Final

Resource Adequacy Technical Committee Meeting

August 23, 2006 – 9:30 a.m. to 2:30 p.m.

Notes

ATTENDEES: John Fazio, Mary Johannis, Wally Gibson, Clint Kalich, Dave LaVee, Ken Corum, Massoud Jourabchi, Malcolm McCoy, Rod Noteboom, Stefan Brown, Rob Diffely, Kieran Connolly, Tom Haymaker, Ted Coates, Dana Tonlson, Anna Miles and Sue Kuehl
PHONE PARTICIPANTS: Aliza Seelig, Phil Popoff, Phil Devol, Don Tinker, Steve Weiss, Howard Schwartz, Becky King, Dave Vidaver, Nicolas Garcia

I July 21st - 24th Heat Wave

A Declaration of NERC Alerts and California Emergencies

Mary Johannis relayed the concern expressed at the July 28 Steering Committee regarding the pilot capacity standard. Members asked, why did a number of NW utilities declare NERC alerts on July 24th when the capacity surplus applying the assumptions of the pilot standard over the 10 hour duration was shown to be 58% for the PNW? The Steering Committee asked the Technical Committee to investigate whether the July 24th event warrants modifying the pilot capacity standard.

John Fazio summarized a BPA-NWPCC-NWPP conference call in which Jerry Rust had indicated that a number of utilities under forecast temperatures on Monday, July 24th and sold forward; this led to a scramble to purchase in the spot market and, in some cases, the declaration of NERC alerts. Mary stated the problem might not have occurred if the event had occurred on Wednesday, since stale forecasts (from Thursday or Friday) were used to predict Monday's loads and schedule sales due to reduced utility staffs over the weekend. Massoud Jourabchi explained the temperature deviations for the time period 7/21 – 7/24. He indicated that the Thursday (7/21) forecasts for Monday (7/24) were under forecasted by 4 degrees on a regional basis. The average regional temperature for Sunday was the highest average temperature for the region since 1928. The preliminary analysis shows that in July for every degree increase in temperature, above 67 degrees, daily load increases by about 180 aMW, which means that the under forecasted temperatures resulted in an unexpected load increase of about 720 aMW on July 24th.

Other factors leading to this event was the extreme heat across the entire Western Interconnection and especially in California. The CA ISO pegged July 24th at a 1 in 50 year event. In the PNW, Sunday's (7/23) temperatures were record-breaking, constituting a 1 in 78 year event. Neither the PNW nor the California resource adequacy metrics and targets are based on such severe events. CAISO experienced a peak load of over 50,000 MW, which was not expected until 2010. For this reason, they had to declare Stage 1 and 2 emergencies. A CEC staffer indicated that 800 MW of DSM was called upon in California at time of coincident peak. At this peak, only 100 – 200 MW of load lost on July 24th due to distribution (transformer) outages.

The Mid-C purchase index showing prices of $400/mwh and above confirms the scarcity of resources indicated by the declaration of NERC alerts and CA ISO emergencies.

B FCRPS Operation

Mary described the FCRPS operation during the period leading up to the afternoon of July 24th. BPA started to set up the Columbia River to maximize generation at the Lower Columbia River hydro plants (i.e. south of the North of John Day cut-plane) on July 21st anticipating very high loads in the NW and California on Monday, July 24th. The following preparatory actions were taken:

- Deferred previously scheduled maintenance actions;
- Secured a 2 ft/day draft rate at Grand Coulee (normal maximum rate is 1.5 ft/day)—only 0.7 ft/day was actually used;
- Secured permission to curtail fish spill, if necessary to avoid public health and safety emergency, through unscheduled meeting of the Technical Management Team (TMT) for fish operations. Fortunately, **no spill curtailment** was necessary;
- Received permission to modify reservoir elevations and tailwater exceedence at a number of reservoirs.

An analysis of the FCRPS sustained peaking capacity for July 24th event indicates that actual FCRPS sustained peaking capacity over the 10 hour period of the pilot standard was 13,581 MW. Under 1 in 2 loads, or expected temperature conditions, the sustained peaking capacity would have been about 12,100 MW. So, on the order of about 1,450 MW additional sustained peaking capacity was made available due to the actions above. Theoretically, between 400 and 800 MW could have been made available, if needed, but transmission limitations may have precluded deliveries of this power to the extent it would have had to be generated out of the upper Columbia, including Grand Coulee.

BPA was not selling into the market for economy reasons during the afternoon on July 24th; they reserved any sales for reliability purposes only. NW utilities, which declared NERC alerts, had priority to BPA's power over CAISO, which had declared Stage 1 and 2 emergencies.

C How did wind perform?

Rob Diffely described the performance of 477 MW of wind generation in the BPA control area. During the peak hours in the afternoon, the capacity factors were 7-8 %; over a 10-hour period, the capacity ranged from 13 to 15%. Rod Noteboom described Grant's operation of their 12 MW of wind capacity, which did not generate much or, at all, on peak. CA ISO stated that less than 5% of California's wind capacity was available to meet peak loads. Clint Kalich indicated that Stateline was not available on July 24th; however, PSE's wind performed at a 20% capacity factor.

D NW Utility Reports

Grant's diesel generator was ready to generate and provided reserves. Grant was able to meet load with their resources.

Avista bought forward to meet load, but their system was still tight. In response to a press release, Avista secured some demand-side management.

Snohomish had 60 MW higher load than anticipated; lost 10 MW from their cogen plant and purchased 85 MW to serve load. On the hour when Colstrip tripped, Snohomish could not find generation to purchase. They negotiated to curtail their contract with SMUD by 50%. Because Snohomish wanted to coordinate a press release asking for conservation with their neighboring utilities, they did not issue it until 2 pm reducing its effectiveness.

Tacoma was able to forecast peak load and had sufficient resources to meet load. They increased their hydro releases to sell into the market. Their peak load was 620 MW and 633 MW on Friday and Monday.

PNGC had under forecasted load and had to scramble to meet load.

E Firm versus Spot Exports

Wally Gibson presented information on the N-S intertie transactions on BPA's share, which shows 1,750 MW IPP generation going to California. The only reason the interties were not loaded completely to the OTC was that the North of John Day and North of Hanford paths were at OTC not allowing any additional generation east of the cut-planes to be delivered to the interties. The bottom line is that all the IPPs were generating at capacity, much of which appears to have gone to California. The IPPs have indicated that they would reserve their generation for the NW, if they had long-term contracts. Without such contracts, they will sell on the short-term market to the highest bidder.

CONCLUSION: There is a need for a meeting or meetings among Northwest utilities to clarify operating and communication protocols in extreme temperature or emergency events and what constitutes an emergency. One of the lessons learned is that we need to be able to call an ERT (Energy Response Team) for a capacity event such as occurred on July 24th not just for an energy event such as occurred in 2001. Possible forums for such meetings might be an already scheduled October NWPP meeting, or perhaps a separate workshop specifically scheduled for this discussion.

II Capacity Targets (Winter and Summer)

John explained that since the Steering Committee has already agreed upon the capacity metric, i.e. the way capacity adequacy is measured; his presentation will focus on the targets, i.e. how much constitutes adequacy.

A Definition of an Extreme Temperature Event

Since the July 28th Steering Committee meeting, John, Ken Corum and Massoud revised the temperature differential methodology to only include the daily average temperatures from the coldest day in every month for the 78 year period of record instead of all days in every month for this period. As expected, the temperature differentials have increased for the 1 in 20 year event using this methodology. Council staff also recalculated the load increases associated with these temperature deviations. Slide 6 of "Pilot Capacity Standard for the NW" PowerPoint shows the resulting temperature deviation versus load increase correlation for both summer and winter months.

B Pilot Capacity Standard Targets and Methodology

John then went onto describe the total additional load (refer to slide 8), which would need to be served in a more, or less severe, cold snap or heat wave. However, in developing a capacity resource adequacy standard, you also need to account for additional resources (above normal) that might be available to meet extreme temperature loads. Because the Federal Columbia River hydro system can be set up to produce an additional 2,300 MW in the winter without violating fish constraints, a case can be made that there are significant additional resources available when needed to meet cold snap loads. The July 24th event showed that BPA operated the FCRPS to make approximately 1,500 MW of additional sustained peaking capacity available in a summer heat wave event. John assumed an additional 4,000 MW available in the winter (3,000 MW out-of-region surplus capacity plus 1,000 MW additional sustained hydro peaking capacity—this is a conservative extrapolation from the BPA analysis showing an additional 2,300 MW of FCRPS capacity available); and 1,000 MW in the summer, which again is a conservative estimate of additional sustained hydro peaking capacity if the FCRPS is set up to meet loads in a heat wave. Analyses presented in previous meetings suggest a significant increase in non-Federal hydro is also achievable in a cold snap or heat wave event. Based on these assumptions of both increased loads and resources in cold snaps and heat waves, the suggested pilot planning reserve margins are 22% and 12% in the winter and summer, respectively. The Technical Committee generally appeared comfortable with these targets with the exception of Rod, who stated that he still questions whether 3,000 MW would be available from California.

There was quite a bit of discussion on how regional capacity reserves should be calculated (refer to slide 14). In the wintertime, it may be reasonable to assume the uncontracted IPP generation is available to the PNW because California would not be competing for these resources at that time. However, in the summer, it may not be reasonable to count the uncontracted IPP generation because California is competing for these resources. A number of participants questioned using a 30% capacity factor for wind in the Table on slide 14. BPA's data on July 24th shows a 15% capacity factor over 10 hours. Clint described an assessment Avista performed of regional wind availability. Over a 10 hour per day, 5 day sustained peaking period, a 20% capacity factor may be supportable. However, Clint did state that for their individual utility, they would assume a 10% capacity factor as the contribution of wind toward meeting peak loads because an individual utility cannot count on the diversity of resources available to the Region. The Technical Committee agreed on a 15% capacity factor for now.

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