Resource Adequacy Technical Committee Meeting
September 24, 2007 – 10:00 a.m. to 2:30 p.m.
Northwest Power and Conservation Council Office

Agenda

PARTICIPANTS: John Fazio, Wally Gibson and Michael Schillmoeller (NWPCC), Mary Johannis and Eric King (BPA), Greg Mendonca (PNGC), Dick Adams (PNUCC), Villamor Gamponia (PSE), Steve Weiss (NW Energy Coalition), Howard Schwartz (CTED), Rod Noteboom (Grant PUD) and Stefan Brown (PGE)

PHONE PARTICIPANTS: Don Tinker (Seattle), Nicolas Garcia (WA UTC) and Becky King (Chelan)

I Decision on Economic Risk Metric and Target

A Council's Economic Risk Metric

Michael Schillmoeller indicated that the Council's metric, i.e. $TailVaR_{90}$, was selected as the metric for the Council's Fifth Power Plan because it can measure bad outcomes, both in terms of cost and economic risk and physical reliability (i.e. unserved energy and LOLP); it also captures portfolio diversification. It measures strictly better outcomes, as defined by the parameters described above.

The Council ran its Portfolio Model for 750 different futures for each plan. A future is defined as all the parameters over which utilities do not have control, such as uncertainties regarding loads, resources, hydro conditions and fuel prices. A Monte Carlo algorithm is used to pick a 20-year future. One future contains 20 draws of water years from the 50-year record; reservoirs are operated continuously over that period. The model does not have perfect forecast ability, so it decides on resource construction and acquisition based on early conditions, but may change course based on changing conditions. The average of the 10% of the worst outcomes in terms of costs, i.e. the $TailVaR_{90}$ value, is calculated for each plan. The goal is to minimize $TailVaR_{90}$. If plans require curtailments, they were priced at $250/mwh because that was the cap at the time. Studies show the biggest blunder in terms of costs is to overbuild. The set of plans plotted for a curve that minimizes cost and risk are the plans along the "efficient frontier" curve. In each of these plans, the implied "economic" standard required more resources than the Council's adopted resource adequacy standards because of the goal to minimize both cost and risk, i.e. the probability of bad outcomes. The Fifth Power Plan was selected from this curve.

B Methodology to choose risk target point

John Fazio recapped the discussion from the last meeting, where the group was leaning toward using the Council's methodology, but wanted more information. John asked the group if anyone disagreed with using $TailVaR_{90}$ as the metric for the Economic Standard? John stated that the Forum (Technical and Steering Committees) can either base the selection of the Economic Standard on the Council's metric and a plan along the "efficient frontier", most likely the plan selected as the Fifth Power Plan, OR some other methodology. John noted that although the Fifth Power Plan is somewhat out-of-date, work on the Sixth Power Plan will begin within the next six months. This is a public process in which the Forum can engage.

Suggestions were made that the presentation to the Steering Committee depict LOLPs for the various plans; as well as the translation to a regional load resource balance and planning reserve margins. Dick Adams stated that this group should differentiate between the methodology, which uses the $TailVaR_{90}$ metric, and the target. One target is the load resource balance associated with the Fifth Power Plan.

Nicolas Garcia questioned why use $TailVaR_{90}$ rather than $TailVaR_{85}$? Council staff indicated, this type of a change to the metric could be examined in the Sixth Power Plan process. There was a lot of discussion regarding the nature of the Technical Committee's recommendation, i.e. should this group recommend both a metric and target, or just a metric? **Decision:** The Technical Committee decided to recommend the Council's methodology and the use of the $TailVaR_{90}$ metric to the Steering Committee as the Economic Metric. No target is recommended currently, rather the Technical Committee recommends that the Forum engage in the Sixth Power Plan process in order to make an informed decision on the Economic Target.

II Evaluting Hydro Capacity for Standard / Derating PNW Hydro for PNUCC and WECC Reporting

Mary Johannis discussed a methodology for evaluating the contribution of regional hydro capacity toward meeting the PNW Capacity Adequacy Standard. An important component of this effort is to enable a reasonable translation of PNW sustained hydro peaking capacity into a peak hour value for reporting to WECC for its Power Supply Assessment (PSA) and possibly to PNUCC for its Northwest Regional Forecast (NRF).

The Technical Committee has already decided to recommend using an 18-hour sustained peak duration (6 hours around the highest peak on the daily load curve over 3 days). The suggestion is to select combinations of random events, i.e. water and temperature, that yield a 1-in-20 year type adverse water and adverse load event.

Mary provided an example of how to evaluate hydro capacity by building on an example from last month's meeting. This example showed BPA's operation of the FCRPS during a recent winter cold snap event. Mary proposed escalating expected load to maximize hydro over both peaks of the winter daily load shape and purchasing to meet load during shoulder and off-peak times. Purchase assumptions would need to be aligned with regional assumptions regarding the availability of light load hour energy from both within and outside the region. The Federal Columbia River Power System (FCRPS) is assumed to operate under "cold snap" mode, which involves obtaining permission to increase the draft at Coulee from 1.5 ft/day to 2 ft/day and maximizing the output from Dworshak.

The Genesys model currently limits Coulee to 1.5 ft/day; however, John said that Genesys can include a change in the Coulee rate of draft limit; it could also include an additional 10 kcfs out of Canada during emergency situations, if the group agrees this is an appropriate assumption. John suggested that we review all the "emergency" actions in Genesys and make sure they line up with what would be done in an emergency. Mary suggested we use the terminology "cold snap" operations to differentiate between a cold snap and a true "emergency", which might require violating fish constraints.

In the explanation of how BPA evaluates FCRPS capacity, Mary indicated that FCRPS capacity is decremented for both operating reserves and an extra 1000 MW before the sustained hydro peaking capacity is evaluated. Rod Noteboom asked why BPA adds the 1000 MW to the contingency reserve. Mary said that it may reflect the potential loss of the Columbia Generating Station (CGS). But Rod said that because of NWPP's reserve sharing

agreement, BPA may not need to do that. Mary thought that BPA was just being conservative in setting their reserve requirements.

Mary said that the load shape used to assess hydro sustained peaking capability would be extrapolated from a normal temperature load shape. The streamflows on slide 6 are from the ESP program, which creates synthetic natural streamflows based on current year conditions. What the graph tells us is that the runoff doesn't matter much in terms of determining the hydro sustained peaking capability. The storage in the system can "fill in the holes" for those years with low streamflows.

Wally Gibson asked, does the hydro capability include the effects of off-peak purchases? The answer is yes. Mary said the assumption is no more than the assumed market depth, e.g. 2000 mw off-peak.

Slide 7 shows a large decrease in hydro sustained peaking when streamflows get really low but for the top 4 quintiles of hydro conditions, the peaking capability doesn't change much at all. Wally asked if the end of Feb contents changed much. Eric said he tried to keep them constant but occasionally the system could not recover.

Mary's point is that it doesn't matter much which water condition to use to select the hydro peaking capability as long as it is above critical hydro. We shouldn't use the lowest water because it reflects a 1-in-78 year event – much too rare in combination with a reserve margin component for temperature.

Mary is suggesting using the peak hour hydro capability from this analysis for submittal to WECC because the planning reserve margins for the one and 18 hour values are not significantly different.

Don Tinker asked if the HOSS was compared to Columbia Vista. Mary said that Columbia Vista is only used one month out. Don corrected Mary and said that slice customers were seeing at least 3 months of Columbia Vista results. Mary indicated she would check with Jennifer Bennett regarding the assumptions used, but cautioned that assumptions from operational studies may not be compatible with hydro capacity evaluations for resource adequacy purposes.

Mary will do some checking to see what some of the west side and Willamette owners consider to be candidate events for an adverse water event. The goal is to select one event for the Region with both adverse hydro and adverse temperature components as the 1 in 20 year event under which to plan regional hydro capacity.

WECC is asking for adverse hydro not critical hydro and they ask for 1-in-2 loads. Then they put a 1-in-10 load delta into the reserve margin calculation. WECC's major concern is to understand how much surplus capacity is transferrable from region to another. BPA wants to get the hydro peaking capacity evaluation right so they neither over or under-acquire resources for peaking purposes.

The main purposes for this are for WECC reporting and for individual utility uses and for reporting to the NRF and possible for inclusion in the White Book. So, Mary will ask hydro operators about their adverse hydro and see if she can come up with a single condition for the region.

III Steps toward a Final Capacity Metric and Targets

John stated that changes such as model improvements, data validation and better counting protocols for hydro and wind capacity do not result in changes to the standard, which is a Loss of Load Probability of 5%. This means that the Region deems the probability of incurring a 1 in 20 year load curtailment due to generation insufficiency as acceptable. Better model simulations of the power system or translations of resources to capacity and energy adequacy calculations do not change the fundamental premise that an LOLP of 5% or less is acceptable.

IV Considerations for Changing the Current Standard

John then pointed out that changes, such as counting different events as misses in the Genesys model, would constitute a change to the standard.

V Next Meeting

November 1st 10 to 3.