West of Cascades North Path Curtailment and Congestion Management Lessons Learned

Date: October 5th, 2010

Prepared by:

Richard Becker – TES
Ron Rowe – TF
Steve Hitchens – TOT
Susan Millar – TS
Allen Chan – LT
Kristine Bartlett – PGSP
Thien Do – TG

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Executive Summary

The following report documents the events surrounding the West of Cascades North (WOCN) path curtailments and related congestion management actions from May 18 – May 21 and the lessons learned from those events. It also identifies reported impacts to marketers, Bonneville Power Administration (BPA) Transmission customers, and concerns regarding regional fish programs.

At the request of the BPA's Transmission management, a team was convened to provide an independent report on the events which were the causal factors, how BPA responded, the impacts of the events, and possible areas of improvements.

The review confirmed that during this event, the reliability of the Transmission System was maintained, no load was lost, and Biological Opinion objectives were met.

Causal Factor Identification

The team identified the emergency outage of the Olympia – Grand Coulee line coinciding with the planned outage of the Echo Lake – Monroe line from May 17 – 21 as the primary causal factor in lowering the WOCN System Operating Limit (SOL), also referred to in this report as path capacity or Operating Transfer Capacity (OTC). That condition, combined with low cost generation from the East displacing west–side thermal generation lead to high East–West flows on the WOCN that exceeded the path SOL. This SOL exceedance triggered redispatch, curtailments and actions that stopped hourly sales to return the path flows under the SOL.

Effect on Transmission Availability

The impacts of the planned outages for the Olympia – Grand Coulee line and the Echo Lake – Monroe line and the emergency outage for the Olympia – Grand Coulee line are included in the Transmission Availability metric. The desired outcome of the Transmission Availability metric is to have no control chart violations. Control charts are statistically–based graphs which illustrate the natural range of variability in performance, based on 10 years of historical data (FY97–FY07). The Availability data represents an average of more than 200 lines. FY10 2nd quarter data for Transmission Availability was 98.9% (target = 98%). The effect of any one or two outages (of a few days in duration) on the Transmission Availability statistic is very minimal.

SOL Relief from Redispatch, Curtailment and Stopped Sales

On May 18, Dispatch asked and Power Services agreed to redispatch 200 MW from the Upper Columbia Projects to the Lower Columbia Projects for hour ending (HE) HE8 and HE9. On May 19, Dispatch asked and Power Services agreed to redispatch 210 MW from the Upper to the Lower Columbia Projects for HE8–13. For HE14, Power Services agreed to redispatch only 130 MW to accommodate fish migration. During the combined outage, curtailments were implemented in only 4 hours. On May 18, Dispatch implemented iCRS for 300 MW of relief for each hour and iCRS curtailed: 770 MW for HE9; 717 MW for HE10, and 777 MW for HE11 to get the requested relief. On May 19, Dispatch implemented iCRS for 200 MW of relief and iCRS curtailed 354 MW for HE 17 for the requested relief. After the stop sales request was implemented, the number of new requests that were refused included: 166 requests on May 18; 355 requests on May 19; and 242 requests on May 20.

DSO216 Curtailments

On May 19 and 20, greater than 90% Wind INC reserves were deployed, resulting in curtailment of transmission schedules for wind generators. The DSO 216 curtailments ranged from 336 to 365 MW for each hour of curtailment, and were normal DSO 216 curtailments.

Conclusions and Recommendations

The areas that were reviewed by the subject matter experts (SME) for possible improvements included:

1. Finding: A conductor–to–ground clearance problem discovered during a working line patrol inspection was not addressed in a timely manner. During a routine Working Patrol inspection in November 2009, a conductor–to–ground clearance inconsistent with the National Electrical Safety Code (NESC) was identified, conveyed to the Transmission Line Maintenance (TLM) Foreman III at the time, and documented in Transmission Line Maintenance Applications (TLMAPPS), a database for recording transmission line maintenance information. The acting TLM Foreman III on May 12 stated that the clearance problem was discovered in November 2009 but the subsequent analysis erroneously determined that it was not an urgent problem. Per the May 12request of the acting TLM Foreman III, the line design engineer verified the conductor position by analyzing the Light Detection and Ranging (LiDAR) files created from data collected in 2007.

Areas for improvement:

a. Conduct or coordinate a review of TLMAPPS entries to identify or verify if other clearance issues are outstanding.

   - Accountable VP: Juj – TP
   - SME: Batchelor – TPO
   - Completion Date: 10/1/10
   - Metric: % of database analyzed and verified
   - Target: 100% of database analyzed

b. Establish procedures that provide on–going timely verification of significant (safety and reliability compliance) TLMAPPS inputs; requires IT support.

   - Accountable VP: Juj – TP
   - SME: Batchelor – TPO
   - Completion Date: 7/1/11
   - Metric: % of drop down menu completed
   - Target: 100%
   - Metric: % of training completed
   - Target: 100%

c. Develop a methodology to analyze LiDAR information to identify clearance violations. The methodology should include resource needs, risks, benefits, costs, etc

   - Accountable VP: Bekkedahl – TE
   - SME: Staats – TEL
   - Completion Date: 3/1/11
   - Metric: Methodology completed
   - Target: 100%

2. Finding: The initial WOCN study process did not consider the impact of the Echo Lake–Monroe line outage. As a result, the impact to the WOCN path was not identified until the May 14 studies captured the combined outages of the Echo Lake–Monroe line and the Olympia–Grand Coulee line.

   Areas for improvement:

   a. System Operations will review current study processes and methodology for N–2 contingencies (as per the WECC regional difference) to assure that all appropriate equipment which could impact an SOL is considered and to revise and update as necessary. The WECC Reliability Coordinator methodology requires analysis for N–1 contingencies

      - Accountable VP: Thomas – TO

- SME: Elizeh – TOT
- Completion Date: 10/1/10
- Metric: WOCN reviewed
- Target: 100%
- Completion Date: 10/1/11
- Metric: All remaining identified internal paths reviewed
- Target: 100%

3. Finding: The normal BPA SOL study process uses conservative assumptions to determine limits that will be reliable for variations in system conditions. Using real–time system conditions resulted in a less restrictive WOCN limit.

   Areas for improvement:

   a. Lead time to update study model (receipt of notice emergency outage to completion of SOL studies) was very short. Studies reflecting the existing conditions can be produced using the State Estimator model. Study Engineers need to be able to use State Estimator models to quickly determine more accurate SOLs for unplanned and emergency outages. Need to complete the study tool improvement project; R & D funding required.

      - Accountable VP: Thomas – TO
      - SMEs: Gronquist – TOT, Tuck – TOT, Karasev – TOS
      - Completion Date: 12/1/10
      - Metric: Plan developed to accelerate study tool improvement project
      - Target: 100% Complete
      - Completion Date: Phased dates defined by plan. Full implementation will take several years.
      - Metric: Study tool improvement project completed
      - Target: 100% operational

4. Finding: The May 14, 2010 study with both Olympia – Grand Coulee and Echo Lake – Monroe lines out of service resulted in an SOL that was lower than previously expected. There were gaps in the communication of the impacts internally and externally. The WOCN actual flow on May 17th exceeded the initial studied WOCN SOL, which was not implemented until May 18. However, the WOCN actual flow on May 17 did not exceed the revised SOL that was determined from studies later in the week.

   Areas for improvement:

   a. Review internal procedures (e.g., DSO148) and revise as appropriate, to ensure timely communication to appropriate internal organizations of reduced SOLs and provide refresher training for implementation of the procedures. Review will focus on communications between study engineers and dispatch, between dispatch centers, to executives and links to external communications.

- Accountable VP: Thomas – TO
- SME: Ellison – TOD, Snodgrass – TOV, Elizeh – TOT
- Completion Date: 8/15/10
- Metric: Procedures reviewed and revised
- Target: 100%
- Completion Date: 11/30/10
- Metric: Training completed
- Target: 100%

b. Outages, including unanticipated combined outages, may significantly reduce path SOLs and impact the market. Define threshold criteria to identify at what point urgent and emergency outages with impacts to SOLs are communicated externally, and develop protocols and procedures to timely communicate such impacts to appropriate staff and management. In addition, develop protocols and procedures to provide timely notice to customers if: 1) urgent and/or emergency outages are expected or known to significantly reduce path SOL; and 2) mitigation measures (e.g., curtailments or stop sales) are implemented. Provide training to staff and management for implementation of the procedures.

- Accountable VPs: Ehli – TS
- SME: Fitzsimmons – TSE; Holden–Baker –TSS; Manary – TSR; Millar – TS; Ellison – TOD; Hunter – TFB
- Completion Date: 11/1/10
- Metric: Reporting criteria defined; Process and procedures in place; Training provided
- Target:100%

5. Finding: On May 12, the conductor–to–ground clearance problem on the Olympia–Grand Coulee line prevented return of the line to service for safety reasons, and Munro Control Center approved extending the outage as an emergency outage. During the discussions between Dispatch and field personnel on the plan for repair of the Olympia – Grand Coulee line there were no indications to Dispatch of any additional derates to Path SOLs nor any market concerns with the line out of service. As a result, work was approved to commence during normal work hours the following week (May 17). Not until subsequent discussions on May 19 between Dispatch and field personnel were the market impacts and the urgency to restore one of the two lines to service conveyed to the field personnel.

Areas for improvement:

a. Establish communication protocols that clearly communicate the urgency to return a line to service when an outage is known to have an extraordinary impact on the market, and provide training on protocols.

- Accountable VPs: Thomas –TO
- SME: Ellison – TOD & Rowe – TF
- Completion Date: 8/1/10
- Metric: % of protocol completed
- Target: 100%
- Completion Date: 9/1/10
- Metric: % of training completed
- Target: 100%

6. Finding: Dispatch requested Stop Sales for only Non–Firm sales. Dispatch subsequently requested Stop Sales for new Firm requests. New hourly Firm requests, including redirect requests, contributed to additional Firm curtailments on May 18 in HE10 and HE11. Customers had difficulty finding posted information regarding Stop sales on the BPA OASIS and web page.

Areas for improvement:

a. Revisit and revalidate procedures for implementing Stop Sales and provide refresher training internally.

- Accountable VPs: Ehli – TS
- SME: Holden–Baker–TSS, Ellison–TOD, Snodgrass–TOV
- Completion Date: 8/1/10
- Metric: Procedures reviewed and updated as needed
- Target: 100%
- Completion Date: 9/1/10
- Metric: Training provided to Transmission Schedulers, Account Executives, and Transmission Dispatchers
- Target: 100%

b. Establish protocols and procedures to assure internal consistency when posting information related to Stop Sales (what is posted and where to post information), including procedures for notifying customers that sales are stopped (e.g., email exploder); provide training internally.

- Accountable VP: Ehli – TS
- SME: Manary–TSR; Holden–Baker–TSS
- Completion Date: 8/1/10
- Metric: Complete protocols, procedures, and training
- Target: 100%

c. Provide customer training on the Stop Sales Tool, including features of the tool, and where to look for postings when the tool is implemented.

- Accountable VP: Ehli – TS
- SME: Manary–TSR, Holden–Baker–TSS
- Completion Date: 9/1/10
- Metric: Customer training complete
- Target: 100%

7. Finding: The Capacity desk does not post updated outage information in the real–time day. In addition, customers had difficulty finding outage information on the BPA Website. The Outage and Interruption Page on the BPA Website does not have a separate listing for the WOCN path. Outages for the WOCN path can be found on the OASIS Outage page for specified days.

   Areas for improvement:

   a. Establish a separate listing for all missing BPA monitored flowgates/paths on the Outage and Interruption Page under "Known Constraints".
      - Accountable VPs: Ehli – TS
      - SME: Manary–TSR, Millar–TS, Ellison–TOD
      - Completion Date: 10/1/10
      - Metric: Add all missing BPA monitored Flowgates to the Outage & Interruption Page
      - Target: 100%

   b. Changes from current posting practices will require significant modifications to procedures, systems, and includes OASIS and BPA website. Complete a cost benefit analysis for improved access to outage information. Changes from current practices would require significant modifications of the OASIS and BPA website.
      - Accountable VPs: Ehli – TS
      - SME: Manary–TSR
      - Completion Date: 7/1/11
      - Metric: Cost benefit analysis complete and decision made.
      - Target: 100%

   c. Review procedures and protocols to determine consistency of posted outage information; and provide training for locating outage information to internal and external parties.

- Accountable VPs: Ehli – TS
- SME: Holden–Baker–TSS
- Completion Date: 10/1/10
- Metric: Procedures reviewed, and internal and external training provided
- Target: 100%

8. Finding: BPA plans the network transmission system for long–term commitments, and schedules maintenance outages to maximize transmission flowgate availability to accommodate these long–term commitments. BPA does not have an hourly ATC methodology for its Network flowgates. Without an hourly ATC methodology for the Network flowgates, requests for hourly reservations and hourly schedules are unlimited and are a major contributor to the congestion when the flowgate/path SOL is exceeded. BPA can use the Stop Sales Tool to stop new firm and non–firm reservations that have a non–de minimis impact on a specified path, but this an inflexible and imprecise tool, (e.g., the tool is only on or off and has other limitations).

   Areas for improvement:

   a. Establish hourly ATC Methodology. An hourly ATC methodology for Network flowgates will be established when BPA implements the NERC ATC methodology.

      - Accountable VP – Ehli – TS
      - SME: Gillman–TSSP; ATC Project
      - Completion Date: Current effective date for NERC ATC standards is 4/1/11. Planning for implementation is underway.
      - Metric: Methodology in place
      - Target: 100%

   b. Engage Customers in a discussion of how to resolve the conflict between BPA's obligation to plan and maintain the transmission system for long–term commitments and the customers' use of the transmission system for short term and hourly transactions.

      - Accountable VP – Ehli – TS
      - SME: Fitzsimmons – TSE
      - Completion Date: 1/1/11
      - Metric: Pro
      - Target: 100%

9. Finding: A major customer complaint was that the stop sales tool does not accept redirect requests. BPA permits the netting of redirect requests in its current ATC methodology; however, this policy is not consistent with Order 890 requirements.

The Stop Sales Tool was designed to meet Order 890 requirements and does not allow the impact of the original reservation to be netted against the impact of a new redirect reservation. Therefore, all new redirect requests with non–de minimis impact on the WOCN path were refused.

Areas for Improvement:

a. Determine whether practice of permitting the netting of redirect requests is allowable under new NERC ATC standards. If allowable, perform analysis, including cost/benefit, to determine the best approach to allow the netting of redirect requests when the stop sales tools are used.

- Accountable VP: Ehli – TS
- SME: Gillman–TSSP; ATC Project
- Completion Date: Current effective date for NERC ATC standards is 4/1/11. Planning for implementation is underway.
- Metric: Decisions made on stop sales and redirect netting are complete
- Target: 100%

10. Finding: The iCRS curtailments are not as precise as they might otherwise be. The iCRS tool is not updated for real time conditions, including updates of the Federal Columbia River Power System (FCRPS) generation dispatch data. Many interchange schedules are tagged system–to–system, and tags within the BPA Balancing Authority also lack granularity. An hourly ATC methodology with updated real time operating conditions and FCRPS dispatch patterns, and modifications of BPA's processes and procedures to require more granularity (e.g., redispatch protocols, zonal scheduling or other specificity) would likely allow BPA more visibility of the system limitations in real time. BPA also needs to: 1) separately account for the FCRPS contribution for BPA's Automatic Generation Control (AGC) system (e.g., for reserves, regulation, imbalance energy, etc.), losses, and other similar uses in the ATC methodology; and 2) consider modifications to internal processes and procedures for Discretionary Redispatch.

Areas for Improvement:

a. Decide timing for updates to NERC ATC System Model (e.g., hourly); review and determine if more granularity is required for processes and procedures for the NERC ATC methodology to implement curtailments and redispatch.

b. Decide appropriate accounting for FCRPS supplied AGC, losses, and other similar uses in the NERC ATC methodology.

- Accountable VP: Ehli –TS
- SME: Gillman–TSSP; ATC Project

- Completion Date: Current effective date for NERC ATC standards is 4/1/11. Planning for implementation is underway.
- Metric: ATC project decision regarding more granularity complete
- Target: 100%

c. Review and modify, as appropriate, internal processes and procedures for Discretionary Redispatch

- Accountable VP: Ehli –TS; Thomas – TO
- SME: Fitzsimmons–TSE; King–TSP; Ellison – TOD; Connolly – PGS
- Completion Date: 1/1/11.
- Metric: Procedures are in place
- Target: 100%

11. Finding: Customers have little understanding of the iCRS curtailment calculator. The iCRS tool only implements curtailments, and only curtails tagged scheduled transactions that have a greater than *de minimis* impact (non–*de minimis* impact) on the identified flowgate. Presently, the iCRS tool cannot: 1) implement redispatch to any Network Integration Transmission Service (NT); 2) quantify the non–*de minimis* impact exposure NT transactions (both Federal and non–Federal resources) have on a flowgate; and 3) account for untagged deliveries of the FCRPS to NT customers.

    Areas for Improvement:

    a. Identify the impact of NT transactions on congested flowgates; establish protocols and procedures to redispatch Designated Network Resources (both Federal and non–Federal) for NT service; and develop automation to implement NT redispatch to Federal and non–Federal Designated Network resources contemporaneous with Firm Point to Point curtailments.

    b. Identify untagged uses of the FCRPS that affect network flowgates, and define and implement a proxy in iCRS for untagged NT transactions from the FCRPS.

    c. Provide customer training on iCRS curtailment calculator, including how dynamic schedules are curtailed.

- Accountable VP: Thomas –TO
- SME: Simons – TOK
- Completion Date: 12/31/10
- Metric: untagged transactions and network redispatch implemented in iCRS, and customer training completed.
- Target: 100%

Reported impacts to the FCRPS and BPA's Customers

The primary impact reported by Customers was a financial impact related to short term market transactions. Customers were unable to access hourly transmission service to deliver their short term market arrangements, which caused prices at the MID–C market to plummet. All loads were served. Congestion did not cause any hydro operations to spill or cause any violations of Biological Opinion objectives.

a. Several customers estimated lost revenues from May 18–20.

- Many customers (e.g., Power Services (PS), TransAlta, Calpine, Powerex, Portland General Electric (PGE), Puget Sound Energy (PSE), Snohomish, Douglas, Avista, Tacoma, Seattle City Light (CSL)) reported that they were directly limited in their ability to deliver their daily market commitments due to interruptions caused by curtailments and restrictions on new hourly sales, especially redirect requests.

- Many customers (e.g., TransAlta, Calpine, PSE, PGE) reported that they were not able to maximize economic dispatch options, and instead had to operate thermal projects that were otherwise idled or out for maintenance.

- In some cases customers (e.g., Tacoma, SCL, Powerex, PS), reported that the combination of curtailments and limits on new sales forced to rely on power from their hydro facilities, which affected economic operation and management of their river systems.

b. The Columbia Generating Station (CGS) reduced its output by 3500 MWh starting HE09 on May 20 through HE10 on May 21.

c. Due to the flow requirements into Priest Rapids for fish migration, PS was limited on how much generation could be reduced at Grand Coulee and Chief Joseph and was not able to accommodate all of the discretionary redispatch requests.

d. Fish studies were underway at Chelan and the operators were concerned that they were at risk for passing water in violation of those studies. There was no violation.

e. Several customers (e.g., Powerex, PGE, Snohomish) expressed concern that curtailments were not implemented consistent with NERC priorities, and that new requests seemed to impact the WOCN Path. All curtailments were implemented in NERC priority order.

Secondary Areas of Concern

While not a root cause to this event, the limited availability of warehouse inventory to respond to an emergency situation and the lead time to acquire and transport material contributed to the duration of the outage.

Areas for improvement:

A. Review and make recommendations on the appropriate level of emergency inventory.

- Accountable VP: Callaghan – NS
- SME: Ware – NSL
- Completion Date: 3/1/11
- Metric: % reviewed
- Target: 100%

Other Contributing Factors

1. In order to maximize system reliability within the region while balancing the need to complete maintenance and construction workload, several outages were scheduled back-to-back or simultaneously.

2. A large amount of work was scheduled during each line outage window and little allowance in the work plans to address unanticipated events or conditions.

3. The site assessment lead time delayed the start of making repairs during the Olympia-Grand Coulee emergency outage.

4. A Management directed safety stand down and review of a fatal accident delayed the start date and reduced the number of days to complete work during the Olympia-Grand Coulee planned outage. The emergency outage would have occurred regardless of the delay, but the duration of the outage may have been shorter.

Glossary

Affected Path – Any managed path affected by a Significant Equipment outage.

Available Transmission (or Transfer) Capacity (ATC) – The transfer capability remaining in the physical transmission network for further commercial activity over and above already committed uses.

BPA Network (Integrated Network) – The Network is the segment of the Federal Columbia River Transmission System (FCRTS) for which the transmission facilities provide the bulk of transmission of electric power within the Pacific Northwest.

Capacity Plan – Managed path(s) transfer capacity(s) available for sale to transmission and power marketers.

Constrained Path – An intertie or cutplane (a line or group of lines) on which power flow is monitored to ensure reliable operation of the transmission system. A managed path that has capacity reduced due to system operating conditions and/or a Significant Equipment outage.

Curtailment – Either the real–time actual reduction of sold and unsold (ATC) capacity or a reduction of sold and unsold (ATC) capacity due to a studied condition.

Emergency Outage – An outage that must be taken immediately to alleviate a safety or reliability problem (there is no time to plan).

Equipment Outage – The removal of power system equipment from service that affects the operation or protection of the power system.

FCRPS – the Federal Columbia River Power System.

Network Integration Transmission Service (NT) – Service that allows an electric transmission customer to integrate, plan, economically dispatch, and regulate its network reserves in a manner comparable to that in which the transmission provider serves native load customers.

Nomogram – A set of monitored variables that can affect capacities on managed paths. These variables can include temperature, loading, and generation.

Northwest Power Pool (NWPP) – serves as a forum in the electrical industry for reliability and operational adequacy issues in the Northwest, through both the transition period of restructuring and the future. NWPP promotes cooperation among its members in order to achieve reliable operation of the electrical power system, coordinate power system planning, and assist in transmission planning in the Northwest Interconnected Area.

Open Access Same Time Information System (OASIS) – Internet web site where BPA posts outage and capacity plans, part of FERC's Open Access Transmission Tariff (OATT).

Operating Transfer Capacity (OTC) – The amount of power that can be reliably transmitted through a transmission path given current or forecasted system conditions.

Operating Bulletin No 19 – Document containing Significant Equipment Outage requirements.

Outage Scheduling – The planning process by which power system equipment is scheduled for removal from service.

Path Capacity – The planned level to which managed path(s) can be loaded on any outage plan for a given day. On rated paths, this is the same as the daily OTC.

System Operating Limit (SOL) – The value of the path (such as MW) that satisfies the most limiting of the prescribed operating criteria for a specified system configuration to ensure operation within acceptable reliability criteria.

1.0 Description of Events

1.1 Investigation Team and Contents of Report

To understand why the WOCN curtailments occurred and the impacts, the Transmission Managers decided to structure the team with team leads responsible for collecting data from each organization involved. The work assignments were as followed:

Richard Becker – Team lead for Engineering perspectives
Ron Rowe – Team lead for Field Services perspectives
Steve Hitchens – Team lead for System Operations perspectives
Allen Chan – Attorney – Adviser
Susan Millar – Team lead for Sales & Marketing perspectives
Kristine Bartlett – Team lead for Power Services perspectives
Thien Do – Lessons learned coordinator
Katie Davis – Assistant Coordinator

The investigation was initiated on May 26 per the request of the Transmission Services Senior Vice President. Data gathering activities were concluded on June 11. This report documents the findings of the investigation team through interviews with people with first hand knowledge of the events, reviews of logs, current policies, standards and procedures, and review of customer input on market impacts.

1.2 Significant Equipment Outages (Planned, Urgent, Emergency)

The Northwest Power Pool (NWPP) Operating Manual, Section H, and BPA Operating Bulletin 19 (OB19) lay out the coordinated outage planning process and the significant equipment included in that process for NWPP members. The benefits of this process include:

- local area generation consideration (generation restrictions due to an outage);
- load service and path capacity considerations;
- communication with affected/interested parties (including marketing, path owners and neighboring utilities);
- enabling all *necessary* outages while maximizing facility capacity; and
- providing predictability for customers and owners/operators of the system.

BPA follows the NWPP Outage Coordination Process, which requires submittal of requests for planned outages of significant equipment a minimum of 45 days prior to the

month in which the outage is proposed. Significant equipment, when taken out of service, may contribute to reduction of path capacity to assure reliable operation on a constrained path. This includes outages that alone might not affect reductions to capacity, but under credible conditions, in combination with others, could have an effect.

The NWPP Outage Coordination Process during this 45–day period set the following steps:

- NWPP members submit proposed significant equipment outages at least 45 days prior to the outage month.

- BPA as the facilitator of the process for the NWPP posts on BPA's website an initial outage plan of unstudied outages and the estimated path impact about 44 days prior to the outage month, and emails a notice to WECC Reliability Coordinator (RC), Transmission Owners, and Transmission Operators announcing the initial outage plan is posted. A separate email is sent to the BPA Transmission Capacity Forum, which includes marketers and the public.

- Public review and comment of the initial outage plan about 37 days prior to the outage month (Market Visibility).

- Approximately 36 days prior to the outage month, the Transmission Owners/Operators meet at the monthly NWPP Outage Coordination meeting (tele–conference) to consider comments and concerns received.

- The Coordinated outage plan is posted on BPA's web site and an email is sent to the WECC RC, Transmission Owners, and Transmission Operators about 35 days prior to the outage month. A separate email is sent to the BPA Transmission Capacity Forum, which includes Marketers and the public.

- The final outage plan is posted on BPA's web site and an email is sent to the WECC RC, Transmission Owners, and Transmission Operators 30 days prior to the outage month. A separate email is sent to the BPA Transmission Capacity Forum, which includes marketers and the public.

NWPP outages fall into one of three categories:

- Planned outage – An outage that is coordinated through the NWPP Outage Coordination Process and is included the final outage plan for the month.

- Urgent outage – An outage that must be taken before the next outage planning cycle NWPP Outage Coordination Process but is not an emergency.

- Emergency outage – An outage that must be taken immediately to alleviate a safety or reliability problem which is requested at the time of need from the Real–Time System Dispatcher.

In addition, BPA's Transmission system is operated within a hierarchy of three criteria by order of importance:

1. Safety of personnel and the public is never jeopardized in deference to revenue;

2. Reliability is never jeopardized for revenue; and

3. BPA's Transmission revenue is secured.

1.3 Outages affecting the WOCN Path

Planned outages that affect a path are approved using the following guidelines:

- Outages that need to be taken during heavy loading conditions on a constrained path should be coordinated to minimize curtailments during the peak transmission usage period of the day.

- The impacts that weather or fire may have on transfer capability during an outage are considered.

- Generator outages that may impact transfer capability or the ability to load a path are considered when planning outages.

1.4 Description of Olympia – Grand Coulee Planned Outage

The Olympia – Grand Coulee planned outage was initially posted in the final outage plan for May on April 5. The outage allows for maintenance work on the 287/230kV Bank 3 at Olympia Substation, insulator replacements on the line, and replacement (or shunting) of one hot splice at structure 69/3. The WOCN path SOL calculation showed 7260 MW – 9560 MW with all lines in operation. The Olympia – Grand Coulee outage reduced the WOCN path SOL to 6880 MW – 9110 MW. BPA had an agency–wide safety stand down on May 10, so the start date for the outage was pushed back from May 10 to May 12. The line was taken out of service on May 12 at 0730 and was scheduled to be back in service by May 14 at 1500.

1.5 Description of Olympia – Grand Coulee Emergency Outage

It is possible for any outage that additional problems may be identified that will require additional work. In these situations, the TLM Foreman III consults with other organizations to evaluate the situation and discuss how to proceed. On May 12, the acting TLM Foreman III reviewed his work plan and the TLMAPPS database and found an entry flagging a possible ground clearance inconsistent with the NESC in the Ahead–on–Line (AOL) span from structure 70/2 (AF343). The NESC minimum ground clearance for a 287 kV line is 23 feet at Maximum Operating Temperature (MOT).

This entry was made during a routine Working Patrol inspection in November 2009. The TLM Foreman I conducting the Working Patrol inspection identified a 13–foot conductor–to–ground clearance problem, conveyed this information to the TLM Foreman III, and documented the information in TLMAPPS. BPA's Working Patrol guidance requires the assumption of a 10 foot margin ("adder") subtracted from the actual conductor–to–ground clearance to account for conductor sag under high load and temperature conditions. The TLM Foreman III mistakenly believed the ground clearance was 23 feet, because he believed the reported 13-foot clearance included the 10-foot adder. The TLM Foreman III checked the Plan & Profile drawings and concluded that 23 feet was within the minimum required conductor–to–ground clearance.

On May 12, the acting TLM Foreman III called the Transmission Engineering Group (Engineering) to discuss the conductor-to-ground repair issue. At Engineering's request, the acting TLM Foreman III collected more site data. Engineering then determined that the pronounced deflection of the insulator strings at structure 70/1 and structure 70/3 suggested structure. 70/2 had moved and additional information was needed to design a fix. Engineering verified the conductor position by analyzing the LiDAR files created from data collected in 2007. The conductor appeared to be about 12ft. from the ground on the high side of the Right–of–Way (ROW) near a knob about 2/3 of the way along the span (see Figure 1). At this location, the conductor should be at least 30 feet to 35 feet above the ground under typical operating conditions to allow 25 feet to 26 feet of operating conductor–to–ground clearance under MOT.

Figure 1 – Olympia _ Grand Coulee Str. 70/2 looking Back on Line

Engineering discussed the clearance problem with Technical Operations. Technical Operations informed Engineering that the line was out for maintenance work and the clearance issue would prevent the line from being returned to service until the problem is fixed.

Munro Control Center (MCC) Dispatch was notified on May 12 of the conductor–to–ground clearance problem and an emergency outage request for the Olympia – Grand Coulee line was submitted. MCC Dispatch informed the acting TLM Foreman III of the emergency outage approval.

On May 17, a team of SMEs from Engineering met with the Acting Covington TLM Foreman III, the Olympia TLM Foreman III, the Covington District Manager, and the Covington TLM crew at the site. Field investigation confirmed that structure 70/2 moved 1 to 2 feet out of plumb. The working point elevations at the tower footing stubs moved downward about 3 inches at the 2 western stubs and about 6 inches at the northeastern stub. All measurements were made relative to the southeastern stub. The findings suggested settling and shifting of the tower foundations. The earth movement, however, did not appear to be continuous and the tower showed no significant member deflection. Structure 70/2 and its foundations were deemed sufficiently stable to allow re–tensioning of the conductors so that the conductor–to–ground clearance problem could be corrected.

The plan was to have the design work to correct the conductor–to–ground clearance problem for all three conductors completed on May 18 and materials delivered on site by May 20. Some parts were not available from stock and had to be fabricated by BPA's shops. The Acquisition Analyst had to make phone calls around the regions to get other parts. All materials arrived, with some being hand delivered after hours, to the job site by May 19.

In addition to the conductor–to–ground clearance problem, Engineering worked with the Covington TLM crew to develop a plan to correct a hot splice (heating due to excessive resistance in the connections) on one of three phases on the Olympia – Grand Coulee line. The Covington TLM crew already had a splice shunt on hand and they had planned on using this shunt on the hot splice earlier on this year but the conditions of the access roads prevented them from shunting the splice at that time. TLM's original plan was to shunt only the hot splice. However, Engineering recommended shunting the splices on the other two phases as a preventive measure to prevent possible future problems. As a result, the Covington TLM crew had to acquire two additional splice shunts in order to complete this work. As explained below, however, due to discussions with MCC Dispatch, the decision was made by the Acting TLM Foreman III, in consultation with Engineering, to postpone the work on the other two phases.

On May 18, Dittmer Dispatch told the Covington TLM crew that the Olympia – Grand Coulee line needed to be energized as–soon–as–possible. Field Management responded that they were still awaiting parts, and they anticipated having the work completed by May 21.

MCC Dispatch called the acting Covington TLM Foreman III again on May 20 to determine the earliest date Olympia – Grand Coulee could be returned to service. At this point, the decision was made to limit the work to just shunt the hot splice phase. The hot splice shunt work was completed on May 20. The Olympia TLM crew joined the Covington TLM crew and finished the work to correct the ground–to–conductor clearance problem on the most problematic phase in the afternoon of May 21. This decision was made by the Acting TLM Foreman III, in consultation with Dispatch. Once it was decided that the other two phases could be re–tensioned at a later date, Dispatch returned the line to service on May 21 at 2018.

An urgent outage was later taken on June 1–4 to complete the work on the other phases.

1.6 Description of the Echo Lake – Monroe Planned Outage

The Echo Lake – Monroe line planned outage from May 17–23 was initially posted in the final outage plan for May on April 5. The planned outage was for the replacement of insulators and spacer dampers on the line, and removal of danger trees. At the time, the WOCN path SOL studies did not evaluate the effect of the Echo Lake – Monroe line outage on the WOCN path. This outage was assumed to affect only the Northern Intertie. The line was taken out of service on May 17 at 0800 and was to be back in service by May 22 at 1430. BPA issues advisories to customers in the Puget Sound area and customers using the Northern Intertie (PSANI Advisories) if outages are likely to affect deliveries from the south and east into and through the area. Due to the Echo-Lake-Monroe line planned outage, BPA issued PSANI Advisories on May 13, 14, 17 and 18 alerting customers to reductions to Northern Intertie SOL that were expected to be below long–term Northern Intertie commitments for May 17, 18, 19, 20, and 21. In response to a PSANI Advisory, Puget Sound area customers are expected to plan to operate local generation or arrange for imports from within the PSANI bubble or from the north instead of scheduling imports from other areas south and east of the Puget Sound area.

Due to concerns about the combined effect of the Echo Lake – Monroe line planned outage with the Olympia – Grand Coulee line emergency outage on the WOCN path, an additional study was conducted on May 14. The Echo Lake – Monroe planned outage was planned to avoid overlaps with outages taken by Seattle (cable outages) and Puget (Sedro Woolley facilities), and could not be rescheduled.

1.7 Additional Background Information from Field Services

Due to a request from Dispatch caused by other system outages, the Covington TLM crew ended up with outages on both the Raver – Covington #1 500kV line and the Olympia – Grand Coulee line in the same week. A significant amount of work (insulator and conductor work on both lines, transformer work on the Olympia – Grand Coulee line, and riser and Personal Communication System (PCS) work on the Raver – Covington line) was scheduled to be performed. The Acting Covington District TLM Foreman III's perception was that the crew would be able to manage the work scheduled to be done for both outages. This was before he became aware of the problem with the sagging conductor on the Olympia – Grand Coulee line.

The Acting TLM Foreman III at Covington is normally the crew's TLM Foreman I, and is acting because the TLM Foreman III position is currently vacant due to the permanent TLM Foreman III accepting a position in Redmond, Oregon. The Acting TLM Foreman I has been with BPA since November and has very little experience working on the transmission system, especially on steel structures. The crew, for the most part, has limited time on the BPA system. Therefore, the Acting TLM Foreman III was very dependent on guidance from Engineering to assist him in finding the proper resolution to the sagging conductor problem.

Since the impacts of the combined of the Olympia – Grand Coulee line emergency outage and the Echo Lake – Monroe line planned outage were unknown, there was no communication to the Acting TLM Foreman III, that the outages would have any significant system impacts when the outage was approved. The Covington Chief Operator III made initial inquiries on May 14 about how extended the Olympia – Grand Coulee line emergency outage would have an effect on the market. The Transmission Policy group focused on impacts to BPA transmission sales rather than on the market and indicated a low probability of lost revenue.

As will be discussed in later sections, these combined outages had a detrimental effect on the energy market. In reviewing several discussions between dispatch and field personnel during the week of May 17– May 21, it is clear that there were considerations about what work should be done when utilizing overtime and using additional help to accomplish the work by Friday, May 21. However, the urgency of the market problems caused by these outages were not timely communicated to field personnel. Therefore, field personnel did not consider an alternative approach to the conductor-to-ground problem.

On the afternoon of May 18th, after the market impacts of the reduced WOCN SOL were realized, Dispatch considered cancelling the Echo Lake – Monroe line planned outage. The Echo Lake – Monroe line planned outage is a significant outage that impacts the Northern Intertie SOL. Dispatch worked with the Seattle and Puget utilities, pursuant to the PSANI advisories, to increase their internal generation during the timeframe of the Echo Lake – Monroe outage. Increased Puget Sound Area generation would also reduce the east to west loadings on the WOCN path. Dispatch was concerned that it would be difficult to re–schedule the Echo Lake – Monroe outage before the Summer season and during the upcoming scheduled outages by other Puget Sound utilities (Seattle cable outage and Puget Sedro Woolley facilities outages). Dispatch decided: 1) not to cancel the Echo Lake – Monroe outage because the maintenance work was required to ensure public safety and transmission system reliability; and 2) to focus efforts on returning Olympia – Grand Coulee to service. The maintenance work on the Echo Lake – Monroe line included insulator replacement, spacer damper replacement, and danger tree cutting (the danger trees were those left after all trees that could be taken under a Hold Order had been removed). With all the other work planned in the Puget Sound area it was unlikely that another outage of the Echo Lake–Monroe line could be accommodated before the peak summer load period when the impacts of an unplanned outage on the SOLs (Northern Intertie and WOCN) and the market would be much greater.

1.8 Reduction in SOL

SOL studies that include the effects of planned outages are completed by Technical Operations and posted two weeks prior to the outage week. Unplanned and emergency outages are studied as needed and updated SOLs are coordinated with Dispatch and subsequently with Transmission Marketing & Sales and PS Hydro Operations.

With all lines in service, the WOCN path SOL is 7260 – 9560 MW for Spring and Summer seasons. In general, when ambient temperatures are at or below 68ºF, the

WOCN SOL is voltage stability limited (the higher value). At higher temperatures the SOL is limited by thermal problems (the lower value). Due to the uncertainty of the ambient temperature, the lower limits are posted. Software interpolates between those limits depending on the ambient temperature to determine the real–time SOL monitored by Dispatch. Studies indicated that the WOCN path SOL would be reduced to 6880 MW – 9110 MW with the planned Olympia – Grand Coulee outage. Studies for the Echo Lake – Monroe line planned outage only evaluated the impact on the Northern Intertie and not the WOCN path.

On Friday, May 14, due to the emergency outage of the Olympia – Grand Coulee line, Technical Operations conducted SOL studies on the WOCN path with both the Olympia – Grand Coulee and the Echo Lake – Monroe line out of service. The WOCN SOL range was determined to be 5980 MW – 6425 MW for this combined outage. The result was documented in a Study Limit Memo and sent to the Dittmer Outage Office at 1625. The Dittmer Outage Office delivered the Path Limit Notification to the Capacity Desk at 1630. The Capacity Desk staff had departed for the weekend before receiving the updated WOCN SOL. Due to an oversight, the Path Limit Notification was not adequately communicated to the Dittmer Senior Dispatcher, and was not picked up by a Senior Dispatcher until early Tuesday morning, May 18.

Notice #77375 was posted on the OASIS Outage page by the Capacity Desk on Monday, May 17 at 0652 with the updated WOCN SOL of 5980 MW to start on May 18 at 0000. WOCN SOL reductions were not implemented through Monday May 17th, even though the outages were underway.

The high loading on the WOCN path (i.e., approaching or exceeding path SOL) caused Technical Operations to conduct short–term studies from May 18 to May 20 in an effort to increase the WOCN path SOL. Technical Operations revised the base case model to determine if system conditions could be better represented at that time. Revised voltage stability studies showed increased reactive support available in the Puget Sound area which resulted in increasing the WOCN SOL to 5980 MW – 6650 MW on May 18 at 1205.

Additional studies were completed on May 19 at 1700. By revising the voltage stability studies to more accurately model the generation pattern in the Upper and Mid Columbia regions, the WOCN SOL was elevated to 5980 MW – 6881 MW.

Technical Operations reconfigured a saved case from the State Estimator (which models actual system conditions) and ran it through an off–line study program. The voltage stability results from this model showed more WOCN capacity by modeling the south–to–north flow conditions on the Northern Intertie. The original studies assumed a north–to–south flow on the Northern Intertie. The results were validated against a WECC developed seasonal base case model. On May 20 at 1600, a new WOCN SOL was set at 5980 MW – 7537 MW.

When the Olympia – Grand Coulee line returned to service on May 21 at 2018, the WOCN path SOL with the Echo Lake – Monroe line still out was adjusted to 7260 MW – 8042 MW.

On May 22 at 1430, the Echo Lake – Monroe line was returned to service. The WOCN path SOL with all lines in service was set at 7260 MW – 9560 MW.

A summary of the outage sequence SOLs is shown in the table below.

	Outage Type	Line Out	Line In	WOCN MIN SOL
Olympia – Grand Coulee	Planned Maintenance	May 12 (0730)	May 14 (1500)	6880 MW
Olympia – Grand Coulee	Emergency	May 14	May 21	6880 MW
Olympia – Grand Coulee + Echo Lake – Monroe	Emergency / Planned	May 17 (0800)	May 21 (2018)	5980 MW
Echo Lake – Monroe	Planned Maintenance	May 21 (2018)	May 22 (1430)	7260 MW
Olympia – Grand Coulee	Urgent	June 1 (0800)	June 4 (1500)	6880 MW

1.9 Studies to Maximize SOL for WOCN during the Combined Outages

The WECC seasonal base case models are evaluated and modified for each intertie and flowgate operational study. Conditions vary greatly, and at times, without advance knowledge. Study assumptions will not always capture all the variables. For the combined Olympia – Grand Coulee and Echo Lake – Monroe outages, Technical Operations deployed additional study staff who were able to identify several sets of modeling changes that more accurately reflected the current state of the system. Subsequent studies produced improved SOL at each step. This process was very time consuming, requiring multiple hours of work from several people, starting from the initial analysis to the notification of revised SOL. To maximize the WOCN path SOL, the base case was modified to more accurately reflect actual system conditions while maintaining system reliability.

The following adjustments were made to the off–line system model:

- Increased reactive support in the Puget Sound Area;
- More accurate modeling of generation patterns in Upper and Mid Columbia;
- Reconfigured the State Estimator saved case to solve in the off–line PowerWorld program. These results needed to be validated against the WECC developed case; and

- Altered Northern Intertie flow to more closely resemble system conditions. This updated case resembled what was seen in the State Estimator off–line case, which allowed the State Estimator case results to be used, as they were the most conservative.

This type of analysis is used when actual flows are approaching the path SOL.

1.10 WECC Reliability Coordinator (RC)

BPA Dispatch maintained contact with the WECC RC throughout the events. The WECC RC expressed no concern and relayed information that no Load Serving Entity had pending or requested Emergency Energy Alerts.

2.0 Curtailments/Redispatch/Stop Sales

2.1 WOCN SOL

On May 14 the studies for the combined Olympia – Grand Coulee and Echo Lake – Monroe outages determined the WOCN SOL ranged from 5980 MW to 6425 MW.

On May 17, BPA posted notice on the BPA OASIS Outage page (#77375) of a minimum WOCN SOL of 5980 MW from May 18 at 0000 to May 23 at 1500, due to the combined Olympia – Grand Coulee and Echo Lake – Monroe outages.

On May 21, BPA posted notice on the BPA OASIS Outage page (#77617) of a minimum WOCN SOL of 7260 MW from May 21 at 1900 to May 23 at 1500, reflecting that the Olympia– Grand Coulee line returned to service and only the Echo Lake – Monroe outage continued.

2.2 Overview of the WOCN Congestion Events

On May 18, at 0654, an alarm signaled Dispatch that the path loadings were approaching the maximum WOCN SOL (the maximum WOCN SOL, 6425 MW, applied since ambient temperatures were under 68° F). Dispatch notified counterparts at Puget, Seattle, Snohomish, Tacoma, British Columbia Transmission Corporation (BCTC) and the WECC RC that the WOCN SOL is expected to be exceeded from 0700 – 2300, and posted a notice on OASIS (#77426). From 0712 to 0716, Dispatch requested PS to provide discretionary redispatch from the Upper Columbia River Projects to the Lower Projects, and Power Services agreed. At 0718, Dispatch also requested BCTC to move the Nelway phase shifter to increase flows on the Eastside Northern Intertie S-N. At 0733 Dispatch requested Transmission Scheduling to stop new non–firm sales on the

WOCN for HE8–HE22. Power flow started to exceed the WOCN SOL from 0750 through 0801 and 0807. From 0811 to 0815, Dispatch requested PS to provide Discretionary Redispatch from the Upper Columbia River Projects to the Lower Projects, and PS agreed. A curtailment was implemented at 0814. Dispatch lifted the request to stop sales at 0920. The SOL was exceeded again at 0941, and a curtailment was implemented at 0944. Dispatch re–executed a revised request to stop new non–firm sales at 0948 for HE11 – HE20. The last curtailment was implemented for SOL exceedences at 1014. At 1139, Dispatch executed a request to stop new firm and non–firm sales for HE10 – HE20. At 1205, the maximum WOCN SOL was revised to 6650. At 1552, Dispatch executed a request to stop sales for both new firm and non–firm sales from May 19 to May 21 for HE08–HE20.

On May 19 at 0632, an alarm signaled Dispatch that the path loadings were approaching the WOCN SOL. Dispatch notified counterparts at Puget, Seattle, Snohomish, Tacoma, BCTC and the WECC RC of the high probability of exceeding WOCN SOL through 1700, and at about 0644 posted a notice on OASIS (#77479). Dispatch also requested PS to provide Discretionary Redispatch from the Upper Columbia River Projects to the Lower Projects, and PS agreed to redispatch for HE08–13. Dispatch requested BCTC to move the Nelway phase shifter to increase flows on the Eastside Northern Intertie S–N. At 1513 and 1532, power flow exceeded the WOCN path SOL. At 1535, Dispatch bypassed the Columbia 500kV series caps on Grand Coulee–Shultz #1 & 2 500 kV lines to reduce WOCN flows. At 1604 flows exceeded WOCN SOL, and about 1615 a curtailment was implemented. At 1700 the new maximum WOCN SOL was revised to 6881MW.

Figure 1 shows a time history plot of WOCN East to West path loadings and SOL, referred to below as OTC.

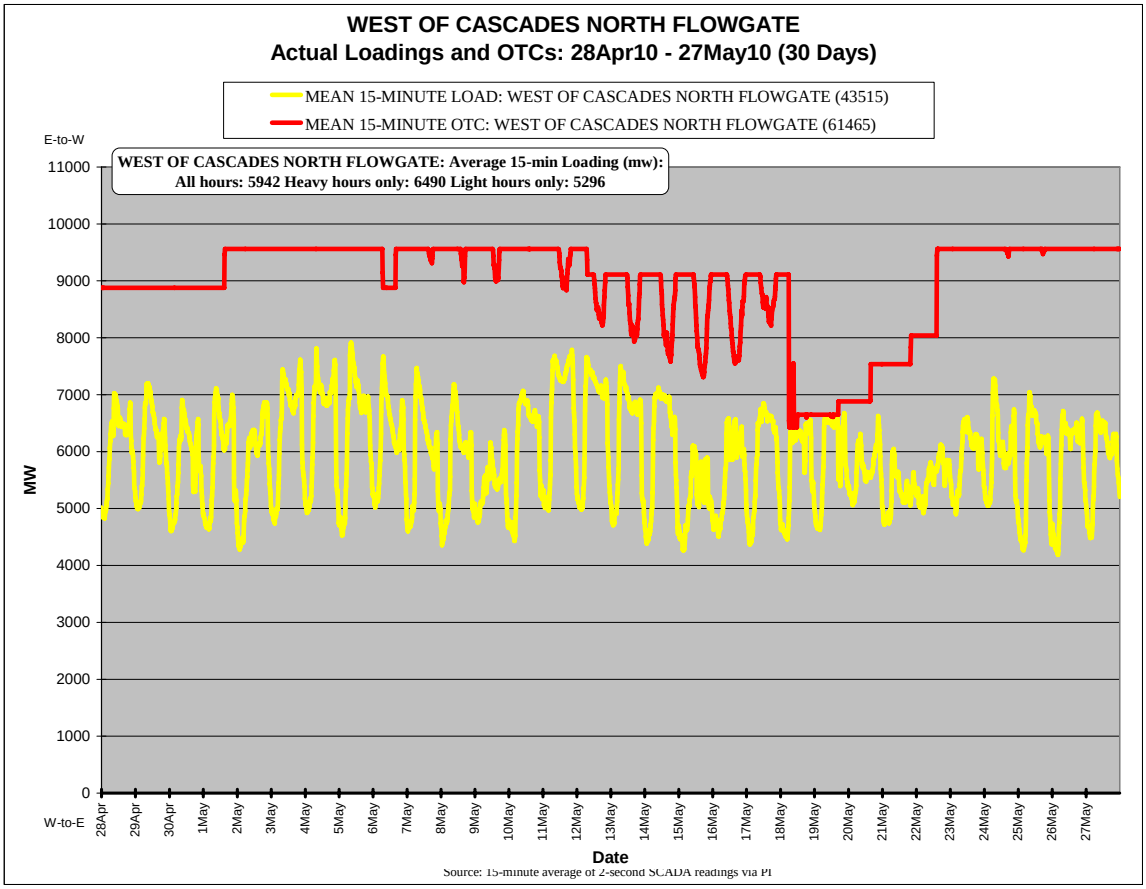


Figure 2 –Loading & OTC vs. Time

2.3 Transmission Congestion Curtailment

As path loading approaches path limits, Dispatch is notified with a warning alarm at 1000 MW and again at 500 MW below SOL. If the SOL is exceeded, Dispatch attempts to mitigate the excursions by first implementing relevant switching actions defined in the DSO applicable to the path and then requesting Discretionary Redispatch from PS. If those actions do not mitigate the SOL excursion, Dispatch implements curtailments to tagged schedules on the specified network flowgate using the network curtailment calculator, iCRS. If iCRS curtailments do not mitigate the SOL excursion, then Dispatch implements curtailments on the interties.

The iCRS tool is used for real time events in hour. The iCRS tool evaluates the impact of the scheduled Point of Receipt (POR) (Generation), Power Utilization Factor (PUF), and the Point of Delivery (POD) (Load) PUF of each network tag to determine its impact on the selected flowgate. A PUF is also known as a Power Transfer Distribution Factor, or PTDF. The iCRS tool applies BPA's Short Term ATC Methodology to determine the impacts of tags on the selected path(s). The Short Term ATC methodology specifies that the impact of transmission requests on the network that are less than 10 MW and have less than a 10% PUF value will be ignored and considered to have *de minimis* impact on the path. The iCRS tool therefore assesses each network tag to determine its non–*de*

minimis impact on the path. Because the impact of each network tag is based on PUF factors, it is possible that the full MW value of the tag will provide only a portion of the necessary relief on the selected path. The following is the formula used to determine the impact or potential relief a given tag provides on the selected path:

Impact to path = (POR PUF – POD PUF) * Transmission Demand

Under a contract path methodology, some schedules might provide a counterflow benefit to a congested path (e.g., BPA's Interties). BPA, however, uses a flow based methodology on the network. Therefore, any tag on the network may have an impact on the identified flowgate, but only tags with a non–*de minimis* impact on the selected flowgate are identified for curtailment. The tool calculates a pro rata reduction to each identified tag in NERC priority order. The iCRS tool applies curtailments to all of the tags in the priority block (e.g., 1–NS) on a pro rata basis to get the overall relief. If curtailment to the tags in that block are not sufficient to provide the necessary relief, then the iCRS also selects the tags in the next priority block (e.g., 2–NH) and implements curtailments, on a pro rata basis, and continues through each priority block up to the relief needed.

Curtailments, however, are not as precise as they might otherwise be. The Short–Term ATC methodology and the iCRS tool assume a single dispatch for the FCRPS. The iCRS tool is not updated for real time conditions, including updates of the FCRPS generation dispatch data. In addition, few schedules are tagged from specific resource (source) substations to specific load (sink) substations. Many interchange tags may be system–to–system, or resource to system, and tags within the Balancing Authority may be from the BPA System or a generating resource (wind farm) to a customer's system. An hourly ATC methodology with updated real time operating conditions and FCRPS dispatch patterns, and modifications to BPA's processes and procedures that require more granularity (e.g., redispatch protocols, zonal scheduling or other specificity) would likely allow BPA more visibility of the system limitations in real time. Under these conditions, the iCRS tool might curtail fewer MWs (and tags) to get the necessary relief on the path.

BPA plans its transmission system for long–term commitments, and has adopted a Long Term and Short Term ATC methodology for network sales. BPA, however, does not presently have an hourly ATC methodology on the network, which results in selling unlimited hourly firm and non–firm transmission on the network flowgates. Customers use the unlimited access on the network flowgates for their real–time energy market arrangements. BPA, however, is developing an hourly ATC methodology to comply with the NERC Reliability Standards that will allow BPA to limit transmission sales for both hourly firm and non–firm requests. Until an hourly ATC methodology is in place, if congestion occurs on a flowgate and the path SOL is exceeded or expected to be exceeded, BPA will use its current mitigation tools, including curtailments and the Stop Sales tool, to limit flows as appropriate.

On May 18, BPA implemented iCRS congestion curtailments to tags that had a non–*de minimis* impact on the WOCN path, East to West, for each of HE09, HE10, and HE11.

During this period the Path SOL was 6425 MW, and power flows exceeded the SOL prior to the curtailment. On May 19, BPA implemented iCRS on the WOCN path, East to West, for congestion in only HE 17. The Path SOL during the curtailment was 6650 MW and the power flows exceeded the SOL prior to the curtailment.

A summary of the curtailments follows:

Date	HE XX	Relief Requested by Dispatch	MW Curtailed	1–NS	2–NH	6–NN	7–F
5/18/2010	9	300	770	770	0	0	0
5/18/2010	10	300	717	499	1	103	114
5/18/2010	11	300	777	527	1	94	155
5/19/2010	17	200	354	181	173	0	0

The iCRS tool only implements curtailments, and only curtails tagged scheduled transactions. Presently, iCRS cannot implement redispatch for any NT transactions that have a non–*de minimis* impact on the path. Therefore, tagged firm NT schedules that had a non–*de minimis* impact on the path, including some tags from the FCRPS to BPA NT customers, were also curtailed when tags in the firm priority block (7–F) were curtailed. BPA needs to establish a mechanism to quantify the non–*de minimis* impact exposure NT transactions have on a flowgate, and develop procedures for redispatching NT resources (both Federal and non–Federal resources).

In addition, iCRS does not currently account for any untagged transmission uses from the FCRPS. Therefore, BPA needs to develop a mechanism that accounts for all untagged uses of the FCRPS, including identifying uses attributed to: 1) untagged deliveries from the FCRPS to BPA's NT customers; and 2) BPA's Automatic Generation Control (AGC) system (e.g., for reserves, regulation, imbalance energy, etc.), losses, and other similar uses. The untagged deliveries from the FCRPS to BPA's NT customers should be included in the quantification of non–*de minimis* impact exposures NT transactions have on a flowgate, and in procedures to redispatch Federal and non–Federal NT resources.

BPA should also determine the appropriate method to account for FCRPS–supplied AGC, losses and other untagged uses of the FCRPS in the NERC ATC Methodology.

2.4 Discretionary Redispatch

BPA does not currently redispatch NT service, but there were several requests from Dispatch to PS for Discretionary Redispatch over this period. PS accommodated the requests by increasing generation at the Lower Columbia projects and decreasing generation at Grand Coulee and Chief Joseph. However, due to the minimum flow requirements into Priest Rapids (PRD) for the fish migration, PS was limited on how much generation could be reduced at GCL and CHJ and was not able to accommodate all requests for redispatch.

On May 18 at 0712, Dispatch requested PS to redispatch 200 MW from Grand Coulee and Chief Joseph to the Lower Columbia projects before it began to implement curtailments; and at 0811 Dispatch requested PS to redispatch 200 MW from the Upper Columbia projects to the Lower Columbia Projects. On May 19, at Dispatch's request, PS redispatched 210 MW from the Upper Columbia to Lower Columbia for HE09–HE13; and limited redispatch to only 130 MW from the Upper Columbia to Lower Columbia for HE14 to accommodate fish migration.

On May 18, Dispatch posted a notice declaring a Transmission System Emergency. The DSO for mitigation for exceeding the WOCN SOL, included a Transmission System Emergency declaration. This declaration informed PS and the WECC RC that BPA may have to move outside of the dispatch patterns for the applicable Biological Opinion objectives to maintain reliability. The Transmission System Emergency was declared for the one hour only and was done consistent with DSO 141.

BPA may modify NT redispatch procedures and protocols and the iCRS tool to: 1) quantify the non–*de minimis* impact exposure NT transactions (both Federal and non–Federal resources) have on a flowgate; 2) account for untagged deliveries of the FCRPS to NT customers; and 3) implement redispatch to Designated Network Resources. If successful, BPA may also need to review and modify internal procedures for Discretionary Redispatch.

Date	HEXX	MW Request	MW Provided
5/18/2010	8	200	200
	9	200	200
5/19/2010	8	210	210
	9	210	210
	10	210	210
	11	210	210
	12	210	210
	13	210	210
	14	210	130

2.5 Stop Sales Tool

BPA has in place ATC methodologies for the network Flowgates that are applicable to only long–term and short–term periods. Currently, BPA does not have an hourly ATC methodology for its Network Flowgates. An hourly ATC methodology would allow BPA to better manage the impact of new hourly reservations, including new redirect and intra–hourly requests, and hourly schedules for existing and new reservations that may cause the path SOL to be exceeded.

Therefore, to manage congestion during periods that the path SOL is expected to be exceeded, BPA may implement the Stop Sales Tool, also known as the OATI Network Congestion Validation or TLR Avoidance tool (Tool). The Tool allows BPA to stop new

sales (short–term and/or hourly), when directed by Dispatch. This Tool prevents the automated short term reservation system from accepting any new firm (if selected) or non–firm (if selected) reservations, including redirect and intra–hour requests, that have a greater than *de minimis* impact on the selected path during the selected start/stop period. The Tool does not restrict customers from scheduling on existing reservations. Under the Tool, AFC/ATC is forced to zero on the selected path during the selected start/stop for new firm (if selected) or non–firm (if selected) reservations. The firm/non–firm selection, path selection, and start/stop time period selection are entered for each stop sales event by the Transmission Scheduler based on directions provided by the Dispatcher.

On May 18, BPA Dispatch executed Stop Sales for non–firm reservations at 0733 for HE8–HE22. Dispatch lifted Stop Sales at 0920 and re–executed it at 0948 for non–firm reservations for HE11–HE20. Dispatch executed Stop Sales for firm reservations at 1139 for HE10–HE20. At 1552, Dispatch executed Stop Sales for any firm/non–firm reservations May 19 to May 21 for HE8–HE20. However, the pre–scheduling period for May 19 was already completed at 1552, so Transmission Scheduling applied the limits to those hours on May 19 in real time and for the pre–schedule period for May 20–May 21 for HE8–HE20. Transmission Scheduling arranged to post a notice on the OASIS home page at 1612, and sent an email exploder to customers informing them that of the Stop Sales action on May 18 through May 21.

During May 19 and 20, Dispatch explored whether limited amounts of capacity on the WOCN path could be released to the market. The Tool, however, is an "on" or "off" tool for the specified hours and days, and does not permit BPA to release a set amount of capacity. Unless the Tool is "on" for either or both firm and non–firm reservations in the specified hours and days, new firm and non–firm reservations for those periods (short term or hourly) would be allowed. The net result was not to release any capacity on the WOCN path for new reservations. If the tool had been turned "off," all new hourly reservations, including new redirect and intra–hourly requests, with non–*de minimis* impacts would have been allowed. Without these limits, unlimited hourly sales, likely would have continued to contribute to path SOL exceedances, and required additional curtailments on the path. On May 20, at 1610, Dispatch lifted Stop Sales.

During the period that Stop Sales was effective, the number of Transmission Service Requests (TSR) refused and confirmed by BPA were as follows:

TSR Queue Time	Refused	Confirmed
05/18/2010	166	~270
05/19/2010	355	~503
05/20/2010	242	~465

The confirmed TSRs were determined to have less than a *de minimis* impact on the path.

In addition, the Tool is designed by OATi. It therefore, does not include all of the features of tools designed by BPA. For example, BPA's Short–Term ATC methodology allows the impact of the original reservation to be netted against the impact of a new

Redirect reservation. In contrast the Tool was designed to meet the Order 890 requirements, and does not allow the impact of the original reservation to be netted against the impact of a new Redirect reservation. Therefore, the Tool may refuse or disallow new requests for Redirect reservations that have a non–*de minimis* impact on the specified path.

As explained above, BPA does not presently have an hourly ATC methodology on the network. Consequently, there is unlimited hourly firm and non–firm transmission use on the network flowgates. BPA plans the network transmission system for long–term commitments and schedules maintenance outages to maximize the transmission flowgate transfer capability for those long–term commitments. Customers, however, use the unlimited access on the network flowgates for their short–term and real–time energy market arrangements. If congestion occurs on a flowgate and the path SOL is exceeded or expected to be exceeded, BPA will need to use its current mitigation tools, including curtailments and the Tool, to limit flows as appropriate until adoption of an hourly ATC methodology consistent with the NERC Reliability Standards.

2.6 Communicating WOCN Path Curtailment to Customers

Listed below is a summary of the messages or notices posted on OASIS regarding the May 18–19 Stop Sales and curtailments.

- On Monday, May 17 at 0652, notice #77375 was posted on the OASIS outage page with the updated WOCN SOL of 5980 MW to start on May 18 at 0000.

- On May 18 at 0635, BPA posted a message in OASIS # 77426) regarding a scheduling/curtailment outage. It read "Scheduled outage of Echo Lake – Monroe – Snoking #1 500 KV line. West of Cascades North SOL expected to be exceeded daily from 0700 – 2300. Mitigation will be used per established procedure. Valid from 5/18/10 at 0635 to 5/23/10 at 1500."

- On May 18 at 0812, BPA posted a message in OASIS (# 77443) declaring a Transmission System Emergency on WOCN. It read "BPA is declaring a transmission system emergency due to West of Cascades North (path 4). Valid from 5/18/10 at 0812 to 5/18/10 at 1200."

- On May 18 at 1612, BPA posted a notice on the OASIS home page and sent an email exploder to customers notifying them that BPA implemented the Stop Sales on May 18 through May 21 for specified hours.

- On May 20 at 1937, BPA posted a short explanation lifting Stop Sales on the Transmission external web site under "News".

May 21 at 0820, BPA posted a short explanation lifting Stop Sales on the front page of OASIS. It read "Curtailments were implemented on May 18 in multiple hours and for one hour on May 19 to reduce power flows below the SOL level in those hours. In

addition, BPA redispatched the FCRPS. Because BPA expected power flows would continue exceeding the path SOL levels, BPA implemented measures to limit new hourly sales affecting the path. Due to new studied conditions, BPA is able to increase the path SOL and lift the sales limit, effective immediately. Please contact your Transmission AE for more information."

3.0 DSO216 Curtailments

As a result of the loading concerns on the WOCN path, and the limits on resources available for reserves, the wind generator reserve band was restricted. On May 19, BPA posted a notice (#77560) informing customers that BPA limited total INC reserves to 668 MW. The notice explained that due to their location, the generators responding when INC reserves were deployed increased the WOCN path loadings. The Wind INC reserves limit was 41l MW.

On May 19, BPA notified Customers (#77544) that greater than 90% of INC reserves were deployed, and transmission schedules for wind generators were curtailed. Curtailments were implemented on May 19 at 1522 for HE16; and at 1607 for HE17; and on May 20 at 0662 for HE7. The following is a summary of DSO 216 curtailments.

Date	HE XX	MW Curtailed	1–NS	2–NH	6–NN	7–F
5/19/2010	16	365	13	21	82	249
	17	336	19	49	76	192
5/20/2010	07	345	151	76	3	115

4.0 Power Services and Customer Impacts

BPA plans its transmission system for long–term commitments, and performs regular maintenance on its network flowgates to maximize transmission capability for those long–term commitments. BPA adopted a long term and short term ATC methodology for network sales. BPA, however, does not presently have an hourly ATC methodology on the network, which results in unlimited hourly firm and non–firm transmission use on the network flowgates. Customers assume there is low risk that access on the network flowgates for their short–term and real–time energy market arrangements will be interrupted, curtailed or denied. BPA, however, is developing an hourly ATC methodology to comply with the NERC Reliability Standards that will likely limit transmission sales for both hourly firm and non–firm requests. Until an hourly ATC methodology is in place, if congestion occurs on a flowgate and the path SOL is exceeded

or expected to be exceeded, BPA will use its current mitigation tools, including curtailments and Stop Sales, to limit flows as appropriate.

The primary complaint from customers was that they were unable to access hourly transmission service to deliver their short-term market arrangements. Many customers, including PS, explained that because they could not obtain new hourly transmission service, including new requests for Redirect service, prices at the MID–C market plummeted.

4.1 Impacts to PS

PS estimated the curtailments from May 18–20 cost BPA approximately $1M in lost revenue.

- Redispatch of the Upper Columbia Projects (Grand Coulee and Chief Joseph) to Lower Columbia Projects reduced flexibility of the hydro system.

- The majority of the cost to PS was the "lost revenue" that resulted when MID-C market prices fell from $30 to $20 during the week. Hourly prices were at $10. MID-C is the average price for the month of the Dow Jones daily firm on–peak index price.

- The $1M estimate is based on the assumption that PS has 100% LD financial protection against the approximately 6000 MWh of tags cut across the event.

- No spill occurred.

- The Columbia Generating Station (CGS) reduced its output by 3500 MWh starting HE09 on May 20 through HE10 on May 21.

4.2 Endangered Species Act Impacts

Redispatch of the Upper Columbia Projects (Grand Coulee and Chief Joseph) to Lower Columbia Projects reduced flexibility of the hydro system. However, PS was limited on how much generation could be reduced at Grand Coulee and Chief Joseph due to the flow requirements into Priest Rapids for fish migration. PS was required to take the following steps to avoid interrupting flow objectives for fish:

- The schedule for spill at John Day was re–arranged. Instead of switching to 30% spill level at 0600, BPA requested to stay at 40%.

- The schedule for spill at Ice Harbor was re–arranged to stay at 45 kcfs.

The adjustments were made to reduce generation while still meeting flow objectives during the curtailment period. PS was able to make the adjustments (reduced CGS output

and adjustments to spills) to move the volume of water required to meet the Biological Opinion objectives.

4.3 Impacts to other Customers

MID–C owners also had limited flexibility operating the MID–C hydro projects. They were conducting fish studies required as part of their FERC license, and their hydro operators were concerned that they were at risk for passing water in violation of those studies. No violation occurred. Powerex was also concerned that a prolonged constraint might force spill from lower reservoirs in the British Columbia hydro system. Douglas had a similar concern.

Several customers (e.g., Powerex, PGE, Snohomish) expressed concern that curtailments were not implemented consistent with NERC priorities, and also question why new requests in other areas of the network were affected by the WOCN limits. One customer's (PSE) complaint was directed at how curtailments are implemented on dynamic transfers. Customers also expressed frustration with the apparent inconsistency of treatment between BPA's congestion management tools (e.g., the Stop Sales Tool does not recognize netting for redirect requests that are accommodated under BPA's Short Term Firm ATC methodology).

Many customers (e.g., TransAlta, Calpine, PSE, PGE) were not able to use low-cost power purchases, and instead had to operate higher cost thermal projects that otherwise were idled or were out or planned for maintenance. Although there were multiple complaints regarding the ability to serve load, the basis for the complaints appeared to be economic or financial impacts. There were no customer initiated Energy Emergency declarations and no load service was interrupted.

Many customers (e.g., Power Services, TransAlta, Calpine, Powerex, PGE, PSE, Snohomish, Douglas, Avista, Tacoma, SCL) depend on new hourly sales and hourly redirect service to enable them to deliver their daily market commitments. Customers rely on this service to reduce risks (e.g., financial penalties) under their power sales arrangements, if the power cannot be delivered. These customers were directly limited in their ability to deliver power that depended on these transmission arrangements due to interruptions caused by curtailments and restrictions on new hourly sales. This included daily power purchases and sales to serve load and for export sales. Some customers (e.g., Powerex) question whether it was appropriate for BPA to limit new hourly firm requests, in particular, new firm redirect requests. Customers claim that the inability of customers to access hourly transmission, including Redirect service, resulted in prices at the MID-C market to plummet. At one point MID–C prices were at $1.

In some cases (e.g., Tacoma, SCL, Powerex), the combination of curtailments and limits on new sales forced customers to call on power sourced from their hydro facilities, and affected economic operations or management of their river systems.

Several customers (e.g. TransAlta, Tacoma, Snohomish, SCL, Calpine, IPC, PGE) also expressed concern that outages are not well coordinated, information is not sufficient, and that access to updated BPA outage information is challenging and the consistency of the information is lacking. Customers (e.g., TransAlta) expect BPA to produce reliable outage forecasts that are accurately and uniformly updated through real time. Almost all of the customers were frustrated at the lack of information on the WOCN congestion and how long BPA expected the conditions to last. TransAlta is concerned that BPA does not appear to consider the combined impacts of outages. TransAlta is also concerned that many market participants do not easily understand the monthly outage plans that are published by BPA as part of the NWPP 45–day Outage Coordination Process.

Because BPA was not able to provide transmission service, many customers turned to adjacent providers (e.g., PacifiCorp) for service and received it.

4.4 Recommendations from PS and Customers

When performing studies, work with PS and Load Forecasting and Analysis to get the most accurate and up–to–date generation pattern and load information.

Provide timely communication from TS to PS Generation Supply once limitations are determined.

Provide better visibility across BPA operations (transmission and generation) in order to enable a more coordinated response.

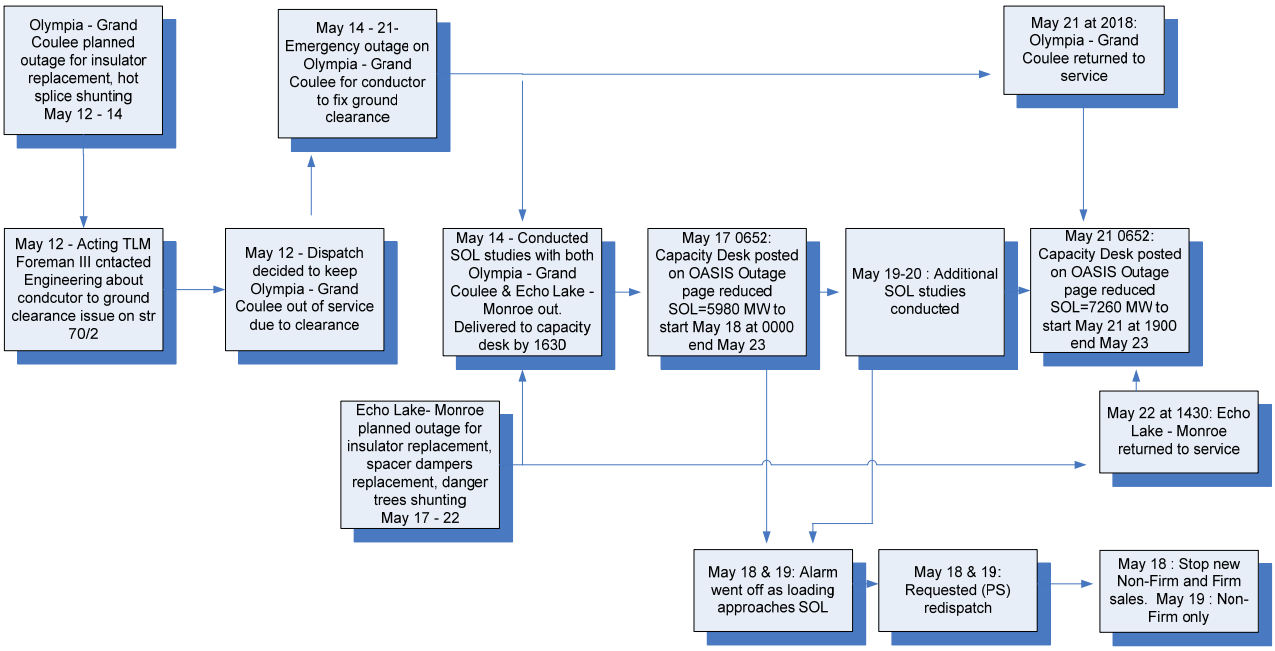
A group of Customers (Tacoma, Snohomish, Seattle, Calpine, Idaho, PGE) recommend, that for transparency, customers should be involved in the analysis, and development of solutions of the Lessons Learned investigation. Specifically, recommend that “the analysis should include, but not be restricted to, a direct comparison of actual line loadings and stability limits with the model results that were relied upon to limit transmission reservations and scheduling during the event.”

These customers recommend that BPA address how information regarding outages is delivered. They also recommend that BPA adequately publish important information. Puget recommends that BPA correct and improve its procedures and processes to deliver transparent outage notices. TransAlta suggests improvements to the NWPP 45–Day Outage Coordination Process, and recommends BPA address inconsistencies of outage information across multiple web pages, and that BPA provide timely and accurate updates of outage information. Specifically, TransAlta suggests that BPA get detailed and useful information to the market “as events are happening,” and broadcast information in a uniform fashion such as an email exploder.

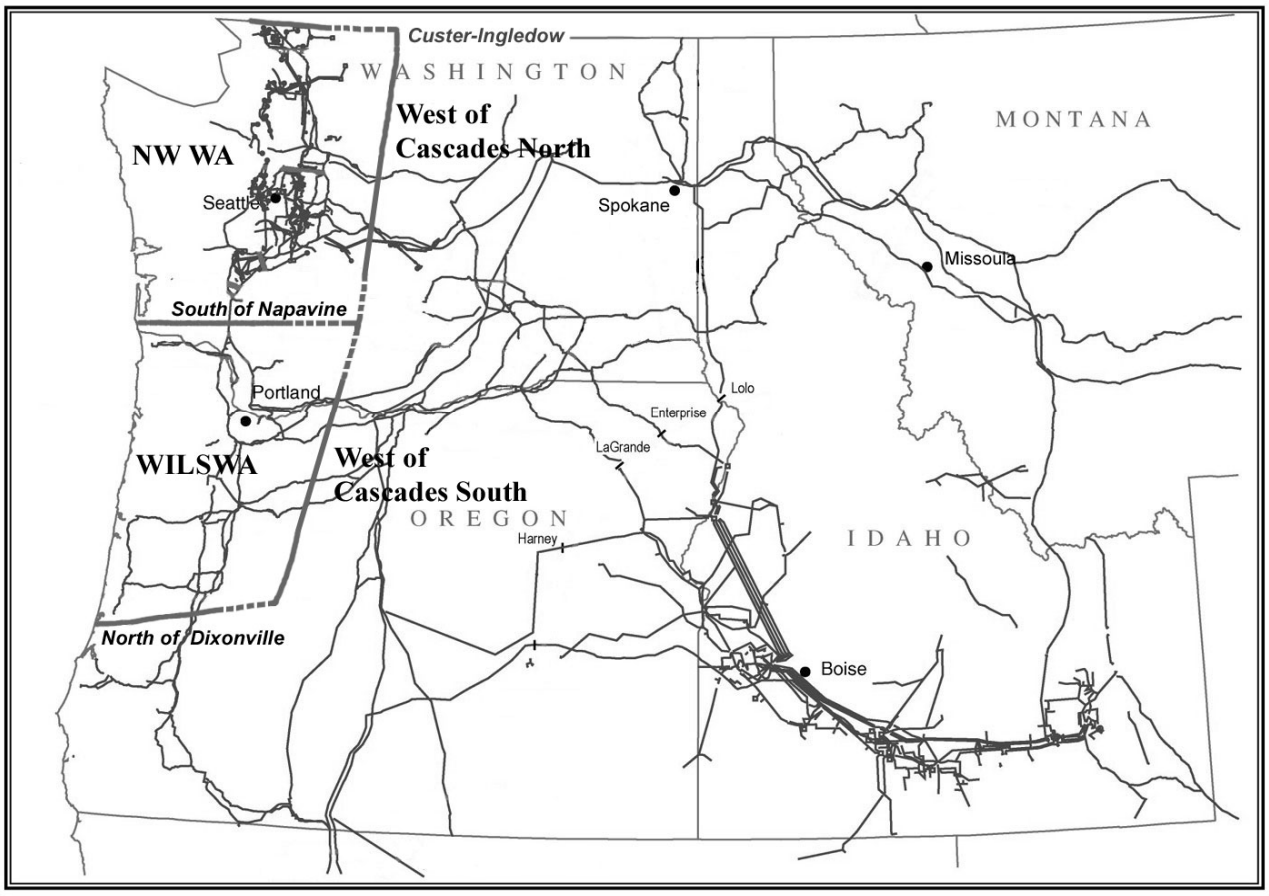
These customers also recommend that BPA investigate alternative or tiered approaches to implementing “high impact tools” and consider their impact on the economic markets.

Several customers request clarification of the iCRS tool. Puget requests that BPA clarify its redispatch and curtailment practices for all transmission services, and bring its curtailment practices into conformity with the OATT and other expected practices.

Events Schedule



NW WA & WILSWA AREAS



Revision History

Date	Version	Description	Approved by
10/4/2010	**1.0**	**Final**	