BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

UM 1719

In the Matter of	)
	)
PUBLIC UTILITY COMMISSION OF OREGON	)
	)
Investigation to Explore Issues Related to a Renewable Generator's Contribution to Capacity	)

OPENING TESTIMONY

OF THE

CITIZENS' UTILITY BOARD OF OREGON

December 14, 2015

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

UM 1719

In the Matter of PUBLIC UTILITY COMMISSION OF OREGON Investigation to Explore Issues Related to a Renewable Generator's Contribution to Capacity	OPENING TESTIMONY OF THE CITIZENS' UTILITY BOARD OF OREGON

My name is Nadine Hanhan, and my qualifications are listed in CUB Exhibit 101.

I. Introduction

The Oregon Public Utility Commission (OPUC) has opened an investigatory docket to explore renewable generation's contribution to peak capacity (CTP). CTP, as defined by Oregon Public Utility Commission Staff (Staff), is "a measure of the most likely amount of capacity (megawatts) the resource can deliver at the exact time of the utility's annual peak load."[1]

Staff explains that any estimate of CTP "will necessarily be inexact"[2] due to renewables' intermittency and variability, and hence historical data will not necessarily predict future years' generation. In light of this challenge, the Commission enlisted three experts in an August 17, 2015 workshop—Michael Milligan, Andrew Mills, and John Fazio—to present their analysis on

[1] Order No. 15-077, Appendix A, p. 2.
[2] Ibid.

several methodologies used to calculate CTP. The experts offered a number of different methods to approach measuring renewable contribution during high-risk hours, and in addition to the experts' analysis, the Commission has requested that stakeholders address CTP methodology. In order 15-077, the Commission adopted the following Staff Identified Issues:

> • At present each utility is left to make its own determination of CTP. This could be seen as unfair treatment of independent renewable power producers (IPPs) under a standard PURPA QF contract among the three utilities - some parties will gain and some lose simply based on the CTP calculation method chosen. The relative risks and benefits of a standardized method of calculation should be explored.
>
> • The various approaches currently used by Oregon utilities to determine CTP have not been compared to each other and analyzed for accuracy and precision. The methodologies should also be compared to those methods utilized by utilities outside of Oregon to compare accuracy and precision.
>
> • It is expected that CTP will vary over time as the number of renewables on the system changes. The question of how often and on what schedule CTP determinations should be filed should be investigated.[3]

In addition, the Commission later asked parties to address the following matters in testimony:

1. The preferred methodology to calculate a renewable generator's contribution to capacity; and
2. The pros and cons of:
   a. Using an Effective Load Carrying Capability (ELCC) calculation;
   b. Requiring an alternative or approximation method to be benchmarked against and ELCC calculation; and
   c. Requiring the utilities to use the same calculation method. [4]

For the remainder of the testimony, CUB will provide its view on CTP based on what the Commission has outlined.

---

[3] Order No. 15-077, Appendix A, p. 5.
[4] UM 1719. Memorandum and Notice of Prehearing Conference. Accessed at http://edocs.puc.state.or.us/efdocs/HDA/um1719hda162837.pdf.

II. Pros and Cons of ELCC and Alternative Approximations

In the memorandum issued by the Oregon PUC on August 25, 2015, parties were asked to address the pros and cons of the effective load carrying capability (ELCC) methodology as an approach to measuring renewables' contribution to capacity. Generally, ELCC is a metric that estimates a resource's general contribution to capacity, whereas Staff had initially identified the subject of this docket to be contribution to *peak* capacity (or CTP) in its Staff report.[5] When referring to contribution to peak capacity, CUB will use "CTP," and when referring to contribution to general capacity, CUB will use "contribution to capacity."

As CUB understands it, ELCC is a metric that determines the value that an individual generator (or group of generators) adds to system adequacy. It can also be thought of (and is calculated) as additional load that can be met as a result of adding new generation while maintaining the same level of system adequacy. [6,7] ELCC analysis requires the selection of some reliability metric first, such as the loss of load expectation (LOLE),[8] and sometimes some benchmark generation unit. This can be either a conventional generator or a "perfect generator."[9] Once a reliability target is chosen on which to evaluate ELCC, the methodology can take several approaches. The California Public Utilities Commission (CPUC) identifies three different methods:

---

[5] See Order No. 15-077.
[6] Keane A.. Milligan M., et. al. Capacity Value of Wind Power. *IEEE Transactions on Power Systems*. (n.d.) Accessed at http://www.nerc.com/docs/pc/ivgtf/ieee-capacity-value-task-force-confidential%20(2).pdf.
[7] Methods to Model and Calculate Capacity Contributions of Variable Generation for Resource Adequacy Planning. NREL. March 2011. Accessed http://www.nerc.com/files/ivgtf1-2.pdf.
[8] LOLE is the expected number of days in a year that could meet generation outages. All of the literature CUB has seen uses 1 day/10 years, or .1 day/year as the LOLE benchmark.
[9] The CPUC defined "perfect generator" as one having "no transmission constraints, immediate start-up and shut-down, infinite ramping capability, no use limitations, and no outages." See http://www.cpuc.ca.gov/NR/rdonlyres/D05609D5-DE35-4BEE-8C9A-B1170D6E3EFD/0/R1110023ELCCandQCMethodologyforWindandSolar.pdf.

1. Modeling reliability with and without a given resource type, and determining how much load can be increased such that it cancels out the reliability improvement of including the resource.

2. Comparing the reliability impact of including the resource type to the reliability impact of including a conventional resource with assumed operating and outage characteristics.

3. Comparing the reliability impact of including the resource type to the reliability impact of including an idealized, "perfect generator."[10]

In general, the idea is to model the system with and without the renewable generation in question (say, X) and compare how much extra capacity X contributes while still maintaining the same level of LOLE (or other reliability metric). The actual system can be modeled first, X is then removed, and the system model is rerun to estimate the new LOLE. If the reliability target (LOLE) is not met as a result of removing X, then incremental capacity (either through the perfect generator or conventional generation) is added to the system and the model is rerun until the target LOLE is reached. This methodology can and has varied, but the basic idea is to compare the system with and without X against the same LOLE.[11,12]

The CPUC defines ELCC as a derating factor that is multiplied by a resource's nameplate capacity:

$$QC = ELCC\ (\%) * P_{max}\ (MW)$$

[10] These three definitions are taken directly from a CPUC Proposal. Effective Load Carrying Capacity and Qualifying Capacity Calculation Methodology for Wind and Solar Resources. California Public Utility Commission. January 16 2014. Accessed at http://www.cpuc.ca.gov/NR/rdonlyres/D05609D5-DE35-4BEE-8C9A-B1170D6E3EFD/0/R1110023ELCCandQCMethodologyforWindandSolar.pdf.

[11] Milligan, M. & Porter, K. Determining the Capacity Value of Wind: An Updated Survey of Methods and Implementation. NREL. (2008) Accessed at http://www.nrel.gov/docs/fy08osti/43433.pdf.

[12] Effective Load Carrying Capacity and Qualifying Capacity Calculation Methodology for Wind and Solar Resources. California Public Utility Commission. January 16 2014. p. 2. Accessed at http://www.cpuc.ca.gov/NR/rdonlyres/D05609D5-DE35-4BEE-8C9A-B1170D6E3EFD/0/R1110023ELCCandQCMethodologyforWindandSolar.pdf.

Where QC is the qualifying capacity[13] and P_{max} is the nameplate capacity.[14]

ELCC is thus used to inform the contribution of an individual generator, or group of generators, to an electric system's needs. This is not CTP, because the contribution of X is calculated at more than just the peak. This is a benefit of this methodology, as CUB will explain in more detail below. The process might also catch whether a renewable generator contributes to capacity at all, which would address utility concerns about peak contribution. Theoretically, it might be possible to see LOLE rise as a result of removing renewable generation X. This would flag potential reliability risks of adding a resource and bypass CUB's concerns with focusing on peak hours since the ELCC metric incorporates a system-wide approach.

For purposes of historical relevance in Oregon, CUB will compare how Oregon utilities have estimated contribution to capacity and CTP in their most recent IRPs and how they compare to an ELCC method of calculating renewable generation contribution to capacity.

PGE

In its 2013 IRP, PGE assigned a contribution to capacity estimation of 5%.[15] This was based on a range of hourly capacity factors for the top 5, 25, and 100 load hours of 2011 and 2012.[16] PGE states in its IRP that it calculated capacity factors on an hourly basis, presumably

[13] CPUC defines QC as "the number of Megawatts eligible to be counted towards meeting a load serving entity's (LSE's) System and Local Resource Adequacy (RA) requirements, subject to deliverability constraints." This is effectively the contribution to capacity.

[14] Effective Load Carrying Capacity and Qualifying Capacity Calculation Methodology for Wind and Solar Resources. California Public Utility Commission. January 16 2014. p. 2. Accessed at http://www.cpuc.ca.gov/NR/rdonlyres/D05609D5-DE35-4BEE-8C9A-B1170D6E3EFD/0/R1110023ELCCandQCMethodologyforWindandSolar.pdf.

[15] LC 56 – PGE IRP, p. 174-176.

[16] *Ibid*.

for every hour of the year, and chose the hours with the highest capacity demand using data from Biglow Canyon.[17,18] Below is the chart for PGE's range of CTP values:

Figure 1 – PGE CTP Values[19]

2011 and 2012 top load hours: median and 90th percentile CF

Top Hours	Median CF			90th Percentile CF		
	2011	2012	Average	2011	2012	Average
5	5.05%	1.40%	3.22%	0.00%	0.42%	0.21%
25	0.11%	10.67%	5.39%	0.00%	1.09%	0.55%
100	1.30%	15.39%	8.34%	0.00%	0.39%	0.19%

PGE ultimately chose to use the median CF, or a 50% exceedance level, to estimate a value for CTP.[20] As *Figure 1* demonstrates, the CTP ranges from 0 to over 15% depending on the assumptions, but PGE essentially chooses an average of averages at 5%.[21] PGE attributes this to the difficulty of "select[ing] a single point for the capacity contribution based on two years of data."[22]

Among the "pros" of this approach is that it is a relatively simple method of estimating contribution to capacity, and it is based on actuals. It arguably also has a tendency to produce conservative values because it uses the top 100 peak hours and no more. From a utility's perspective, this decreases the risk of threatening reliability due to the intermittency of renewable power. However, this conservative approach can also be seen (and CUB sees it as) more of a "con" than a "pro." Though this measures contribution to peak, this method does not account for other hours of the year in which renewables might generate power but that are not among the top

[17] At the time of the 2013 IRP filing, PGE's other wind farm, Tucannon had not yet come online.
[18] LC 56 – PGE IRP, p. 174-176.
[19] LC 56 – PGE IRP, p. 176.
[20] *Ibid*.
[21] (3.22%+5.39%+8.34%)/3=5.65%, which is higher than the selected CTP value of 5%.
[22] LC 56 – PGE IRP, p. 176.

100 hours. There may also be times of the year in which renewables generate power that contribute to system adequacy, but are not reflected in these hours because though they are higher risk, they are also not among the top 100—such as during planned maintenance.[23]

PGE pledges in its 2013 IRP to use data from the Tucannon wind farm when it is available, but using historical data has its own pros and cons—specifically, although it is useful and necessary to incorporate the historical generation profile of a wind resource for informational purposes, the future does not always reflect the past. In contrast, PacifiCorp uses more of a simulation approach in its 2015 IRP, which CUB discusses below.

Despite the fact that PGE has calculated this CTP value for wind, it does not include a CTP figure for solar generation anywhere in its 2013 IRP, though a recent QF document reveals that PGE assumes a solar contribution to capacity value of 5%,[24] and PGE also uses 5% in its 2013 IRP Update.[25] The methodology used to calculate this value is not explained in either document. However, even though PGE does not explain its solar methodology in its official IRP filing, PGE did present an analysis of solar capacity contribution in an IRP meeting on August 29, 2013.[26] In this analysis, PGE estimated the capacity contribution via two different methods—the same one it used for the wind study (i.e., taking the top 100 load hours and data from its 5

---

[23] Keane A.. Milligan M., et. al. Capacity Value of Wind Power. *IEEE Transactions on Power Systems*. (n.d.) Accessed at http://www.nerc.com/docs/pc/ivgtf/ieee-capacity-value-task-force-confidential%20(2).pdf.

[24] Schedule 201, Qualifying Facility 10 MW or Less Avoided Cost Power Purchase Information. Portland General Electric Company. 2015. Accessed at https://www.portlandgeneral.com/renewables_efficiency/generate_power/business/docs/sched_201.pdf.

[25] LC 56 – PGE IRP Update. p. 24.

[26] PGE 2013 IRP – 3rd Stakeholder Presentation and Discussion. August 29, 2013. pp. 57-68. Accessed at https://www.portlandgeneral.com/our_company/energy_strategy/resource_planning/docs/august2013_stakeholder.pdf.

MW Christmas Valley solar plant and applying a similar methodology).[27] PGE also separated the generating profiles by region and season:[28]

Figure 2 – PGE's Winter and Summer CTP Values[29]

Hours	Capacity Value
Top 100	7.6%
Top 100 winter	2.5%
Top 100 summer	54.3%
Top 50	6.3%
Top 50 winter	2.4%
Top 50 summer	55.8%

As *Figure 2* demonstrates, the variation in solar CTP varies even more widely than it did with wind. However, PGE chose to focus on the winter peaking hours, arguing that "PGE is a winter load peaking utility where highest demand hours occur in winter evenings when solar generation is absent,"[30] and "[i]t is prudent to look at the capacity contribution of a solar PV plant in the winter (i.e., the most constrained case) and to apply that result in our planning for resource needs in the future."[31]

In the same presentation, PGE presented an analysis of ELCC, where it ran a loss of load

[27] *Ibid*.
[28] *Ibid*.
[29] PGE 2013 IRP – 3rd Stakeholder Presentation and Discussion. August 29, 2013. p. 61. Accessed at https://www.portlandgeneral.com/our_company/energy_strategy/resource_planning/docs/august2013_stakeholder.pdf.
[30] PGE 2013 IRP – 3rd Stakeholder Presentation and Discussion. August 29, 2013. p. 64. Accessed at https://www.portlandgeneral.com/our_company/energy_strategy/resource_planning/docs/august2013_stakeholder.pdf.
[31] *Ibid*.

probability (LOLP)[32] study on a reference case without the solar resource to calculate unserved energy. PGE then added 20 MW (not 5) of solar capacity and recalculated the unserved energy with the addition of the solar system. By adding increments of additional load, PGE was able to calculate how well the solar resource was able to meet the additional load while retaining the same level of liability. This value was 3.8MWa of load, and yielded a capacity contribution of 19%, but PGE chose to retain the 5% value calculated with the previous winter "peak hour" approach.[33]

Some of the cons of this approach, as cited by PGE, are that the ELCC method "does not adequately address reliability during system peak loads,"[34] because the calculation is effectively a cumulative approach to overall system capacity, and not just during peak hours. In addition, PGE states that this method does not capture events where solar generation is low during peak hours.[35] PGE's main concern with this method seems to revolve around reliability concerns, which is understandable, and if this docket is meant to specifically determine *peak* contribution methodology, then focusing on peak hours is more appropriate. However, it is CUB's opinion that focusing on peak contribution ultimately runs the risk of undervaluing renewable energy contribution, thereby leading to a system that is overbuilt and at a potentially high cost to customers.

Given the range of values calculated by PGE, CUB believes that 5% is too conservative a number and runs the risk of an overbuilt system. CUB believes one of the merits of the ELCC approach is that it considers system-wide contribution of a single resource, or group of resources,

---

[32] LOLP is defined as "the probability of a loss of load event in which the system load is greater than available generating capacity during a given time period. LOLP is typically computed in one-hour increments." From http://www.nrel.gov/docs/fy12osti/54704.pdf.

[33] PGE 2013 IRP – 3rd Stakeholder Presentation and Discussion. August 29, 2013. p. 65-68. Accessed at https://www.portlandgeneral.com/our_company/energy_strategy/resource_planning/docs/2013_irp.pdf.

[34] *Ibid*.

[35] *Ibid*.

and is likely a more accurate reflection of reality. CUB understands the reliability concerns, and this is where Staff's suggestion of a benchmark against ELCC may come in handy. CUB would not be opposed to multiple contribution to capacity measurements as PGE has already done, but CUB is more concerned with the selection of the actual value.

PacifiCorp

In its 2013 IRP, PacifiCorp used a similar methodology as PGE to calculate CTP. PacifiCorp used third-party data over the course of 2007-2010 due to the unavailability of its own data.[36] Like PGE, PacifiCorp placed priority on taking measurements from the top 100 hours of its peak season, which is in the summer for PacifiCorp.[37] It also assumed a 90% probability that the resources would generate as much power during future peak hours.[38] The study resulted in a 4.2% contribution to peak for wind (as a percentage of nameplate capacity) and 13.6% for solar.[39] CUB has similar opinions about this method as PGE's method above—namely the concerns with relying on peak hours. In addition, the 90% probability addition seems to CUB to be an arbitrary number that devalues peak contribution.

PacifiCorp's 2015 IRP provided a more robust analysis of measuring contribution to capacity. Though PacifiCorp does not use ELCC to estimate the contribution to capacity, it uses an approximation that seems to come close.[40] As CUB understands it, the CF method as PacifiCorp applied it estimates LOLP values for all 8,760 hours of the year and uses LOLP to calculate weights for each hour.[41] The weights are multiplied by the capacity factor of each

[36] LC 57 – PacifiCorp 2013 IRP, Appendix O.
[37] *Ibid*.
[38] *Ibid*.
[39] LC 57 – PacifiCorp 2013 IRP, Appendix O.
[40] LC 62 – PacifiCorp 2015 IRP, Appendix N.
[41] *Ibid*.

resource by hour to determine a weighted capacity contribution.[42] PacifiCorp also separated the contribution to capacity by balancing authority,[43] which CUB finds to be appropriate and useful. The following table is the result of its study in the 2015 IRP:

Figure 3 – PacifiCorp's Contribution to Capacity Values[44]

	East BAA			West BAA		
	Wind	**Fixed Tilt Solar PV**	**Single Axis Tracking Solar PV**	**Wind**	**Fixed Tilt Solar PV**	**Single Axis Tracking Solar PV**
CF Method Results	14.5%	34.1%	39.1%	25.4%	32.2%	36.7%
2013 IRP Results	4.2%	13.6%	n/a	4.2%	13.6%	n/a

The benefit of this method, as defined by NREL, is that it is computationally less intensive and approaches the ELCC estimation after a "suitable" number of hours are considered.[45] PacifiCorp has incorporated all 8,760 hours, not just the peak hours in its estimation, which addresses CUB's concerns with other methodologies discussed above. In addition, PacifiCorp used actuals and updated its database, so the accuracy has likely improved since the previous IRP. CUB prefers this method to the approach taken in the 2013 IRP because it considers more hours while still taking into consideration the interaction with peak.

Idaho Power

Idaho Power's 2015 IRP does not go into great detail about its methodology in calculating contribution to capacity, though its numbers for solar capacity contribution are rather high relative to other utilities. The values Idaho Power provides in its IRP are in the table below:

[42] *Ibid*.
[43] LC 62 – PacifiCorp 2015 IRP, Appendix N.
[44] LC 62 – PacifiCorp 2015 IRP, Appendix N, p. 407.
[45] Madaeni S.H., Sioshansi R., & Denholm P. Comparison of Capacity Value Methods for Photovoltaics in the Western United States. NREL. July 2012. Accessed at http://www.nrel.gov/docs/fy12osti/54704.pdf.

Figure 4 – Idaho Power Peak Hour Capacity Credit[46]

New IRP intermittent generation—Peak hour capacity credit	
Resource	**Peak Hour Capacity Credit**
PV solar south orientation	28.4%
PV solar southwest orientation	45.4%
PV solar single-axis tracking	51.3%
Wind	5.0%

Though its methodology is not explicitly stated in its IRP, a stakeholder presentation from September 4, 2014 reveals that Idaho Power considered the top 150 load hours of the day and used a 90% exceedance value and assigned hourly weights to calculate the peak hour capacity contribution.[47] The Company does not provide an explanation of its methodology for calculating the 5% value for wind contribution.

Idaho Power's method is not as explicitly defined in the IRP as PGE's and PacifiCorp's. Thus, it is difficult to determine the pros and cons. The higher contribution to capacity is likely impacted by the fact that Idaho Power is a summer peaking utility, thus solar resources will likely lend a higher contribution. However, this does not explain the 5% value for wind contribution, so one obvious "con" to this method is that the details are not explained in full. Establishing a standard methodology of calculation would be one way to ensure that methodology is understood and consistent.

[46] LC 63 – Idaho Power's 2015 Integrated Resource Plan. Appendix C, p. 90.
[47] LC 63 – Idaho Power's 2015 Integrated Resource Plan. September 4 2014. Advisory Council Meeting Presentation. Accessed at https://www.idahopower.com/pdfs/AboutUs/PlanningForFuture/irp/2015/agenda_presentation090414.pdf.

III. Risks and Benefits of a Standardized Method

Staff's report identified the concept of a standardized method of calculating CTP in its report.[48] The purpose of developing such a method, as outlined by Staff, would be to compare values among the utilities for the purposes of precision and the impacts on PURPA QF contracts. CUB agrees that a benefit of streamlining the usage of a particular methodology is that it is useful for informational purposes. From a stakeholder perspective, this would be helpful for integrated resource planning. As far as it applies to the impact on QF contracts, CUB believes that the more accurate an approach, the better informed the QF contracts and setting avoided cost prices will be. In general, better information and analysis increases certainty, which reduces risk. To the extent standardizing a method of calculating CTP can more accurately inform the QF processes and inform the costs and risks to the utility, there would be a benefit to a streamlined process. However, this would only be the case if using a standardized process can be proven to more accurately determine CTP. Ultimately, CUB is most concerned with how streamlining a methodology can be proven to impact resource cost and risk.

Despite these potential benefits, CUB also believes that there may also be risks to incorporating a single measurement. Because utilities buy and generate power from a diversified geographical location, with different load profiles and service areas, and because renewable generation can be greatly impacted by region, not all utility systems are the same, and arguably, utilities will not gain the same CTP from a resource, even if they all build identical wind farms or solar PV systems if they are located in vastly different areas. It might also be more costly and computationally intensive to incorporate a new method.

[48] Order No. 15-077, Appendix A, p. 5.

In addition, Staff's report assumes that the same methodology is applied within the entire utility system, and CUB is not convinced that this should be the case. A case can be made for using different contribution to capacity methodology by region or even source of generation. Estimating contribution to capacity by source or region would solve the inconsistency problems Staff has highlighted[49] while also addressing the problem of incorporating the CTP of diverse generation sources. CUB understands that this requires a higher level of granularity, but it would arguably be the more accurate than a system-wide approach that spans multiple regions and resources.

IV. CTP Determination Schedule

Utilities currently estimate some form of contribution to peak in each of their IRPs. Staff indicated that CTP will likely change over time,[50] and CUB agrees. It is likely that CTP may change with the addition of new variable generation. It may increase as resources are spread with a higher geographical diversity,[51] but it may also decline with the addition of new capacity.[52]

CUB would be comfortable with a yearly or biennial revision to the CTP/contribution to capacity, filed with the IRP or updated with the IRP Updates, or both.

---

[49] Order No. 15-077, Appendix A, p. 5

[50] *Ibid*.

[51] Methods to Model and Calculate Capacity Contributions of Variable Generation for Resource Adequacy Planning. NREL. p. 6. March 2011. Accessed http://www.nerc.com/files/ivgtf1-2.pdf.

[52] Methods to Model and Calculate Capacity Contributions of Variable Generation for Resource Adequacy Planning. p. 18. NREL. March 2011. Accessed http://www.nerc.com/files/ivgtf1-2.pdf.

V. Preferred Methodology

Rather than state a preferred metric, CUB will provide a list of characteristics that should go into determining contribution to capacity. The ELCC method may suffice for some of these, but CUB notes that PacifiCorp's CF method in calculating contribution to capacity may be just as accurate and seemingly less computationally intensive as ELCC.

1) As CUB mentioned above, CUB does not believe that taking 50-100 hours out of the year is an appropriate approach to estimating renewable contribution to capacity. Though docket UM 1719 specifically states commentary on contribution to peak, CUB believes that renewables provide more value to the system than just 50-100 hours out of the year, and this should be reflected in resource planning methodology. For example, if wind is generating power during aforced outage in the 150th hour, then arguably, wind's contribution to peak may be higher during the 150th hour than it would be during the 5th hour when peak is high but there are no forced outages. CUB believes that the utility system is dynamic and is not convinced that taking the average of extreme values is appropriate.
2) Some modification that decomposes resources by technology and region. That is, aggregating summer and winter hours distorts the impacts of region (either due to weather or other factors). PacifiCorp has already done this to some degree by separating East and West balancing authority regions, but if possible, CUB would like to see more granularity. Both Idaho Power and PacifiCorp already took type of technology (e.g., fixed tilt vs. single axis tracking) into consideration, so this is doable.
3) Because utilities are concerned with reliability, CUB believes it is appropriate to use ELCC (or some other new metric) as a benchmark against contribution to *peak* capacity. However, CUB realizes that having two separate metrics (whatever they may be) will not solve the QF/PURPA concerns mentioned earlier in this testimony should utilities not use the same already contribution to capacity value in all of its undertakings.
4) Seasonal contribution to capacity analysis might be an option if the utility is concerned with reliability, realizing that it may be cumbersome to have two different metrics for different parts of the year.
5) Solar and wind data should be taken from the same year. It is advised throughout the literature because this ensures consistent analysis.[53]

[53]Milligan, M. Methods to Model and Calculate Capacity Contributions of Variable Generation. NREL. August 17, 2015. Accessed at: http://oregonpuc.granicus.com/MetaViewer.php?view_id=1&clip_id=23&meta_id=892.

VI. Conclusion

CUB has reservations with some of the ways contribution to capacity has been historically measured in Oregon. Though it is imperative to maintain system reliability, and because renewable generation cannot be guaranteed to follow load, CUB understands why the focus of renewable system contribution focuses on peak. Though peak hours should remain a concern, there may be additional, more useful metrics that separate contribution to peak (or even seasonal peak) vs. a more inclusive metric.

Accuracy is the most important factor to CUB. It is not useful to overestimate the value that renewables offer, because this might prompt reliability impacts, resulting in higher costs to ratepayers. At the same time, it is not useful to undervalue renewables because this means the system may be overbuilt, and this also means higher costs to ratepayers. Ultimately, accuracy is easiest on the pocketbook.

WITNESS QUALIFICATION STATEMENT

NAME:	Nadine Hanhan
EMPLOYER:	Citizens' Utility Board of Oregon (CUB)
TITLE:	Utility Analyst
ADDRESS:	610 SW Broadway, Suite 400 Portland, OR 97205
EDUCATION:	Master of Science, Applied Economics, 2015 Oregon State University, Corvallis, OR Bachelor of Arts, Economics and Philosophy, 2010 California State University San Bernardino, San Bernardino, CA
WORK EXPERIENCE:	Provided testimony and comments in dockets including LC 55, LC 56, LC 57, LC 58, LC 59, LC 60, LC 61, LC 62, LC 63, UE 264, UM 1505, UM 1657, UM 1662, UM 1667, UM 1675, UM 1716, and UM 1746. Also worked at CUB as an analyst on various other dockets, including UE 246, UE 262, UE 263, and UM 1460.