**BEFORE THE PUBLIC UTILITY COMMISSION**

**OF OREGON**

**UM 2011**

| In the Matter of<br><br>PUBLIC UTILITY COMMISSION OF OREGON,<br><br>General Capacity Investigation | NORTHWEST AND INTERMOUNTAIN POWER PRODUCERS COALITION PHASE III COMMENTS |
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## I. INTRODUCTION

NIPPC submits the following comments in response to the Oregon Public Utility Commission (the "Commission" or "OPUC") Staff's request for comments in Phase III of this proceeding on: "B. How Should Capacity Be Valued?, Questions 6 – 16."

## II. COMMENTS

The first step in determining how capacity should be valued (and priced) is to ascertain the resource's ability to provide capacity, which is reflected in the resource's capacity accreditation. The capacity accreditation quantifies the ability for a resource type or in some cases a specific resource to generate power to meet a defined load or load profile.[1] The need for power is determined by both the demand or load as well as the portfolio of other resources available to serve the demand.[2]

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1 The accreditation of resources is used to ensure a reliable determination of generating capacity, and is a fundamental element of Resource Adequacy ("RA") programs and capacity markets.

2 This accreditation is often established through the calculation of a resource's Effective Load-Carrying Capability ("ELCC").

The price paid for capacity is generally determined by the capacity market structure (e.g., bilateral, centralized, energy-only) and market design. Different types of capacity may qualify in different ways to meet the region's needs. Dispatchable fossil-fueled generation may have a different counting mechanism or value than solar, wind, run-of-river hydro or use-limited generation resources. In other words, assigning a price to the provision of capacity cannot be done in isolation of the particular capacity market structure and design.

The price for capacity, as reflected in common domestic wholesale pricing mechanisms, should ultimately be based on the supply and demand of capacity. In times of excess capacity, price should support ongoing operations and long-term resource needs; however, in times of actual or perceived shortage, price should support new entry or a multiple of the cost of new entry.

## A. Question 6: Does capacity value compensation require a capacity resource to be available to meet all reliability needs in all time frames?

No. Please see further explanation in answers to the sub-questions below.

### 1. Sub-Question a: Can a dedicated physical asset qualify to meet all reliability needs, or does it need to be supplemented with other resources?

If capacity is defined properly (e.g., through ELCC or another appropriate method) the limitations, if any, of individual resources will be identified and their capacity contribution will correctly reflect their ability to meet demand when and where it is needed. Use-limitations, fuel unavailability (e.g., solar at night), transmission limitations, and other restrictions will discount the capacity accredited to these resources.

This discounting will result in the need for and identification of compensating and incremental resources.

While a dedicated asset, such as a fossil-fueled generation resource, can qualify to meet all reliability needs, a portfolio of resources rather than a dedicated physical asset, will provide regional capacity needs most economically.

### 2. Sub-Question b: Can a portfolio of resources that meet the availability requirement qualify for the same or better compensation than a dedicated physical asset?

NIPPC interprets this question as asking whether there is an inherent benefit of serving load with a portfolio of resources or a singular physical asset. NIPPC believes that one of the primary objectives of a RA program is to ensure that individual resources are specifically identified and "counted" against a particular reliability need. Therefore, a group of dedicated, yet different resources can be equivalent to a single dedicated resource, so long as the individual resource capacity accreditation is reasonable. Simply put, three different resources that each have an ELCC of 0.33, when considered together as a portfolio, are the same as a single resource that has an ELCC of 1.0.

### 3. Sub-Question c: Can a financial contract qualify for the same or better compensation than a physical asset?

If the definition of "financial contract" is meant to refer to firm liquidated damages ("LD") contracts and does not involve an identified, physical asset, then careful consideration is needed in terms of how and whether these products meet the objectives of RA. LD contracts, if not properly evaluated and categorized could promote double counting and may not represent physical capacity at all. Such contracts, while useful financial and risk-hedging instruments[3] have been viewed as inconsistent with well-designed capacity-based reliability markets elsewhere. In fact, most organized capacity markets prohibit the use of financial (LD) contracts as a means of meeting RA targets, except for limited transactions originating outside the capacity market boundaries.

On the other hand, if the definition of "financial contract" is intended to identify "controlled generation," then it should be able to reliably meet demand in the same manner as an owned resource. For example, this could be a tolling agreement from an asset identified in a power purchase contract or agreement for all or a portion of the output produced by an identified asset. A non-resource specific system resource procured from a Balancing Authority would also qualify for the provision of capacity as a financial contract.

Importantly, however, in the State of Oregon, at this time power purchase contracts for asset-specific generation are not treated comparably to physical assets owned by regulated utilities in terms of allowance for return. This is because the Commission allows utilities the opportunity to earn a rate of return on owned, physical assets but power purchase contracts are not eligible for inclusion in utility rate base. This results in a utility resource procurement process that favors utility-owned resources over all types of financial contracts.

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[3] NIPPC has no objection to using non-specific financial contracts as a hedging mechanism. It takes no position on compensation levels, other than to say that those taking the risk obviously should be compensated for doing so.

## B. Question 7: Regarding the capabilities listed in question 4 above, what should be the qualification criteria for determining if a resource can meet these needs, assuming the information, communications and control systems are in place to support development of qualification criteria?

In NIPPC's earlier comments on this docket, we recommended that the Commission consider a regional approach to its capacity investigation which should include standardization of capacity accreditation. The qualification of a resource type or specific resource should be reflective of the market that the resource is serving and the methodologies that are embraced by that market. For example, the RA measurement for various resource types and objective determination of what is effective generating capacity or demand-response capacity can change under various conditions. The determination of whether a resource can meet need is dependent upon that resource's capacity contribution, which is calculated differently (e.g., through ELCC), depending upon the resource type and the seasonal or historical average capacity factors during peak demand.

## C. Question 8: Should supply-side and demand-side resources that demonstrate the capability to satisfy the qualification criteria for that type of capacity be valued in the same way?

If the supply-side and demand-side resources can serve load in a comparable manner, then the value or price paid for such should be similar or the same. In addition, the need (typically, for supply-side resources) or avoided need (typically, for demand-side resources) for transmission and distribution should be taken into consideration.

**D. Question 9: How should the value of each type of capacity be calculated and how should its temporal availability (e.g. short vs. long-term capacity) affect the valuation? In response to stakeholder requests for clarification, this question refers to the time period and duration for which a resource is committed by contract, ownership by a utility, or other arrangement.**

The contribution of capacity or capacity credit should be measured against established reliability targets. Typically, load has the obligation to both ensure RA and procure capacity for periods ranging from months ahead to multiple years ahead. Resource commitment periods are similar. In most markets, reliability targets are established looking one to three years forward. Any resource, regardless of age, ownership or contractual status that can meet those targets should be recognized for its capacity credit.

The value or price paid for capacity is usually similar across the region, while energy payments can differ based on short start times or fast ramp rates. Units that have use-limitations, have fuel or dispatch limitations or experience transmission restrictions should be discounted appropriately. This would be reflected in stacking capacity resources against forecast load duration curves which incorporate resource diversity in various resources such as solar, wind and low hydro conditions.

Duration is not an inherently superior attribute of capacity needs, due to the fact that a resource should not be evaluated in isolation but as part of a portfolio. Some resources will be able to provide various capacity products over time, and that “stacked” capacity should be recognized.

**E. Question 10: How should temporal and durational attributes of capacity be calculated? In response to stakeholder requests for clarification, this question refers 'temporal availability' in a different sense: when and how a resource is capable of serving load, regardless of its ownership structure or contractual arrangements.**

See previous answers describing capacity accreditation through analytic methods such as ELCC.

**F. Question 11: If locational capacity is something that should be compensated, which factors should be used to inform the locational value of capacity?**

The deliverability of generation to load is a critical factor in establishing capacity credit and value. If transmission limits create local load pockets which can only be served by a limited number of generators, reliability targets should be distinctly established in those constrained areas and capacity prices should rationally rise to the long-run marginal cost of service. This cost could be the long-run cost of new generation, new transmission, load management or other long-run fixes to the constraints.

Similarly, the lack of or avoidance of congestion associated with transmission or distribution should be reflected in the determination of value. And, there may be a need to compensate for locational value during certain circumstances. For example, when the system is stressed during an arctic express weather condition or during a low water year.

**G. Question 12: How does the scale of a given resource affect its value?**

First, recognizing that the risk profile for singular, large resources may be different than multiple smaller resources (but this should be recognized in the capacity accreditation), the accreditation should not *depend* on the size of a resource, but rather the ability of the resource to meet the reliability targets. As one constructs the analytic framework for accreditation, there may be constraints that naturally limit large units from effectively serving load (e.g., very high minimum generation levels, high number of required hours of operation between starts, etc.). Thus, a portfolio of resources would meet a regional need. For example, there may be a limit on the number of long start units procured for regional RA, according to ELCC and load duration curves.

Second, there is not a correct threshold size per se of a generating resource, or a demand-side resource. To the extent a load deficit exists, it can be met with a singular supply or multiple supplies. Due to the integrated nature of the Pacific Northwest region, there are market-hubs as well as import and export market opportunities for excesses and price optimization which can compensate for concerns with projects that are “too big.” The integrated nature also lends itself to aggregating project output in order to compensate for those resources considered “too small.”

The Capital Expenditure funds that are available to invest in new projects or to upgrade or maintain existing projects can impose a limit in terms of the financial risk that a developer is willing to assume. Some large scale generating projects are under development in the Pacific Northwest, e.g., Site C – Clean Energy Project, and large scale transmission projects such as Gateway; however, these are sometimes very remote, complicated, and expansive endeavors. Most of the capital expenditures for marginal resources are expected to involve modular, or locational-specific installations including gas-fired generation, pumped hydro storage, battery storage, renewable resources, demand response, etc.

**H. Question 13: Currently, simple-cycle gas plant costs are generally used to value capacity. Is this method still appropriate for some types or categories of capacity?**
**a. If yes, for which types?**

Yes. While the next unit of capacity could be solar, wind, batteries, pumped hydro storage, gas-fired generation, small scale hydro, or something else, all of these resources, other than gas, are use-limited, and may be non-coincident with peak demand, especially over a multi-day period. Said differently, the ELCC of these resources may require several MWs of installed capacity to yield a MW of effective capacity.

Gas-fired generation, however, is not use limited and can be relied upon to operate coincidentally with peak loads. As a result, gas-fired generation remains an appropriate benchmark for the next unit of capacity: one MW of gas-fired generation equals one MW of effective capacity.

In terms of gas technology, aero-derivatives and frame units are obvious choices, although more exotic options that allow for zero-emissions voltage support or black-start capability may be of interest. For load deficits in the thousands of MWs, combined-cycle combustion turbines may be the appropriate benchmark; making the point that the best benchmark may need to consider the magnitude of the demand.

Frame units (GE F-series or Siemens 501-series) were initially designed for heavy industry. This technology can be made to start quickly, but not as fast or as cleanly as the aero-derivatives.

Aero-derivatives are probably the best choice for fast start, flexible, fast ramping, and efficient generation. This technology can offer 10 minute start-up and substantial operating ranges. GE offers models for 50 MW (LM6000) or 100 MW (LMS100), and other manufacturers have similar models. These models can be “ganged together” to create substantial plant capability. Of these options, the LMS100 seems to be the current reference point for capacity due to its heat rate and ability to both adjust generation on a short time frame to integrate in daily levels of variable renewable generation as well as maintain a high level of generation when needed due to extended weather conditions that may limit solar and /or wind generation. The LMS100 technology has achieved significant penetration.

## I. Question 14: Should capacity compensation for Distributed Energy Resources (DER) be based solely upon contribution to meeting an identified system need, or should it be supplemented with other factors considered in DER valuation? How relevant are the following factors for capacity valuation, and which are missing?

In cases where a DER can provide local reliability needs that benefit the distribution system, and defer other transmission and distribution upgrades, that resource should be compensated at a greater value than a regional capacity value. One potential mechanism for establishing incentives for developers to build resources that provide locational value and benefits to the distribution system would be a request for proposal process to solicit bids that would provide additional compensation for a unit built in a higher cost location and providing locational benefits, with compensation from the distribution rate, reflecting payments from the load benefitting from the locational resource. The resource owner would depend primarily on energy and capacity markets for normal operations, but the supplemental payment for a specified period, for example 10 years, would ensure needed grid benefits are obtained and compensated.

## J. Question 15: How can proper calculation of RA capacity help to cost effectively address the region's RA issues?

NIPPC believes that the most cost-effective approach to the region's RA issue is to develop and adopt a standardized approach to capacity accreditation rather than individual utility methods, and a market design that ensures that rates are fair, just, reasonable and sufficient, while ensuring safe, reliable and high quality power supplies that can best result from the diversity benefits of a wide area footprint and portfolio of resources.

NIPPC offers the following six principles for consideration to which adherence will maximize the benefits of a RA program to the region:

1. **Reliability:** The Program should assure reliability of electricity service to the region based on industry-standard reliability metrics.
2. **Independence:** Determination of need and evaluation of resources must be overseen by a Program Administrator that is independent of market participants.
3. **Non-discrimination:** The resource evaluation (accreditation) must be technology-neutral and must enable all resources to participate regardless of ownership.
4. **Competition:** The Program design should be consistent with existing state and local direct access programs and should facilitate the ability of Balancing Authority Areas to pass compliance obligations through to multiple load-serving entities within their service areas.
5. **Transparency:** The Program Administrator should undertake all calculations in a transparent, auditable manner and all information should be public to the maximum extent possible.
6. **Practicality:** The Program should not be unduly burdensome to comply with and should be consistent over time.

**K. Question 16: Given your answers to all of the above questions, do you have recommendations about what types of capacity should be compensated, how to define those types of capacity, and do you have examples of calculations or methodology suggestions you would like to offer?**

The region has initiated a conversation regarding the appropriate structure and design for a regional capacity market, and NIPPC looks forward to participating in that conversation. Utilization of the Pacific Northwest region's diverse resources will result in the most economic capacity supply mix, but a regional study of accreditation is necessary with broad participation. Individual Balancing Authority RA constructs may result in sub-optimal solutions and higher costs to ratepayers. NIPPC looks forward to reviewing the comments in this proceeding and other regional processes, but at this time, believes that it is premature to suggest a particular methodology.

NIPPC believes that the region is facing significant capacity deficits during the 2020-2030 time period and that the lack of a regional capacity market has been aggravated by the practice for large utilities to rely on “market purchases” or “front office transactions” in their integrated resource plans. Recent studies by E3 and the Northwest Power and Conservation Council have demonstrated a near term capacity need growing to as much as 8 GW by 2030. In response, we encourage the State of Oregon to work with the region’s utilities, and the independent power producer community and stakeholders, to investigate the formation of a Regional RA Program.

NIPPC supports the Commission’s direction for this docket, which is to, as much as possible, determine one or at least consistent methodologies to calculate value for capacity. The status quo is that capacity is valued differently for solar resources (from Docket Nos. UM 1910, UM 1911 and UM 1912), renewable resources (from Docket No. UM 1719), avoided costs under the Public Utility Regulatory Policies Act (from Docket Nos. UM 1129, UM 1610, UM 1728, UM 1929 and UM 1730), energy efficiency (Docket No. UM 1893), and the various utility requests for proposals. This has resulted in the Commission determining the capacity value for a resource based on certain regulatory or policy objectives (i.e., the current approach values capacity owned by utilities over capacity provided by independent power producer owned generation through power purchase agreements or direct access). NIPPC believes that capacity value should be based on a resource’s actual value and ability to contribute to RA.

## III. CONCLUSION

NIPPC appreciates the opportunity to submit comments on this critically important issue for Oregon and the region, and looks forward to continued participation in this proceeding.

Dated this 13th day of January 2020.

Respectfully submitted,

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