Project 5	9/1/1987	Hydro	0.9 MW	Lucille, ID	David Cereghino
Project 6	4/1/1988	Hydro	1.41 MW	Weippe, ID	Ford Hydro Limited
Project 7	2/12/1999	Hydro	1.3 MW	Kettle Falls, WA	Hydro Tech Systems
Project 8	7/22/2003	Thermal - Wood	62 MW	Lewiston, ID	Clearwater Paper Company
Project 9	10/1/2006	Thermal - Wood	6 MW	Plummer, ID	Stimson Lumber
		SUM	91 MW		

PURPA Inquiries

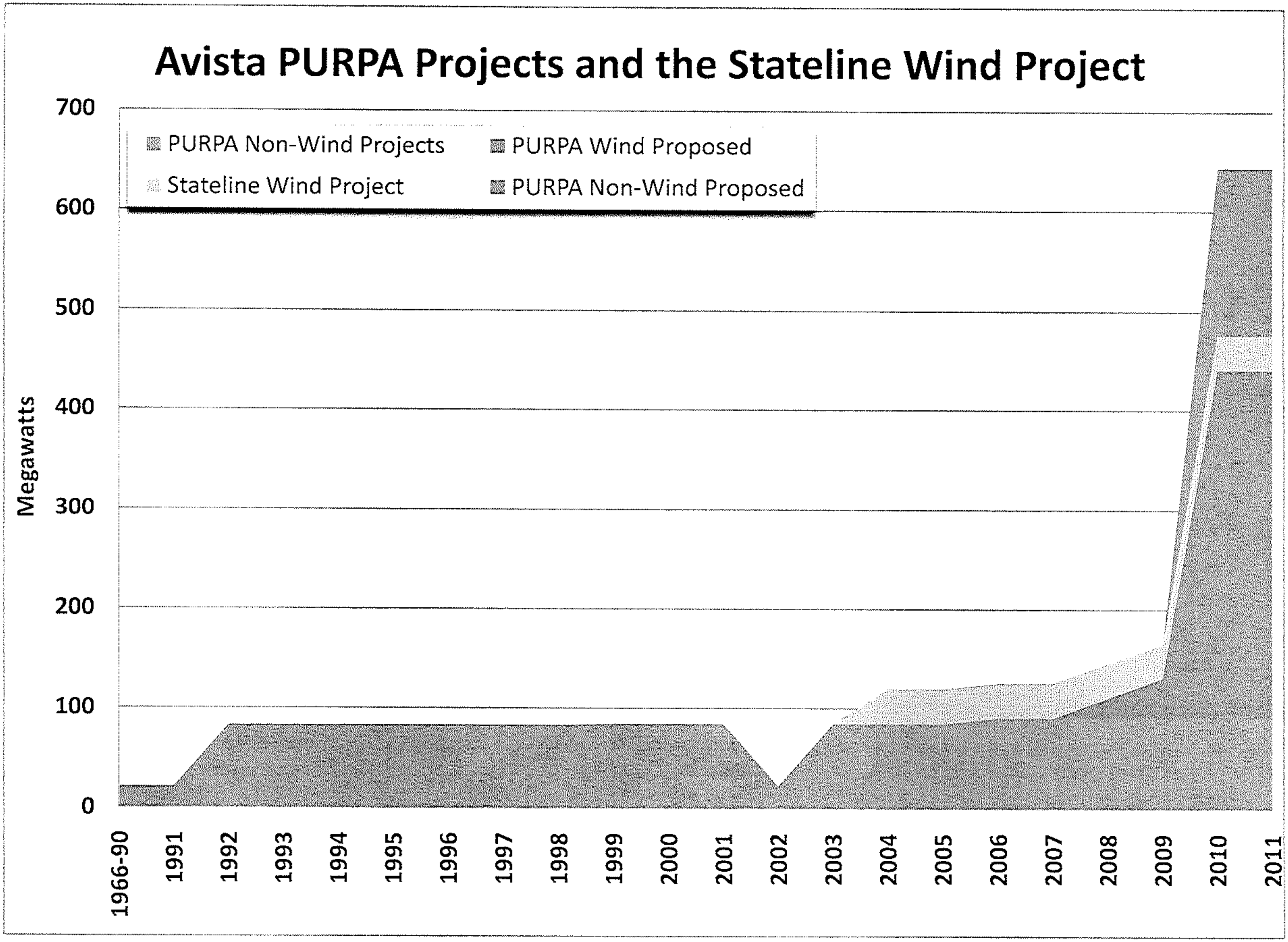
1) Projects that have made inquiries and we've sent them the materials.
No further negotiations have taken place

Project	Date	Last Communication	Technology	Capacity	Location
Project 1	Nov-09	Mar-10	Wind	20 MW	SW Montana
Project 2	Mar-10	Apr-10	Landfill Gas	1 MW	Coeur d'Alene, ID
Project 3	Mar-10	Mar-10	Biomass	10 MW	SW Oregon
Project 4	Apr-10	Apr-10	Wind	10 MW	Reardan, WA
Project 5	Jun-10	Dec-10	Hydro	0.4 MW	Northpoint, WA
Project 6	Jul-10	Jul-10	Wind	80 MW	SW Washington
Project 7	Aug-10	Aug-10	Biomass	9 MW	SW Oregon
Project 8	Dec-10	Dec-10	Biomass	80 MW	E. WA
Project 9	Dec-10	Dec-10	Wind & Solar	70 MW	Washington
			Sum	280 MW	

2) Projects that have made development progress and contractual progress
All of these projects proposed to deliver to Avista in Idaho

Project	Date	Last Communication	Technology	Capacity	Location
Project 1	Jan-08	Nov-09	Wind	20 MW	Norris, MT
Project 2	Jan-10	Sep-10	Bio-gas	7 MW	Blanchard, ID
Project 3	Jun-10	Jun-10	Wind	20 MW	Grangeville, ID
Project 4	Jun-10	Jun-10	Wind	20 MW	Grangeville, ID
Project 5	Jun-10	Jun-10	Wind	20 MW	Grangeville, ID
Project 6	Jun-10	Jun-10	Wind	20 MW	Grangeville, ID
Project 7	Jun-10	Jun-10	Wind	20 MW	Grangeville, ID
Project 8	Jun-10	Nov-10	Wind	30 MW	Columbus, MT
Project 9	Oct-10	Dec-10	Wind	10 MW	Oregon
Project 10	Nov-10	Dec-10	Wind	10 MW	Oregon
			Sum	177 MW	

	1966-90	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011
PURPA Non-Wind Projects																						
Annual MW (Capability)	21.7		62.0							1.3			(62.0)	62.0			6.0					
Cummulative MW	21.7	21.7	83.7	83.7	83.7	83.7	83.7	###	83.7	85.0	85.0	85.0	23.0	85.0	85.0	85.0	91.0	91.0	91.0	91.0	91.0	91.0
PURPA Wind Proposed																						
Annual MW (Capability)																			20	20	310	
Cummulative MW	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	20	40	350	350
PURPA Non-Wind Proposed																						
Annual MW (Capability)																			0	0	168.4	
Cummulative MW	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	168.4	168.4
Stateline Wind Project															35	35	35	35	35	35	35	35



Avista PURPA Projects and the Stateline Wind Project
PURPA Non-Wind Projects
PURPA Wind Proposed
Stateline Wind Project
PURPA Non-Wind Proposed
Megawatts
700
600
500
400
300
200
100
0
1966-90
1991
1992
1993
1994
1995
1996
1997
1998
1999
2000
2001
2002
2003
2004
2005
2006
2007
2008
2009
2010
2011