FINAL

Resource Adequacy Technical Committee Meeting
February 5, 2007 – 10:00 a.m. to 3:00 p.m.

Notes

ATTENDEES: Mary Johannis, John Fazio, Wally Gibson, Stefan Brown, Tom Haymaker, Clint Kalich, Silvia Melechiorri, Howard Schwartz, Massoud Jourabchi, Rob Diffely, Rod Noteboom and Jim Litchfield.
PHONE PARTICIPANTS: Becky King, Chris Robinson, Steve Weiss and Nicholas Garcia.

Technical Committee's 2007 Work Plan

Mary Johannis presented a proposed work plan for the PNW Resource Adequacy Forum. Following are some of the work plan-related issues discussed:

The BPA-Council Wind Integration Group would like the Forum to deal with the question of how to count wind as contributing to the capacity metric with help from them. The committee agreed that it is our responsibility, but that we would be happy to get better data from the wind integration group.

Mary indicated how the work plan will shape the agendas of future Technical and Steering Committee meetings. For example, a discussion of the duration of the sustained peak should be on the next meeting's agenda.

Clint Kalich asked how this effort is related to the development of the 6th Power Plan. John said that work on that plan should start in a year or so. But, the philosophy of the 5th plan (and presumably for the 6th plan) is to plan for a higher standard than just a minimum physical adequacy standard, i.e. an economic standard. One of the work plan tasks is for the Technical Committee to take a closer look at the economic standard and suggest options for changes, if needed.

Efforts to Coordinate Resource Adequacy & Washington State Reporting

In 2006, Washington State legislature passed HB 1010 requiring preparation of Integrated Resource Plans (IRPs), or scale-downed versions for smaller utilities. Other legislation and initiatives have been passed requiring a certain percentage of future resources to come from conservation and renewables. HB 1010 defines an IRP and asks WA Dept of Community Trade and Economic Development (CTED) to develop a common cover sheet summarizing forecasted loads and resources to be submitted with IRPs and to incorporate reporting requirements addressing conservation and renewable resources. CTED will then add up the cover sheets to develop a report to the legislature on the adequacy and type of Washington's current and future resources to meet expected loads. CTED and Washington Utilities and Transportation Commission (UTC) are coordinating with each other to develop a common IOU and public utility reporting process.

CTED has divided utilities into large and small categories with 25,000 customers as the dividing line in terms of reporting requirements. BPA's full requirements customers are

placed in the small utility category even if they have over 25,000 customers. Howard Schwartz provided an overview of the cover sheets being developed. He indicated CTED is working with PNUCC to try to make the CTED process as compatible as possible with PNUCC's resource adequacy reporting process to minimize the burden on reporting utilities. A number of issues have surfaced with respect to coordinating the two reporting processes. One issue is that the Washington process requires more granular data than the PNUCC one. Another issue is defining what is the reporting year? Should it be August through July, as is typical for hydro utilities; or October through September; or the calendar year? The first report is due to the Washington legislature in September, 2008. This timing allows for potential alignment of the two reporting processes, whereby data is obtained in the December through January timeframe every year.

Integrating NW Standards into WECC's Interim Capacity Metric/Target

John Fazio presented a PowerPoint on changes to the Pilot Capacity Adequacy Standard results based on updated information. The Council has developed a model to provide 50-hour loads so that the adverse temperature reserves can be calculated using consistent load and resource durations (i.e. over the 10 hours per day and 5 days sustained peaking period) rather than using loads based on daily average temperatures. John reviewed how these reserves were calculated last year starting with the load based on average daily temperatures for the average of the peak days in winter and summer. This temperature condition was termed the expected peak temperature, EPT. **Action Item:** Stefan Brown suggested that the terminology needs to be changed to reflect that this is the temperature for some peak duration based on the average over the coldest or hottest days for the period of record, not the peak temperature on the coldest or hottest day.

John then presented how the adverse temperature reserve margins have changed based on 50-hour loads as compared to the daily average temperature loads. No significant changes are noted in the winter since the winter adverse temperature reserves are all around 15% now, but summer adverse temperature reserves have decreased to about 4%. The overall capacity targets have not changed because these are derived from the LOLP analyses. The numerical targets may change as we contemplate changes to the LOLP analyses. In response to questions from the group, John explained that planning adjustment reserves covers contingencies not covered by operating or adverse temperature reserves. Examples of these contingencies might be a situation where there is a lack of spot market, or a forced outage of a generator lasts longer than an hour.

The revised analysis for the Region using 50-hour loads rather than the daily average temperature loads for the peak day shows that the Region is currently still surplus with reserve margins of 38% in the winter and 22% in the summer. However, the latest court-order spills, which decrease FCRPS capacity and energy have not been factored into this evaluation. **Action Item:** John will send the Technical Committee an analysis of last year's spill operation as an indication of the decrease in FCRPS resources. John then showed a slide, which indicates that while the Region is still energy-constrained in the winter, it will hit the capacity constraint before the energy constraint in the summer.

John showed his analysis of a translation of the capacity targets for the sustained peaking period to a one hour peak duration. A 25% winter sustained peaking target translates to a 44% single hour peak target; and a 19% sustained summer peaking target translates to a 41% single hour target. This translation is pertinent for two reasons:

- At the November 17 Technical Committee, the group decided to report just the peak hour hydro capacity to PNUCC. Therefore, PNUCC needs to use a capacity target associated with one hour peak hydro capacity in performing the "bottom-up" resource adequacy assessment.
- WECC is in the process of trying to improve the Power Supply Assessment (PSA), which is a quasi-resource adequacy evaluation of the Western Interconnection and its sub-areas using a one hour peak capacity metric. In the past couple of years, the PSA has also included an energy assessment for the Northwest in recognition that a one hour peak capacity metric is insufficient to assess whether the hydro-dominated NW is adequate. Footnotes have been added to the PSA capacity assessment to discount the validity of the assessment for the NW. As WECC strives to improve its PSA, one possible solution is to use the PNW capacity targets as translated to a one hour peak metric (44% and 41%, respectively for summer and winter) and not de-rate hydro capacity. The PSA has historically de-rated NW hydro capacity by 3,660 in the winter and 4,880 MW; however, the basis for this derating is obscure. There was an extended discussion regarding the methodology WECC used to de-rate NW hydro. A sub-group decided to meet after the close of this meeting to strive to reach consensus on an interim hydro de-rate for the PSA. (*This sub-group decided to use the 7,000 MW Northwest Power Pool (NWPP) as the interim hydro de-rate. This de-rate is for the NWPP footprint and assumes critical hydro and a sustained hydro peaking period of 12 hours. With the WECC capacity metric based on a one-hour peak duration, the NWPP's sustained peaking duration is a better fit than the adopted Pilot Capacity Adequacy Standard's 50 hour sustained peaking duration because loads averaged over 4 hours are more aligned with a one hour peak metric than loads averaged over 10 hours.)*

The group discussed the options for how to ask WECC to depict capacity adequacy in the PNW. One option is to expand the PNW Energy Assessment, which is currently attached to the PSA, to also incorporate a capacity assessment for the PNW. Another option is to use the translated one-hour capacity reserve margin discussed above. A third option is to de-rate hydro more than the current de-rate in the PSA. The Technical Committee agreed that the PNW appendix in the PSA should be expanded to also include a capacity adequacy assessment using the adopted Pilot Capacity Adequacy Standard. There was no agreement whether to increase the de-rate, or increase the reserve margin in the PSA. *(See the sub-group's decision on hydro de-rate above)* Stefan Brown was concerned that the one hour translation may be misinterpreted. Steve Weiss advocated that the translated reserve margin should be used in the WECC PSA, at least as a scenario. If the translated reserve margin is used as one of the scenarios in the PSA, then for that scenario, the hydro capacity should not be de-rated.

Council's Short-term Load Forecasting Model

Massoud Jourabschi explained that this model was developed as an action item for the 5th Power Plan. This model was designed to be able to forecast loads 3 to 5 years out on an hourly basis on a coincident peak basis. Council staff confirmed that the four weather stations used for estimating load is sufficient. Data from additional weather stations did not significantly increase the accuracy of forecasted load. One of the first steps was to develop temperature normalized historical hourly loads and compare them to the annual loads forecasted by the Council's long-term load forecasting model. This validation method supported the reasonableness of the results of the Short-term Model.

Massoud then explained how the model can forecast hourly loads for a certain level of development taking into account temperature deviations. The model escalates temperature sensitive load based on a load history of about 10 years. Loads further back may not accurately reflect current air conditioning loads, or status of house insulation. Therefore, only recent historic loads are used. Since this is an hourly model, it is relatively easy to define loads over a sustained peaking period. However, you need to consider how to treat weekend loads. Massoud showed how this model could forecast sustained peaking loads for a 1 in 20 weather event. If you look at only the peak hour loads, the load increases by 200 MW over the 50-hour sustained peaking period.

This model is publicly available.

Translating Regional Standards into Useful Utility Guidelines

There was only 15 minutes left in the meeting by the time the group arrived at this topic. So, rather than a brainstorming session, John presented a number of options for translating the regional standards to individual utility analyses to spur discussion at a future meeting. One option is for each utility to perform its own LOLP analysis. The Council's GENESYS model is publicly available and could be used by individual utilities, if the Council modified it for such use. However, there would need to be agreement on some common set of assumptions and methodologies.

The other approach is to develop guidelines for translating energy and capacity metrics and targets to individual utilities. One option is come up with specific methodologies for allocating the planning adjustments to individual utilities. A second option is to use the 85th percentile water condition for assessing the adequacy of hydro utilities. This option would not require the allocation of planning adjustments and recognizes that the planning adjustments are a product of the hydro-dominated nature of the PNW's power supply.

Silvia Melechiorri raised the issue that a utility's LOLP targets are commonly 1 day in 10 years, rather than 1 event in 20 years. She indicated that the state regulator for her utility would probably not agree to acquisitions consistent with, for example, a 40% planning reserve margin, which is the 25% and 19% sustained peaking capacity targets translated to a one-hour target. Mary pointed out that depending on a utility's hydro-

thermal resource mix, the sustained peaking capacity targets may not be applicable. For example, a pre-dominantly thermal utility would likely have a lower capacity target based on a one-hour peak capacity metric rather than a 50 hour sustained peaking metric.

A number of participants questioned the need for individual utility guidelines. The group decided to develop options for guidelines and refer the question of the need for the guidelines to the Steering Committee. John and Mary will schedule a Steering Committee meeting after the next Technical Committee Meeting.

Next Meeting

The next meeting is scheduled for March 16 from 10 to 3 at the Council's offices.

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