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BEFORE THE PUBLIC SERVICE COMMISSION OF UTAH

In the Matter of Review of Electric Service Schedule No. 38, Qualifying Facilities Procedures, and Other Related Procedural Issues	**DOCKET NO. 14-035-140** **Utah Clean Energy Exhibit 1.0 REDACTED**

DIRECT TESTIMONY OF KEN DRAGOON
ON BEHALF OF
UTAH CLEAN ENERGY

REDACTED

April 28, 2015

RESPECTFULLY SUBMITTED,
Utah Clean Energy

Sophie Hayes
Counsel for Utah Clean Energy

INTRODUCTION

Q: Please state your name and business address.

A: My name is Ken Dragoon. My business address is 3519 NE 15th Avenue, #227, Portland, Oregon 97212.

Q: By whom are you employed and in what capacity?

A: I am the Director and proprietor of Flink Energy Consulting LLC, a private consulting business whose mission is to advise a diverse clientele on matters relating to electric power planning and analysis, specializing in issues relating to renewable energy sources.

Q: On whose behalf are you testifying?

A: I am testifying on behalf of Utah Clean Energy (UCE).

Q: Please provide your professional experience and qualifications.

A: I am the Director and proprietor of Flink Energy Consulting LLC. I began Flink Energy in October 2014; however my career in the power industry is in its fourth decade, having started at the Bonneville Power Administration (BPA) in 1982. I worked at BPA in a number of capacities until 1996, ranging from power system planner and hydro modeling to risk management and runoff forecasting. After BPA, I worked for Pacificorp, also in a number of capacities that included contract pricing and structuring analysis, risk management, power system modeling, and renewable resource acquisitions. I performed PacifiCorp's first wind integration cost study for its 2003 IRP. After nine years at PacifiCorp, I spent four years at Renewable Northwest Project (now Renewable Northwest) as their Research Director, primarily working on wind integration and integration cost issues. I spent two years each at the Northwest Power and Conservation

Council and at Ecofys, a sustainable energy consulting firm headquartered in The Netherlands. I authored a book on wind integration cost methods in 2010[1] and was an invited coauthor to a second book on renewable energy integration published in 2014[2]. I have authored or coauthored a number of articles relating to renewable resource integration and capacity valuation methods, including two of the papers referenced in the Company's direct testimony of witness Rick Link, Exhibit RTL-2[3]. One of the papers was a survey of wind power capacity valuation methods[4]. I hold a master's degree in physics from the University of New Hampshire, 1982.

Q: Have you testified previously before this Commission?

A: No**.**

POSITION & RECOMMENDATIONS

Q: Please summarize your position in this matter.

A: PacifiCorp's results from their Capacity Factor Approximation Method (CFAM) analysis are significantly lower than the results presented in NREL's meta-study of capacity values and methods[5] as well as the results from a recent analysis reviewing the Western Electricity Coordinating Council's (WECC) Transmission Expansion Planning

[1] *Valuing Wind Energy on Integrated Power Systems*, Elsevier, September 2010
[2] *Renewable Energy Integration: Practical management of variability, uncertainty, and flexibility in power grids*, edited by Lawrence E. Jones, Academic Press, 2014.
[3] See references [2] and [20] on pages 28 and 29 respectively of RMP_(RTL-s): *Comparison of Capacity Value Methods for Photovoltaics in the Western United States*, NREL, 2012.
[4] *Capacity Value of Wind Power*, IEEE Transactions on Power Systems, May 2011, Keane, Milligan, et al.
[5] *Comparison of Capacity Value Methods for Photovoltaics in the Western United States*, NREL, 2012. This presentation shows capacity values for solar well above 40% in eight of ten analyses. The two exceptions were in Portland General Electric's system (~30%) and Toronto (~30-45%).

Policy Committee (TEPPC)[6]. Because of this, and because a model's results are only as good as the inputs and assumptions that are used in the modeling, I thoroughly examined the underlying inputs and assumptions used by PacifiCorp in their capacity contribution analysis in order to verify the validity of their results. My testimony addresses two major issues with PacifiCorp's inputs and assumptions, which significantly affect their calculated capacity values for wind and solar resources. My testimony does not include a review of the LOLP analysis that was a precursor to PacifiCorp's CFAM analysis. My silence on any component of the LOLP or CFAM analysis should not be construed as agreement with the Company's methods, assumptions or results.

The first issue has to do with applying the Capacity Factor methodology to the PacifiCorp system *as a whole* instead of focusing on the capacity contribution of East side resources to meeting East side loads. If PacifiCorp could freely transfer power across its system during peak demand periods, their analysis would not have been problematic on this point; however, PacifiCorp's system has practical transfer capability limitations at peak periods–to transfer resources from the East side to the West side. This suggests that no incremental east side resources, irrespective of their type or availability, would reduce West-side winter-time outages.

[6] Comparing Resource Adequacy Metrics (Conference paper preprint), Ibanez and Milligan, November 2014, NREL/CP-5D00-62847. The review found that TEPPC's assumed 60% capacity factor was applicable to the Arizona, New Mexico, and Nevada regions.

In other words, including West side winter time loss of load events in the calculation unfairly dilutes meaningful capacity contributions of additional East-side renewable resources. As I explain below, a more accurate estimate of the capacity value of resources built on the East side (i.e., in the Rocky Mountain Power service territory) would be to measure the ability of those incremental resources to reduce outages within the Rocky Mountain Power territory, not within the combined system.

The second issue relates to PacifiCorp's planned maintenance schedule assumptions, which are overly aggressive for [redacted] and place too much emphasis on renewable resource performance in that month, further diluting their effective capacity contribution values. The Company's maintenance schedule assumptions results in a disproportionate number of calculated loss of load events [redacted]—nearly [redacted] of the Company's annual loss of load events—due to a disproportionate amount of assumed thermal unit maintenance in that month ([redacted] planned maintenance outages than in any other month).

I recommend that PacifiCorp re-run the study to correct these two major shortcomings. My analysis, based on the Company's data and calculations, estimates that the result of correcting these shortcomings would have a very large effect on the capacity value of renewable resources. It would slightly increase the capacity value for wind and also increase the capacity value for solar to values that are more in line with the values found in other analysis of solar capacity values in the arid west and the values found in NREL's meta-analysis of different methods[7].

REVIEW OF PACIFICORP'S CAPACITY CONTRIBUTION STUDY

Q: Can you explain what the Capacity Factor Approximation Method is?

A: Yes. The capacity factor approximation method is one of several methods used to estimate the contribution of resources to meeting demand. Historically, when generation was comprised mainly or entirely of dispatchable resources, utilities would simply add up the nameplate capacities of their generating units and compare the total with peak demand. Given that generating units break down and need maintenance, and because peak demand is somewhat uncertain, utilities strove to maintain more generating capability than expected peak demand. Maintaining power system adequacy requires having more generating capability than expected demand by a buffer amount. This buffer amount is often termed the "Planning Reserve Margin."

Variable resources, such as wind and solar, have operating characteristics significantly different from conventional resources, so utilities recognized a need to calculate capacity contribution values that were more consistent with and comparable to the capacity contribution values of conventional resources in order to conduct accurate resource adequacy analysis. The Capacity Factor Approximation Method is one method of calculating equivalent capacity contribution figures for variable energy resources.

[7] ibid.

Q: Are you saying that methods to determine a capacity credit were devised to calculate the contribution of renewable energy resources for the purposes of computing resource adequacy?

A: Yes. One megawatt of wind or solar generator nameplate capacity is not the same as one megawatt of a conventional resource nameplate capacity when it comes to meeting peak demand. Some means of taking account of the fact that these resources do contribute to system adequacy, though in a lesser way than conventional resources, was deemed necessary. The key here is coming up with a method to find a capacity value for renewable resources that can make them consistently comparable to conventional generation resources in meeting the planning reserve margin.

Q: How does the Capacity Factor Approximation Method Work?

A: In effect, the capacity factor approximation method looks at the expected performance of variable resources at times when the utility would otherwise be short of energy to serve load. If the variable resources are expected to produce their maximum power capability at times when the utility would otherwise be short, they get a high credit. Conversely, if the utility is likely to be short at times when the resource is expected to produce very little power (e.g., solar power on winter nights), then the capacity credit is very low—potentially zero.

The capacity factor approximation method takes a weighted average of expected resource availability over hours that the utility is most likely to be short of meeting demand.

Weighting of resource availability is determined in relation to the likelihood that the power system will experience an outage in each hour of the year. Likelihood of outages is often determined, as the Company has done, by running a "stochastic" study in which a number of scenarios are examined. Each scenario consists of selections of loads and resource availability from some pre-determined probability distributions. In a reasonably adequate power system (one that has sufficient resources to meet demand under most circumstances), most hours will have zero outages. In only a few relatively extreme cases (e.g., high loads and high unit outages) will there be any outages.

As an example, assume that a study shows only two hours of the year where the utility was short. Say one of the hours is in the middle of the night when solar power is unavailable, and that the other hour happens to be in the middle of a summer day when the solar plant is expected to produce at 80% rated output. If the daytime outage is three times more likely to occur than the nighttime outage the Capacity Factor method would calculate the overall contribution as follows:

(Relative Likelihood in Hour 1) X (Resource Availability in Hour 1) +

(Relative Likelihood in Hour 2) X (Resource Availability in Hour 2) =

25% X 0% + 75% X 80% = 60%

Q: What assumptions are critical to this calculation?

A: There are two main components to the calculation—the weights established for each hour of the year, representing relative potential for shortfalls in meeting load, and the availability of resources in each of those hours. However, there is a less apparent assumption the Company makes that calls into question the appropriateness of their approach.

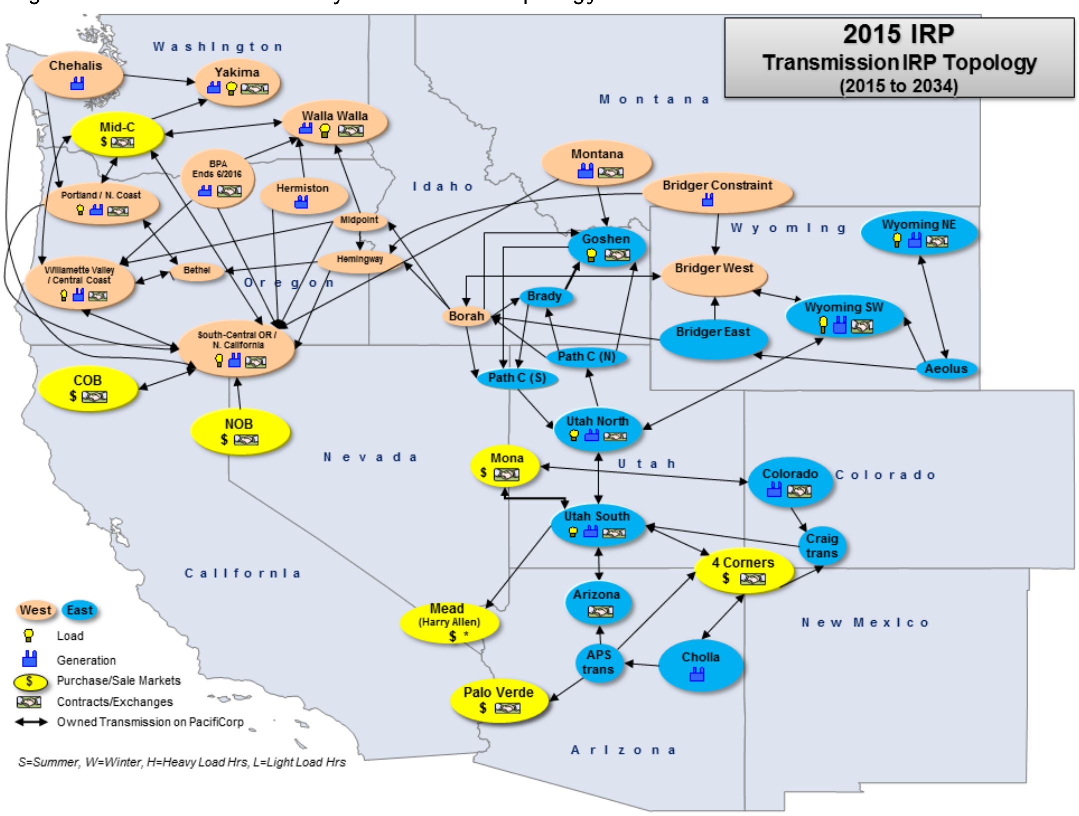
PacifiCorp's system is divided into a West-side balancing authority and an East-side balancing authority. The Company's application of the Capacity Factor Approximation Method implicitly treated the two sides of the system as though they were an integrated whole. This is in my view a critically important assumption because the Capacity Factor Approximation Method is not broadly applicable to systems with significant transmission constraints. It calls to question the validity of the results of PacifiCorp's analysis.

Q: Can you explain why applying the Capacity Factor Approximation Method to PacifiCorp's combined system is not appropriate?

A: The two sides of PacifiCorp's system are relatively loosely connected by its transmission system. Because loads on the East side of the system (Rocky Mountain Power) tend to peak in the summer, surplus resources on the West side fill the transmission lines heading east. Generally there is more generating capability in the East than is needed in the East during the winter because loads are lower there at that time of year than in the summer; however, the practical effect of limited transfer capability going from east to west in the winter means that not all of those East-side resources are able to contribute to meeting West-side load.

What this suggests is that *incremental* resources on the Rocky Mountain Power side of the system cannot affect resource adequacy in the West during the winter, just as resource additions on the West side can't help meet Rocky Mountain Power's summer peak demand. The figure below from PacifiCorp's 2015 IRP shows the two transmission paths across southern Idaho (Borah to Midpoint and Borah to Hemingway) that limit PacifiCorp's East-West access[8].

Figure 7.2 – Transmission System Model Topology



In effect, including West-side winter outages in the Capacity Factor Approximation Method computation incorrectly values the actual contribution of East-side renewable resources compared with East-side conventional resources—the original purpose of the

[8] In the Company's response Confidential Attachment OCS 3.10-2 the Combined Borah Midpoint and Hemingway transfer capability [redacted]

Capacity Factor Approximation Method. RMP's Capacity Factor Calculation workbook shows that [redacted] of all loss of load events occurring in the study happened in the December through February period, when it is unlikely that any type of resource addition on the East side would materially affect loads on the West side due to full transmission capacity going from east to west.

Example:

> Assume that a system consists of an East and West side that are connected by a 1,000 MW transmission line that allows power to flow in both directions. Say that the West side peaks in the winter time when the East side has 1,500 MW of surplus power—generating capability in excess of what is needed in the East in that hour. During a peak hour in the West, once 1,000 MWs of power fill the transmission capability from east to west, the remaining East side resources can no longer provide assistance. If the West is still short, adding another power plant in the East only has the effect of making the East more surplus. It is this situation that makes PacifiCorp's broad application of the capacity factor approximation method misleading.

The purpose of developing a capacity contribution method is to assess the contribution of variable resources *relative to conventional generation*. Conventional generation located on the west side would not significantly contribute to meeting West-side loads because of the transmission constraints. A fair capacity valuation method seeks to set an equivalency between variable and conventional resources. Basing the calculations on PacifiCorp's entire system effectively compares variable resources to an impossible conventional resource located simultaneously on both sides of PacifiCorp's system. The effect is most prominent for solar resources, substantially understating them on the East side of the system and overstating their capacity contribution to the West side. ***If there is transmission congestion during peak demand hours, new conventional generation located on the East side can't contribute to West side winter demand any more than the solar plants.***

Q: Are you certain that PacifiCorp's system is transmission-constrained during winter time loss of load events?

A: I was not able to completely corroborate that conclusion from the available data yet[9], but this has been a long-standing issue with the Company I am aware of from the time that I worked there.

Q: Did you examine data supplied by the company that addresses this concern?

A: Yes, although the transmission loadings are not yet available, I looked at the Company's response to DR OCS 3.10 ("Attachment OCS 3.10-3"). That set of Excel workbooks purports to contain energy not served for each area in the model, in each hour, for each iteration.

[9] UCE submitted the following data request to PacifiCorp, for which we are awaiting a response: "Please provide transmission path loadings over each of the loss of load event hours."

My expectation was to see west side outages dominating in winter, and east side outages dominating in summer, with a separate significant grouping [redacted] due to the maintenance effects previously discussed. However, the data was not as expected. The most obvious anomaly was with the Colorado. There were more than 20,000 counts of energy not served there, in contrast to just over a thousand in the reset of the areas combined. These values are not consistent either in number or timing with the Company's initial filing.

Discounting the anomalous Colorado numbers left just over 1,000 loss of load events. Although there was a large percentage of them in April, the winter loss of load events are shown occurring in Wyoming on the East side. It is unclear whether this finding, if I am reading their data correctly, is reasonable. For example, if these loss of load events are associated with assumptions around weather-driven uncertainties applicable to the energy sector generally, they may not be applicable to the Wyoming area which consists primarily of industrial loads of the oil and gas development sector.

We will need additional information from the Company to reconcile their response in Attachment OCS 3.10-3 with their other analysis to fully understand their calculations.

Q: Given the limited east to west transfer capabilities, did you calculate how the capacity value for solar would change if the capacity value was calculated based on an East-side solar project providing electricity to the East side of the PacifiCorp system?

A: I was not able to do a complete analysis, but I was able to observe the effect of removing winter month outages from the computation. This represents a rough approximation of the effects of running an East-side only study under the assumptions that winter-time loss of load events occurred on the West side at times of transmission congestion.

Q: What is the effect on capacity contributions from removing winter-time loss of load events from RMP's calculation?

A: The effect was greatest on Utah solar capacity values, increasing Milford Solar Fixed and Single Axis Tracking in the range of 10 to 13 percentage points to 44.4% and 52%, respectively. Below is a table of the full results.

Results from RMP Capacity Factor Calculation Workbook as submitted:

	Wind			Solar PV					
	West	East	Weighted Average	Lakeview, OR Fixed Tilt	Milford, UT Fixed Tilt	Average Fixed Tilt	Lakeview, OR Single Axis Tracking	Milford, UT Single Axis Tracking	Average Single Axis Tracking
Peak Capacity Contribution (PacifiCorp)	25.4%	14.5%	**18.1%**	32.2%	34.1%	**33.1%**	36.7%	39.1%	**37.9%**
Interim Capacity Contribution (Utah Commission)			20.5%			**68.0%**			**84.0%**

Results from RMP Capacity Factor Calculation Workbook, after removing [redacted] loss of load events:

	Wind			Solar PV					
	West	East	Weighted Average	Lakeview, OR Fixed Tilt	Milford, UT Fixed Tilt	Average Fixed Tilt	Lakeview, OR Single Axis Tracking	Milford, UT Single Axis Tracking	Average Single Axis Tracking
Peak Capacity Contribution (PacifiCorp)		16.4%			44.4%			52.0%	
Interim Capacity Contribution (Utah Commission)			20.5%			**68.0%**			**84.0%**

Q: Please explain your methods and findings.

A: The values computed above were derived by simply setting all loss of load events to zero in the Company's workbook in the December through February period ("Hourly LOLP" worksheet, cells B3:Y61, B337:Y367). The workbook automatically recomputed the values above, found on the "Summary" worksheet in cells B1:K4. The result is an increase in solar capacity credit to 44.4% for fixed tilt and 52% for single axis tracking solar.

Q: What do you conclude from your analysis?

A: The analysis suggests that the Capacity Factor Approximation Method is extremely sensitive to the assumptions used in the model and that consideration of the balancing area that resources serve is critical in accurately calculating the capacity value. Solar resources are very effective in meeting east side loads, providing much more capacity value relative to conventional resources than they are at providing winter capacity needs on the west side. If transmission is congested during peak demand periods, solar provides much more value than the present study suggests. Transmission congestion becomes a key question. The Company's application of the Capacity Factor Approximation system is not accurate when there are significant transmission limitations.

East side resource capacity contribution should be evaluated relative to east side conventional generation. That means *excluding* West side loss of load events from the calculation that occur at the same time transmission is constrained. In my opinion, it is inclusion of the West side loss of load events that accounts primarily for the Company's method arriving at numbers far lower than other calculations of this nature. To accurately characterize the capacity value of East-side renewable energy resources, the capacity value should be calculated based on the East side balancing area.

Q: If there were unlimited transfer capability between the East and West side of the system, how might this change the capacity value of solar on the East side of the system?

A: That would be an interesting study, but I can't easily estimate what the effects would be, because it would require rerunning the LOLP study with unlimited transfer capabilities. The model would find fewer loss of load events, and it might be necessary to run more than 500 iterations in order to get reliable LOLP statistics. How it affects a summer peaking resource like solar depends on whether the majority of loss of load events occur on the west side in the winter, or the east side in summer. The latter would tend to increase the capacity value of solar, whereas the former would reduce it. That said, unless there actually are unlimited transfer capabilities, the analysis would give results for loss of load probability and capacity value that do not reflect PacifiCorp's actual circumstances.

Q: Are there other issues with study assumptions?

A: There are a few other technical issues, but the one that has the largest effect after the combined-system assumption above, is the undue effect of assumed maintenance schedules on the results. Certain loss of load events in the Company's study are an artifact of the company's overly-aggressive assumptions about the level of maintenance outages [redacted].

Q: How do maintenance schedules affect the results?

A: Maintenance schedules are periods of time when generators are intentionally taken out of service for routine or special maintenance needs. If at all possible, generators are only taken out of service at times of the year when they are least needed (and loss of load probability is lowest), and when market prices (e.g., for purchasing replacement power) are lowest. From the Company's data request responses in OCS 2.3 and 2.7, it is apparent that the maintenance schedules followed the usual pattern, concentrating maintenance outages in [redacted]; three of the four lowest peak demand months (a smaller amount of maintenance is also scheduled in [redacted]). Scheduling maintenance in that way is designed to minimize potential shortfalls in the ability to meet load.

However, there can also be too much of a good thing. If too much maintenance is scheduled in a single month, it can result in additional loss of load events. In other words, maintenance outages are normally set to have no effect on the ability to meet load, but it can result in additional loss of load if too many generators are taken out of service at a given time. In this case, it appears that PacifiCorp could have avoided loss of load events by moving [redacted] (which I discuss further below).

Q: How did the Company's assumed maintenance schedule affect the results of their study?

A: Again, according to OCS 2.7, the company used an assumed maintenance schedule with a disproportionate amount of outages in [redacted]. The effect of this is fairly dramatic. Again from the Company's Capacity Factor Calculation workbook, almost [redacted]. In contrast, even though the Company's loads are [redacted] of loss of load events in that month. Moving just a [redacted]. Ideally, maintenance schedules should be informed by LOLP studies to minimize the potential for loss of load.

The issue with this is that the loss of load events [redacted] affected the capacity contribution calculation. In fact, NREL's study on which the Company's analysis is based[10] suggests excluding all but the highest load hours in the application of the Capacity Factor Approximation Method in order to avoid such anomalous results. Moreover, the loss of load events are entirely an artifact of assuming too much maintenance [redacted]. If some [redacted]

[10] See attachment Rick Link's testimony Exhibit RMP (RTL-2) page 6: "A third technique uses the highest-load hours but normalizes the capacity factors by the LOLPs." RMP appears to have used this method in normalizing LOLPs, but not applying them only to the "highest-Load" hours. The Company's April loads are not particularly high and presumably would have been excluded in a literal application of the method.

[redacted]. There is no necessity for loading so much maintenance [redacted], and clearly doing so at the expense of maintaining system reliability is not something the Company would actually do if it could possibly help it. I am not suggesting any changes to actual maintenance schedules—schedules that will not be prepared for years to come—only the model assumption that so much of the needed maintenance will occur [redacted].

The potential for maintenance schedule assumptions can be critical. For example, if all the maintenance were scheduled for January and February, solar resources would have nearly zero capacity value in the computation. If scheduled in June and July, the capacity value would soar to near 100%. The maintenance schedules need to be carefully considered.

Q: Can the Company change maintenance schedules as easily as you imply?

A: There are typically constraints on when maintenance can occur. It can be affected by equipment warranties, availability of crews and equipment to perform maintenance, and immediacy of the need for maintenance. That said, the study's maintenance schedules are simply placeholders for what might be expected to occur many years from now during the resource insufficiency period. In other words, there is plenty of time to adjust the schedule if that were advisable. In this case, the Company simply appears to have made an assumption about the schedule that was a little too aggressive. Moving just a few hundred megawatts of maintenance from [redacted].

Q: Why do you recommend March?

A: The study had zero maintenance [redacted] having the fourth lowest peak load. Given that the [redacted] than any other month, it is reasonable and appropriate to move some of these maintenance outage megawatts [redacted].

And again, I am not recommending that the Company make any changes to its actual maintenance schedules. The study's maintenance schedules are merely placeholders for maintenance schedules many years down the road in the resource insufficiency period. It is reasonable to assume that a few hundred megawatts of maintenance can and will be moved [redacted], rather than assuming such extreme levels of maintenance outages [redacted].

Q. Can you estimate the impact of a more moderate maintenance schedule?

A. I was able to see the effect of removing the [redacted] loss of load events on the capacity credit calculations. The table below illustrates the findings.

Results from RMP Capacity Factor Calculation Workbook as submitted:

	Wind			Solar PV					
	West	East	Weighted Average	Lakeview, OR Fixed Tilt	Milford, UT Fixed Tilt	Average Fixed Tilt	Lakeview, OR Single Axis Tracking	Milford, UT Single Axis Tracking	Average Single Axis Tracking
Peak Capacity Contribution (PacifiCorp)	25.4%	14.5%	**18.1%**	32.2%	34.1%	**33.1%**	36.7%	39.1%	**37.9%**
Interim Capacity Contribution (Utah Commission)			20.5%			**68.0%**			**84.0%**

Results from removing April loss of load events:

	Wind			Solar PV					
	West	East	Weighted Average	Lakeview, OR Fixed Tilt	Milford, UT Fixed Tilt	Average Fixed Tilt	Lakeview, OR Single Axis Tracking	Milford, UT Single Axis Tracking	Average Single Axis Tracking
Peak Capacity Contribution (PacifiCorp)		13.1%			37.0%			40.2%	
Interim Capacity Contribution (Utah Commission)			20.5%			**68.0%**			**84.0%**

Q. Given that you recommend that both of these modeling assumptions should be corrected to fairly calculate the capacity value of renewable resources, did you examine the combined effects of a more moderate maintenance schedule and calculating capacity credit based on an East side examination?

A. Yes, I did. The combined effects are shown in comparison to PacifiCorp's findings in the pair of tables below:

Results from RMP Capacity Factor Calculation Workbook as submitted:

	Wind			Solar PV					
	West	East	Weighted Average	Lakeview, OR Fixed Tilt	Milford, UT Fixed Tilt	Average Fixed Tilt	Lakeview, OR Single Axis Tracking	Milford, UT Single Axis Tracking	Average Single Axis Tracking
Peak Capacity Contribution (PacifiCorp)	25.4%	14.5%	**18.1%**	32.2%	34.1%	**33.1%**	36.7%	39.1%	**37.9%**
Interim Capacity Contribution (Utah Commission)			20.5%			**68.0%**			**84.0%**

Results from removing [redacted] and [redacted] loss of load events:

	Wind			Solar PV					
	West	East	Weighted Average	Lakeview, OR Fixed Tilt	Milford, UT Fixed Tilt	Average Fixed Tilt	Lakeview, OR Single Axis Tracking	Milford, UT Single Axis Tracking	Average Single Axis Tracking
Peak Capacity Contribution (PacifiCorp)		15.3%			67.0%			73.4%	
Interim Capacity Contribution (Utah Commission)			20.5%			**68.0%**			**84.0%**

These results are more aligned with other reported capacity value analyses.

Q: Can you summarize the changes you recommend?

A: Yes. The company should either re-run the analysis with an East side scope or else demonstrate that loss of load events during the winter time are not coincident in time with transmission congestion. The Company should also either re-run the study with 200-400 MW of maintenance moved from [redacted] to some other month ([redacted] is a good candidate). Failing that, the weights for [redacted] ought to be excluded, either because it is likely that a revised maintenance schedule would have that result or because their inclusion is inconsistent with the NREL method, or both.

If winter loss of load events in Wyoming dominate wintertime loss of load, we need to better understand the assumptions that resulted in the events and determine the underlying causes and the applicability to the Capacity Factor Approximation Method.

CONCLUSION

Q: Please summarize your conclusions and recommendations.

A: I conclude that the Company's study finds a much lower capacity credit for renewable resources than other such studies for two main reasons:

1) It dilutes the capacity value of solar by averaging its contribution across PacifiCorp's system—this would make sense *but for* the fact that there is

insufficient transmission from east to west to make the capacity credit a sensible comparison to conventional resources.

2) The Company's study assumed too much maintenance in [redacted], which ends up overstating the effect of renewable resource availability in the spring.
3) In the loss of load analysis for the Capacity Factor Approximation Method assumptions around load uncertainty need to be revisited.

The Company can remedy these issues by re-running the analysis including only East side loss of load events, and moving some maintenance schedules from [redacted] [redacted]. The practical effect of these changes would be to diminish or eliminate the weights established in the present study in [redacted] and the winter months, resulting in a capacity credit that more accurately reflects wind and solar capacity values.

OTHER ISSUES

Q: Do you have any other comments on the study?

A: Yes, one other issue bears mentioning. The Company used TMY data, or "Typical Meteorological Year" data to produce its solar generation profiles. These profiles are publicly available data sets based on historically "typical" weather, which are not time correlated to the meteorological data underlying the Company's load forecasts. Ultimately, this produces incorrect results.

Evaluations of capacity contribution, for example, for solar resources, such as those based on LOLP, should be based on solar data that is time correlated with load rather than based on "typical meteorological year" (TMY) data. If load is simulated based on assumed temperatures, then the underlying meteorological data set should be the same for both the solar profile and the load. For example, the underlying data might include solar irradiance, temperature, and wind speed. In any given simulation hour, the same data should be used to simulate solar production and simulate load. If load and solar output are based on meteorological conditions for different times (such as taking "typical" data from different years), then the relationship between solar production and load is lost and the evaluation method will miss an important effect.

While I think this represents a significant issue, solutions to it remain relatively scarce at this point. I raise it because it should be monitored and remedied going forward.

Q: Does that conclude your testimony?

A: Yes.