Witness OCS- 1D

BEFORE THE PUBLIC SERVICE COMMISSION OF UTAH

In the Matter of the Application of Rocky Mountain Power for Approval of Changes to Renewable Avoided Cost Methodology for Qualifying Facilities Projects Larger than Three Megawatts	: : : : :	Docket No. 12-035-100 Phase 2 All Other Issues

DIRECT TESTIMONY OF

RANDALL J. FALKENBERG

ON BEHALF OF THE

OFFICE OF CONSUMER SERVICES

REDACTED VERSION

Subject to Rule 746-100-16

March 29, 2013

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. Randall J. Falkenberg, PMB 362, 8343 Roswell Road, Sandy Springs, Georgia 30350.

Q. PLEASE STATE YOUR OCCUPATION, EMPLOYMENT, AND ON WHOSE BEHALF YOU ARE TESTIFYING.

A. I am a utility regulatory consultant and President of RFI Consulting, Inc. ("RFI"). I am appearing on behalf of the Office of Consumer Services ("OCS").

Q. WHAT CONSULTING SERVICES ARE PROVIDED BY RFI?

A. RFI provides consulting services related to electric utility system planning, energy cost recovery issues, and revenue requirements.

Q. PLEASE SUMMARIZE YOUR QUALIFICATIONS AND APPEARANCES.

A. My qualifications and appearances are provided in Exhibit OCS 1.1. I have participated in numerous cases involving PacifiCorp and Rocky Mountain Power (or the "Company") power costs, capacity acquisition and other issues over the past ten years.

I. INTRODUCTION AND SUMMARY

Q. WHAT IS THE PURPOSE OF THIS TESTIMONY?

A. I discuss the Company's proposal to change the methodology used to determine avoided cost payment rates for renewable Qualifying Facilities ("QFs") larger than three MW. This round of testimony is pursuant to the Public Service Commission's ("Commission") orders of November 13, 2012 and December 20, 2012. In the latter order, the Commission determined that the Company should file testimony in Phase 2 of this proceeding to propose changes to the avoided cost methodology for large renewable QFs.

Q. PLEASE SUMMARIZE YOUR CONCLUSIONS AND RECOMMENDATIONS.

A. My conclusions and recommendations are as follows:

1. The market proxy method no longer produces reasonable avoided costs for large, renewable QFs. The method was appropriate at a time when the Company was rapidly expanding its fleet of wind resources and when wind resources were expected to be part of the least cost expansion plan. At present neither condition is applicable. The Company has no immediate plan to add new wind resources, and any such resources expected to be installed in the next five to ten years are only included to meet Renewable Portfolio Standards ("RPS") in other states.

2. The PDDRR method provides a reasonable basis for determining the avoided costs for renewable QFs. I generally agree with the mechanics of the Company's proposed PDDRR method. However, I recommend some limited modifications.

3. The Company has applied the Draft 2012 Wind Integration Study ("WIS") results to derive the integration costs for wind QFs. The Study has not been approved by the Commission nor endorsed by the Technical Review Committee ("TRC"), but is the most practical alternative available at this time. Consequently, the proposed Wind Integration cost of $4.35/MWh should be updated after the 2012 WIS has been fully vetted.

4. The Company provides little support for its assumption that wind and solar projects impose the same integration costs. I recommend the Commission require the Company to perform a solar integration study and update the avoided costs when the results become available and the study has been vetted.

5. The Company's proposed method for assessing a capacity payment for wind QFs is flawed because it doesn't result in equal reliability benefits for Company-owned thermal units and renewable QFs. I propose an alternative approach which supports a capacity contribution of 13.8% for wind QFs. These results should be updated periodically.

6. For solar QF capacity, there is no Company specific actual data. For this reason, I don't oppose the Company's method for assessing a capacity payment for solar QFs, but recommend the entire analysis should be revisited when actual data becomes available.

II. THE MARKET PROXY AVOIDED COST METHODOLOGY

Q. WHAT IS THE REQUIREMENT UNDER THE PUBLIC UTILITIES REGULATORY POLICIES ACT OF 1978 (“PURPA”) CONCERNING AVOIDED COST PAYMENTS TO QFS?

A. PURPA requires utilities to purchase power from QFs at avoided cost, as determined by the state regulatory commission. There are many complexities and nuances in the determination and application of avoided costs, but for our purposes, the guiding principle should be that of “ratepayer indifference.” In other words, avoided cost payments should be set at a level where ratepayers are indifferent as to whether the utility generates the power itself, or purchases it from a QF. Pursuant to the Commission’s October 31, 2005 order in Docket No. 03-035-14 (“the 2005 Order”) the Company has used the Partial Displacement Differential Revenue Requirement (“PDDRR”) and Market Proxy methods for determining avoided costs for non-renewable and renewable QFs respectively.

Q. PLEASE EXPLAIN THE DIFFERENCE BETWEEN THE PDDRR AND MARKET PROXY METHODS FOR DETERMINING AVOIDED COSTS.

A. The PDDRR method determines avoided costs on the basis of the difference in revenue requirements resulting from an increase in the amount of QF capacity on the system. The methodology uses two Generation and Regulation Initiative Decision Tool (“GRID”) Model runs - one with and one without a hypothetical QF project to determine the avoided costs until the next thermal addition (the “avoided unit”) in the expansion plan is expected to be installed. At that time, a capacity credit is included to reflect the fixed costs of the avoided unit and the monthly avoided energy costs (as determined from GRID) are limited to be no more than the level of the avoided unit. For non-renewable QFs the most recently updated PDDRR avoided cost is \$44.23/MWh based on the most recent (Q4 2012) Schedule 38 filing.

The Market Proxy method is based on the contract costs of the most recently signed renewable contract. The Market Proxy method currently produces payments of $58.63/MWh based on the 2009 Dunlap contract. Dunlap was the last (non-QF) wind resource contract signed by the Company.

Q. WHAT AVOIDED COST METHODOLOGY IS THE COMPANY PROPOSING IN THIS CASE.

A. The Company is proposing to replace the Market Proxy method with the PDDRR method incorporating adaptations to reflect the integration costs and capacity contributions of wind and solar QFs.

Q. WHAT AVOIDED COSTS WOULD RESULT FROM RMP'S PROPOSAL?

A. Based on current forecasts, the Company proposal would pay the renewable QFs $37.43/MWh as shown in Mr. Duvall's Table 1. This figure would be updated periodically by the Company.

Q. DOES OCS AGREE WITH THE COMPANY'S PROPOSAL IN THIS CASE?

A. OCS agrees with the Company that the Market Proxy method is no longer appropriate and that the PDDRR method should be adapted and used to provide proper avoided costs for renewable (wind and solar) QF resources. While OCS does not endorse every detail of the Company's proposal (nor has it undertaken a detailed analysis of the Company's GRID model studies) the framework proposed by the Company is reasonable.

Q. EXPLAIN WHY THE MARKET PROXY METHOD IS NO LONGER REASONABLE.

A. The Market Proxy method was implemented at a time when the Company had a goal of installing 1,400 MW of wind generation and was rapidly expanding its fleet of wind generation resources to meet that goal. Use of the most recent contract price was the best way to achieve ratepayer indifference. At that time, that Market Proxy provided a practical, verifiable estimate of the costs customers would pay for wind generation acquired by the Company to meet the 1,400 MW goal.

Because wind contract prices have varied substantially over time[1] the Market Proxy contract price needs to be current to maintain ratepayer indifference. Over the past decade there has been a sort of "boom-bust" cycle for wind turbines and prices have risen and fallen in response to market conditions and a host of other factors. This has changed the cost of wind development and impacted contract prices. A coal contract several years old is not reflective of current market prices for coal. Likewise, an outdated wind power contract cannot provide an indication of current market prices. Further, if there is no need for additional wind generation, the Market Proxy method is irrelevant.

Q. WHAT ELSE HAS CHANGED SINCE THE 2005 ORDER APPROVED THE MARKET PROXY METHOD?

A. Fuel prices have varied substantially. When fuel prices were much higher the economics of wind generation was attractive for offsetting thermal generation and it was included in the least cost plan. Likewise, there have been substantial variations in the market for Renewable Energy Credits ("RECs"). At times REC prices were very high, providing substantial additional revenues. When these factors were coupled with the Company's goal of installing 1,400 MW of new wind generation, the Company was rapidly expanding its wind fleet.

Those conditions are no longer present. The Company achieved its wind expansion goals. Gas prices and the value of RECs have fallen. Further, the Company's load forecast and expansion plans have changed substantially as well, and the Company has

[1] For example, the GRID model output report shows 2013 prices ranging from less than $[redacted]/MWh for Combine Hills and Rock River, to $[redacted]/MWh for the Top of the World contract. These varying contract prices are primarily due to different signing dates.

acquired substantial new thermal resources, delaying the need for additional resources. No new thermal resources are expected to be included in the Company's plans until the mid to late 2020's. The GRID Model study assumes that the Company will rely on Front Office Transactions (FOTs) and DSM until 2024 before adding new thermal capacity. This will not be resolved, however, until the IRP is finalized but these assumptions appear to track scenarios currently being reported in the IRP process. All of this suggests that avoided costs have changed substantially since the 2005 Order was issued. While the PDDRR method is designed to reflect such changes in avoided costs, the Market Proxy method is not.

Q. THE BLUE MOUNTAIN DECISION RESULTED IN THE COMPANY FILING THIS CASE. IN THAT DECISION, THE COMMISSION FOUND THAT INCLUSION OF WIND RESOURCES IN THE IRP SUPPORTED CONTINUATION OF THE MARKET PROXY METHOD. PLEASE COMMENT.

A. There is a very important difference in the purpose of the wind resources included in the Company's IRP in 2005 and those being included in the current IRP. In the most recently completed (and currently developing) IRPs the wind (and solar) resources are being included to meet RPS mandates in California, Oregon and Washington. The currently approved multi-state jurisdictional allocation methodology ("The 2010 Protocol) expires in 2016. There is no allocation method for post 2016 RPS resources presently agreed upon in the on-going Multi State Process discussions. According to Mr. Duvall **"***The primary issue is whether the full costs and RECs are assigned situs to the states with RPS requirements, or only the costs which exceed the costs PacifiCorp would have otherwise incurred are assigned situs to the states with the RPS requirements*."[2] As a result, the basis for including these resources in the IRP is vastly different than in 2005 and the ultimate cost

[2] Duvall Direct Testimony, page 14.

recovery mechanism is presently undecided, but may be much different from that applied to the Company's existing fleet of wind resources.

Further, in the Company's current IRP, there are various scenarios being considered which do not include RPS resources and the resources in question may not even be built as alternative compliance methods are possible. For example, it may be possible for the Company to purchase enough RECs to avoid these resources. Alternatively, QFs located in those states may provide the necessary renewable energy to meet the RPS. There has been, for example, expansion of wind QFs in Oregon in recent years. In Oregon, there is also a rate impact test which may reduce or even eliminate the RPS requirement. Further, the Washington RPS does not allow for QFs located in Utah (or even the hypothetical Company owned IRP resources located in Wyoming) to be used for compliance purposes. Consequently, OCS agrees with the Company that the mere inclusion of the RPS wind resources in the IRP does not justify the continued use of the Market Proxy method.

Q. PLEASE COMMENT ON THE EQUITY OF CONTINUING THE MARKET PROXY METHOD IN LIGHT OF THESE CIRCUMSTANCES?

A. Continuing to use the Market Proxy method does not support the goal of ratepayer indifference. As Mr. Duvall explains in his testimony, only a small portion of the RECs obtained from the renewable QFs would be useable to customers in the western states. As a result, the Utah customers would be paying more than necessary to provide a rather small benefit to the states with RPS requirements.

Q. HAS THE USE OF THE MARKET PROXY METHOD BEEN SUCCESSFUL IN FOSTERING THE DEVELOPMENT OF WIND QFS IN UTAH?

A. No. At present there is only one wind QF project in Utah, the 18 MW Spanish Fork QF. Though there are some projects under development, there apparently have been many delays and other problems which have lead to little or no QF wind development for RMP in Utah. From the data provided by the Company in its IRP (as well as NREL information I've reviewed), it appears that potential wind capacity factors in Utah are rather low suggesting economical development of new wind resources in the state is difficult. Naturally, if there are unique or site specific factors that allow a wind QF to successfully develop projects in the state they should be afforded every opportunity to do so, through payments based on a properly determined avoided costs which neither subsidize ratepayers or developers.

Q. CAN YOU SUMMARIZE THE MAIN POINTS OF THIS PORTION OF YOUR TESTIMONY?

A. Yes. The Market Proxy method is no longer appropriate for four main reasons: First, the Company is not actively acquiring wind resources. As a result, the prices derived under the method have become four years out of date. Second, the first wind resources selected in the expansion plan are not selected due to their economic benefits, but rather for their assumed RPS compliance in other states. Third, wind resources included in the IRP are based on meeting future RPS requirements in the Company's western states and may never actually be built. Finally, the Company does not now expect to build additional capacity of any kind for quite some time and fuel costs are now much lower, suggesting avoided costs are now much lower than when the 2005 Order was issued.

III. PDDRR METHODOLOGY IMPLEMENTATION FOR RENEWABLE QFS

Q. WHAT IS OCS' POSITION REGARDING THE PROPER METHODOLOGY FOR DETERMINATION OF AVOIDED COSTS FOR RENEWABLE QFS?

A. OCS supports use of the PDDRR method, along the lines proposed by the Company. The PDDRR method has been in use for non-renewable QFs for several years, is easily updated and remains current. It provides the most reasonable basis for determining avoided costs for renewable QFs. However, it does need to be adapted to reflect the differences between thermal and renewable resources. The Company has proposed such modifications, and I will address those.

<u>Integration Costs</u>

Q. SHOULD INTEGRATION COSTS BE REFLECTED IN THE PDDRR METHOD?

A. Yes, the reality of such costs is well established. If renewable QFs do not pay for their full integration costs, ratepayers will likely make up the difference, contrary to the goal of ratepayer indifference. Consequently, the Company's proposal to reflect some level of integration costs is proper.

Q. WHAT OPTIONS ARE AVAILABLE FOR DETERMINATION OF THE INTEGRATION COSTS FOR WIND QFS?

A. Determining integration costs requires isolating the level of reserves required for additional wind capacity. There are really three choices available to the Commission: the 2010 Wind Integration Study ("WIS"); the analyses of actual reserve requirements presented by the Company in recent general rate cases ("GRC"); and the 2012 draft WIS study. Of these three, the latter is the most practical choice. The 2010 WIS and prior actual reserve studies were quite controversial and are now outdated. The Company's actual reserve study from the last GRC also did not isolate the impact of additional wind requirements, which leaves the 2012 draft WIS as the only option available that provides the necessary data. However, I have some concerns regarding the Company's draft 2012 WIS and the proposed use of wind integration costs for solar renewable projects.

Q. PLEASE DISCUSS THE COMPANY'S USE OF ITS DRAFT 2012 WIND INTEGRATION STUDY.

A. The Company has estimated the integration costs for QF wind projects over the next 20 years to equal $4.35/MWh on a levelized basis.[3] This was determined by performing two runs with the GRID model, varying the level of reserves based on the results of the 2012 WIS draft report. The study has not yet been vetted by regulators in Utah (or elsewhere to my knowledge) nor does it presently carry endorsement from the TRC. The study is quite complex and raises a number of difficult issues. However, this case does not really present the best forum for evaluation of the study by the Commission.

Q. WHY WOULD IT BE BETTER TO USE THE RESULTS OF THE 2012 WIS THAN THE EARLIER STUDIES?

A. From my participation in the TRC, and from monitoring comments during IRP stakeholder meetings, I believe there is a general consensus that the 2012 WIS is an improvement over the 2010 WIS, and it is certainly more current. Consequently, it is acceptable to use the study in the manner proposed by the Company for now. Once it has been fully vetted by the TRC and the Commission in the IRP process or a future GRC an updated analysis should be performed. Note, however, this does not imply I am endorsing the study carte blanche, nor proposing that it be used in a general rate case without any adjustments.

Q. PLEASE COMMENT ON THE USE OF THE 2012 WIS RESULTS TO DETERMINE INTEGRATION COSTS FOR SOLAR RESOURCES.

[3] This figure differs from that reported in the 2012 WIS report. The 2012 Report integration cost, $2.55/MWh, represents the cost of integrating the existing wind resources on its system for 2011. The Company's $4.35/MWh figure in this docket reflects the Company's estimated cost of integrating additional wind QFs levelized over the next twenty years.

A. This proposal is problematic. In the response to OCS 2.7 the Company acknowledged it had performed no analysis to determine solar integration costs. There is no real evidence presented by the Company to support the idea that wind and solar integration costs are exactly equal or even close approximates. Further, the Company does not even have actual data for solar projects on its system, making a realistic analysis quite difficult.

Q. IS IT LIKELY THAT WIND AND SOLAR WILL HAVE THE SAME OR SIMILAR INTEGRATION COSTS?

A. No.

Q. WHAT IS YOUR RECOMMENDATION REGARDING SOLAR INTEGRATION COSTS?

A. OCS will review comments by other parties regarding this issue, and may be persuaded by their evidence to take a position later. However, the Company should be directed to perform a solar integration study as there may be solar projects required to meet RPS requirements in western states in the coming years, and it will be necessary to remove those integration costs from Utah revenue requirements. A proper solar integration study will be necessary for these purposes, as well as for accurate determination of avoided costs for solar QFs.

<u>Wind and Solar Capacity Contributions</u>

Q. PLEASE DISCUSS THE COMPANY'S PROPOSED CAPACITY CONTRIBUTIONS FOR WIND AND SOLAR QFS.

A. The Company proposes a capacity credit of 4.1% of nameplate wind QF capacity, 11.5% for energy oriented solar QFs and 25.9% for peak tracking solar facilities. The wind figures are based on actual historical generation data for wind projects as it occurred at the time of the Company's 100 highest peak hours for each year from 2007-2011. The solar results are based on data obtained from the National Renewable Energy Lab ("NREL").

Though the two analyses use the same statistical framework, I will concentrate on the wind results only. While my comments related to wind capacity contribution may have equal validity when applied to solar, the lack of PacifiCorp specific actual data makes me reluctant to make a recommendation regarding solar. OCS would again welcome insights related to the solar issue from other parties and may take a position regarding the solar capacity contribution later in this proceeding.

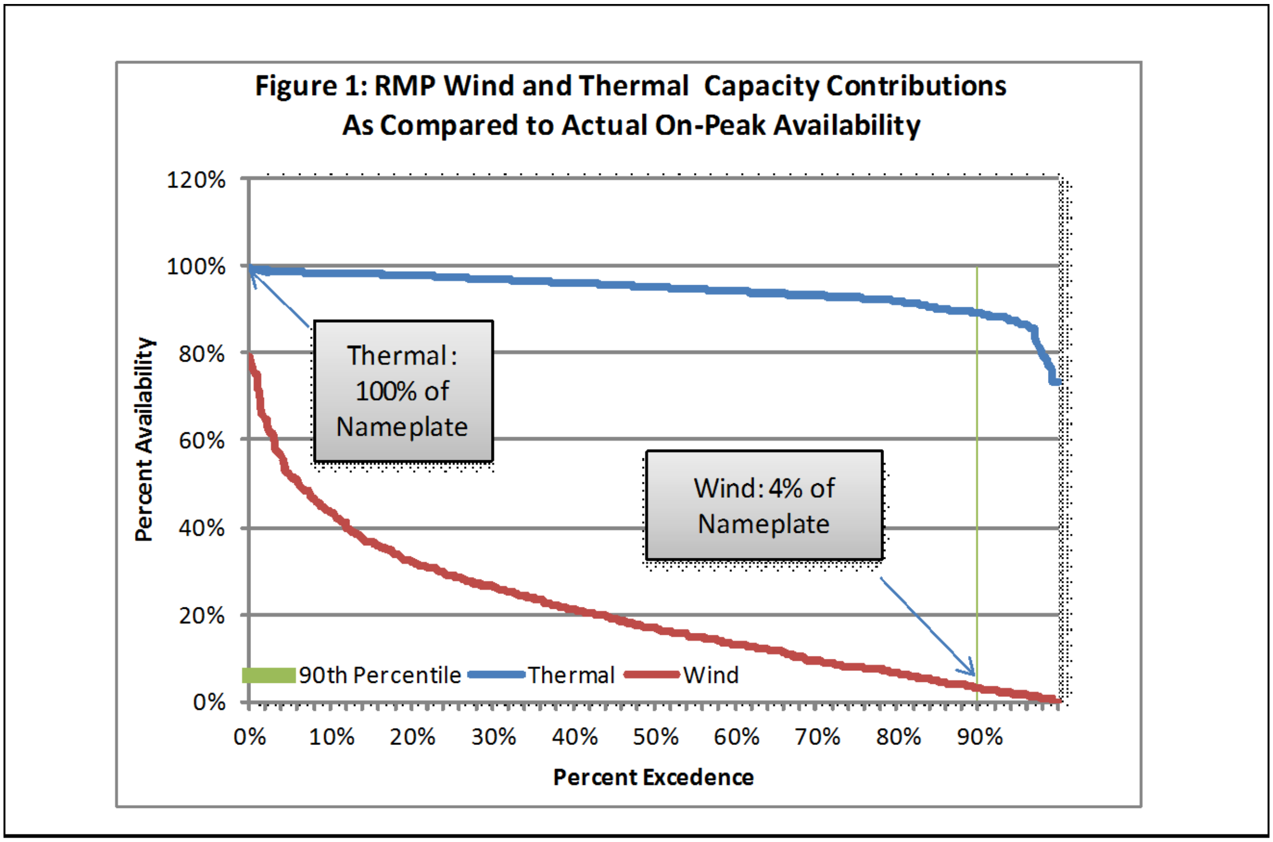
Q. WOULD THE COMPANY'S PROPOSED WIND CAPACITY CONTRIBUTION RESULT IN PROPER COMPENSATION FOR WIND QFS?

A. No, because wind QFs would be compensated for a lower level of capacity value than they provide, thus, failing to achieve ratepayer indifference. Utility capacity costs are driven by the need to provide service reliability. The Company proposal would not result in equal reliability outcomes for a wind QF project as compared to a Company owned thermal resource. While it is very clear that a wind resource cannot provide the same capacity contribution as a thermal resource, the disparity is not as great as assumed by the Company.

Q. BRIEFLY DISCUSS THE PROBLEM WITH THE COMPANY'S APPROACH.

A. Figure 1 below illustrates the concern. The figure shows the actual availability of both wind and Company owned thermal resources during the 500 selected peak hours. Results are sorted from the best to worst single hours.

Were the Company to install a 100 MW thermal unit, it counts the entire 100 MW in its reserve margin calculations. In contrast, the Company would include only 4.1 MW of a 100 MW wind project in its reserve margin calculations. Figure 1 shows that over the five year period, PacifiCorp's thermal units have never been available 100% of the time. Instead, their best availability in a single peak hour was 99%, while the worst single hour during this period was 73%. Thus, the Company is proposing to treat wind resources using a different standard than it uses for thermal units, as is shown in Figure 1.



Q. HOW SHOULD THE ANALYSIS BE PERFORMED?

A. A more proper analysis should be based on equalizing the reliability impacts of thermal and wind resources. From a reliability perspective, it is not the average availability, or the 90th percentile that matters, but rather the availability in all hours and particularly during extreme conditions that matters the most. Consequently, I developed an analysis to determine the wind capacity contribution that would result in equal reliability between wind and Company owned thermal resources.

Q. PLEASE EXPLAIN YOUR ANALYSIS.

A. Planners recognize that reserves must be provided to meet extreme situations. Even though thermal units may have only an average of 5 to 10% for outage rates, higher reserve margins are provided to accommodate multiple unit outages, unexpected loads, and the like. The optimal level of reserves necessary is a complex subject and outside the scope of this case. At present reserve margins in the range of 12-16% are being studied by the Company in its IRP.

Specifying the level of reserves really implies the planner is seeking a specific level of reliability. In my analysis, I determined the level of reliability obtained from specific levels of the thermal reserve margin.[4] I then determined how much additional load could be served when wind is added to the system in order to obtain the same level of reliability.

Consequently, I tested a range of thermal reserves between 12 to 16%. Based on current levels of thermal capacity, I determined the amount of load that could be served with reserve margins between 12% and 16% using only thermal capacity. I then compared that to the actual thermal availabilities and determined the number of instances when additional resources (DSM, tie line support or short term purchases would be required.)[5] For example, were the Company to use a 16% reserve margin, it would have needed supplemental resources only [redacted] hours of the 500 peak hours (or about 4%) during the past five years. Based on the Company's currently installed [redacted] MW of thermal capacity, this equates to a load serving capability of about [redacted] MW. For any load level above [redacted] MW, the Company would have needed additional resources for [redacted] hours.

In other words, based on installed capacity of [redacted] MW, and a 16% reserve margin target the Company could serve [redacted] MW of load, but owing to thermal outage it would

4 This does not consider hydro, which would provide a constant amount of additional capacity, and would not alter the relative wind/thermal results.

5 This is a reliability metric used elsewhere in the country called DSCR – Dependence on Supplemental Capacity Resources. I have been involved in several cases involving this metric.

have still needed to obtain additional resources for [redacted] hours of the 500 peak period hours in the past five year.

Q. WHAT HAPPENS WHEN WIND CAPACITY IS INCLUDED?

A. Based on the actual availability of wind resources for the same 500 hours and the current wind capacity levels ([redacted] MW for the East Control Area) to obtain the same level of reliability ([redacted] hours or less of capacity shortfall) the Company could have served an additional [redacted] MW of load. This equates to 14.1%[6] of the nameplate wind capacity. This was determined by adding the actual hourly wind and thermal capacity available during the 500 hours, and then determining how many hours that additional resources would have been needed. The goal was to find, for each level of wind plus thermal capacity, the amount of load that would be served and how many hours additional resources would be needed to serve higher loads.

Q. IS THIS THE CAPACITY CONTRIBUTION YOU ARE RECOMMENDING?

A. Not quite. This example was premised on a single 16% reserve margin scenario. However, the Company may end up using a lower reserve margin which would provide different results. I examined 35 observations producing 12% to 16% thermal reserve margins. In order to be conservative, I selected the <u>minimum</u> capacity contribution, 13.8%, of the 35 observations. Given the greater variability of wind generation some conservatism is appropriate.[7]

Q. WHAT IS THE IMPACT OF YOUR RECOMMENDATION ON AVOIDED COSTS?

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[6] 172/1216 = 14.1%

[7] Use of the average contribution would not change the result much, increasing to 16.4%. This would have very little impact on the avoided costs.

A. Implementing this adjustment would increase avoided costs by $1.21/MWH for wind QFs based on the Company's current figures.

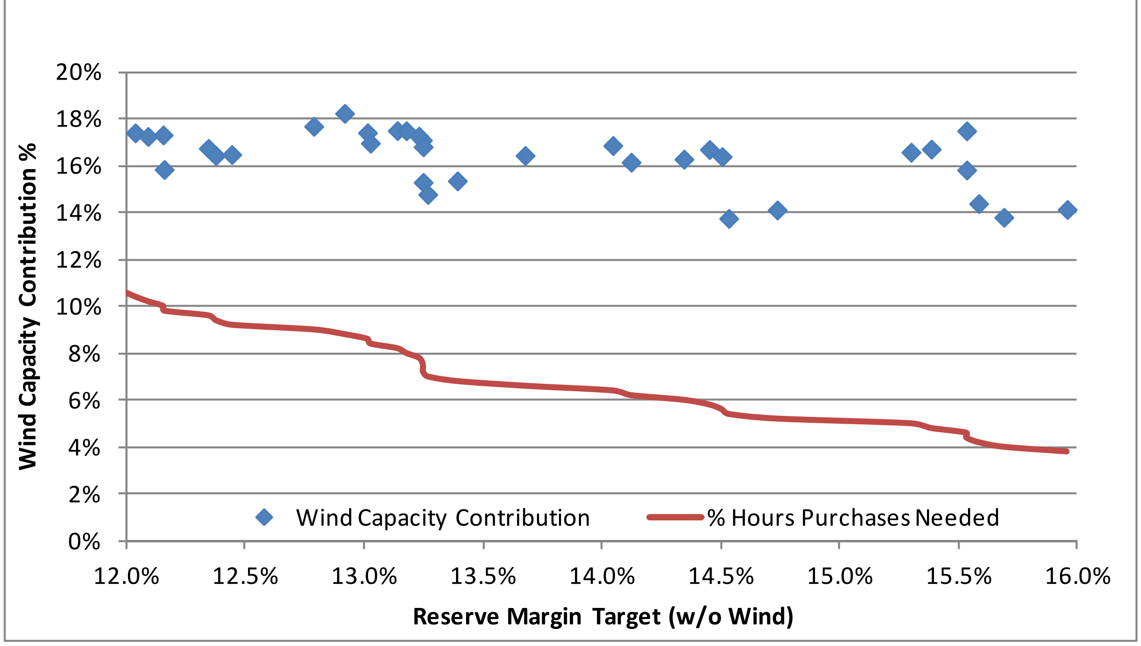
Q. DO YOU HAVE A FIGURE THAT SHOWS YOUR OVERALL RESULTS?

A. Yes. Figure 2 summarizes these results. The figure shows for each reserve margin target the percentage of the peak hours the Company would require additional resources (e.g. purchases) in order to serve load. The figure also shows for each thermal reserve margin target the wind capacity contribution that produces the same level of reliability. Under this approach, the reliability impact of wind is equalized with that of thermal. The actual capacity contribution falls in the range of 13.8% to 18.5%. As would be expected the less stringent the reliability target, the higher the capacity contribution of wind, as it implies the Company is less risk averse.

If the Company planned for a 16% reserve, the red line shows that for about 4% of the 500 peak hours, the Company would have required additional resources. To achieve the same level of reliability, the wind capacity contribution is about 14% as shown with the blue diamonds.

Were the Company to plan for a 12% reserve target, it would need additional resources more than 10% of the time, and under this relaxed reliability standard, it could count on a wind capacity contribution of close to 18%. As shown in Figure 2, there is a substantial amount of scatter in the data, but the final capacity contributions fall generally within a range of 14-18%.

Figure 2: Wind Capacity Contribution v. Thermal Reserve Target



Q. EXPLAIN WHY YOUR ANALYSIS WAS LIMITED TO EAST CONTROL AREA WIND RESOURCES.

A. Based on the data provided by the Company in OCS 2.2, it is apparent that West Control Area resources do not provide the same capacity value as East Control Area resources. The location and average capacity factors for wind resources influences the level of the capacity contribution. Because the Commission is setting prices for QFs located in Utah, ideally we would do an analysis based on Utah wind projects only. There is only one such project (Spanish Fork) so there is simply not enough data to make reasonable inferences. However, there are enough resources in the three Eastern states (Idaho, Wyoming and Utah) to do a reasonable analysis.

Q. DO YOU HAVE ANY FURTHER RECOMMENDATIONS RELATED TO THIS ISSUE?

A. There is no conceptual reason the Company could not perform its own analysis of this nature, using loss of load hours, or whatever reliability metric it prefers. In future updates, the Company should develop an analysis that treats the reliability of thermal and wind resources comparably.

Other Matters

Q. THE COMPANY DOES NOT INLCUDE ANY FUTURE RPS WIND RESOURCES IN THE GRID MODEL STUDY USED TO COMPUTE AVOIDED COSTS. IS THIS REASONABLE?

A. Yes. For the reasons discussed above, the future RPS resources should not be included for determination of Utah avoided costs. These resources are not part of the Utah least cost plan, may never be built and even if built, and the ultimate allocation of their associated costs and benefits is presently undecided.

IV. RECOMMENDATIONS

Q. PLEASE SUMMARIZE THE OFFICE'S RECOMMENDATIONS.

A. Our recommendations are below:

1. OCS recommends the Commission no longer require the Market Proxy method for determining wind QF avoided costs and instead use the PDDRR method.
2. OCS recommends the Commission require the Company to update its wind integration cost calculation after it has fully vetted the 2012 WIS in the IRP or an upcoming GRC.
3. OCS recommends the Commission use a 13.8% capacity contribution for wind resources, resulting in a $1.21/MWh increase in the Wind QF avoided cost rate.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes.