

Regional Transmission Adequacy Technical Workgroup

Apr. 27, 2005

Draft Meeting Notes

Action Item

1. Modify the process clarification document – Ravi Aggarwal
2. Send So Oregon results electronically – Don Johnson
3. Modify PacifiCorp document with additional points showing the dynamic behavior of the market – Don Johnson
4. Identify ways to separate transfers related issues with load service issues. Example, So Oregon, Puget Sound, Spokane Area, Portland Area – Chris Reese
5. What were the reasons for limiting firm COI/PDCI and NI sales? – Ravi Aggarwal
6. Identify other ongoing or completed efforts in developing transmission adequacy guidelines – Ravi Aggarwal
7. Revise studies presented during the Apr. 27 meeting. Revise studies to reflect suggestion how to consider adequacy of the load service region.
 - a. So Oregon: COI Imports Vs So Oregon load service – Don Johnson
 - b. Olympic Peninsula (N-2) – Marv Landauer
 - c. So Oregon Coast (N-2) – Marv Landauer
 - d. Puget Sound System (N-1-1) – Gordon Dobson/Chris Reese
 - e. Redmond and Eugene Area (N-1-1) – Ravi Aggarwal (on behalf of BPA Technical Operations)
8. Benefit/Cost Tools and other suggestive approaches to measure system performance and identify system requirements – Bill Mittelstadt and All

Suggested Topics for Next Meeting

- Finish presentations from previous meeting (Bill Mittelstadt and Ravi Aggarwal)
- Review action items (inclusive of updated presentation)
- Discussions related to suggestive guideline proposal

Meeting Notes:

1. Introduction (well attended meeting with about 17 attendees)
2. Purpose clarification (TAG): A draft version providing further clarification to the efforts was discussed. The purpose of this discussion was to discuss and get input from the technical workgroup (TW). The document was prepared as a result of discussions on Apr. 12 Transmission Adequacy Steering Committee (TASC) meeting.
3. Some of the early discussions included:
 - Economic adequacy – No constraints, market enabling (fixes: congestion mitigation). However, the question is enabling market at what cost?

- Alberta transmission system – builds ahead of the market need (planning for economics) – Rate Structure enables cost recovery.
- Analyzing economics of transmission:
 - Policy to enable market at any cost?
 - Factor economic transactions in evaluation process
 - Evaluate outage cost to the customer (Physical and Economics)
 - Cost/Benefit analysis
- Minimizing total cost to the customer is the goal. In an ideal situation, increase in transmission rates should signal reduction in power rates (Vertically integrated model). Under the new paradigm, this is hard to achieve.
- Transmission Adequacy Guidelines (TAG) process helps ties back together the separation.
- Clarification was requested between the public/private – Different goals → Public transmission company work to minimize cost to the ratepayers whereas the Private works for profit. What is the level of acceptable risk whether public or a private entity?
- Regional diversity makes it difficult to get to a unified set of guidelines but efforts should be made to address regional diversity and different needs.
- Region meets load for N-1 and N-2 and if the region does not then default to definition of local area network as defined by WECC.
- Require balancing between generation and transmission costs. Economic aspects should be factored when making decision.
- Reference: PacifiCorp Presentation (TAG2.PPT): Identify where are we now? Design the system to meet point 3.
- Point 3 is only a single point and not fixed in time. Point will change with changing market conditions and guidelines should be dynamic to adjust to these changes.
- Need to plan a system that is manageable in real time by the system operator. Need to know what the system operator can handle
- Should we plan for uncertainty and build on speculation?
- Flexibility for change in demand: Demand response – Shed load economically (interruptible load)
- What is considered as acceptable level of performance and who decides this?
- Factor cost of met load and outage in decision process.
- System capacity lost post 1996 August disturbance. Full system capacity has not been restored since the cost is too high (both politically and from societal perspective).
- Who bears the system cost?
- Ranking of projects should be based on outage risk and cost of risk
- Transfers Vs load area: Stake with transfers is too high. Cut transfers based on Non Firm and Firm usages – Adequacy Guidelines should be based on firm usage.
- Re-dispatch should be considered → Economics: Cost differential. This is a multiparty issue and need to find ways to assess costs.

- Guidelines should suggest when the cost becomes large enough to build infrastructure.
- Suggestion: Using production cost tool with and without project → Conceptually simple but data (input) is difficult → Highly dependent on situation and driver
- Actual cost of loading change: Cost of dropping load Vs re-dispatch cost
- Path utilization: Number of times transmission request was rejected → Resulting in curtailments (Suggest talk with Dean Perry)
- Following an N-1 outage, adjustment should not exceed for what is required for 1 in 2.
- % Benefit gained for the path is small for number of curtailment.
- Additional material presented by Bill Mittelstadt (Transmission Guideline.PPT)
- SAIDI/SAIFI: Exposes/disadvantages low density load
- Price Volatility → Economics is an issue but have to factor volatility.
- Outages are more common on distribution system → Value of transmission improvement depends on geographic scope → to optimize system cannot apply guidelines to a system as a whole rather may be more local.

4. Benchmarking of current situation

- i. Snohomish – see TD Planning 1-18-05(cut).PPT presentation
 - Target: Load density
 - Optimal: SAIDI of 120 minutes
 - Define duration (time) and amount (MW)
 - Transmission outage duration: Per event and not during a year(s)
 - Forecast techniques to identify actual SAIDI impacts on future loads/exposure
 - Meet reliability criteria → May not be able to meet firm transfers but this is not a reliability but a commercial service
 - Adequacy assessment is limited to the bounds of the Load Service Entity and BPA beyond transmission system is not considered.
- ii. Southern Oregon (N-2)
 - So Oregon load: 1400 MW (Winter Peak) and 1100 MW (Summer Peak)
 - Meet N-1 criteria to serve load
 - Safety Net: Added Under-voltage load shedding for outages beyond N-1 and N-2 and load conditions beyond 1 in 5 winter load
 - COI S-N transfers related with the So Oregon loads. Some utilities are banking on S-N capacity to meet load service requirements.
 - Further studies are required to study relationship between transfers and load service – Study import nomogram limitation
- iii. Olympic Peninsula and Southern Oregon Coast (N-2)
 - Olympic-Shelton 1 and 2 (Mean Time Between Failure = 7.5 years)
 - Local load service issue

- 1200 MW load versus 100 MW load
- Plan around peak to limit exposure
- N-1 for load service
- So Oregon coast would not be solved even if utility industry were vertically integrated. Distributed generation can solve problem but are there resources to build generation.
- What are the customer expectations?
- What are the risks and at what costs? What are the probability and the hours of exposure?
- What is the societal cost for loss of load? Can part of the load be restored? To identify societal cost: Separate residential, customer, and industrial load.
- Using specific examples → Distill to drive some principles, which would help in developing guidelines [MTBF, Outage duration...]
- What is the cost of improving the system: Load tripping Vs. Fixing the System (Factor societal cost)

iv. Puget Sound (N-1-1)

- In 6 weeks 3 instances where Canadian Entitlement Return (CER) was curtailed. Twice in real time and once in pre-schedule.
- CER is like firm load at US Canadian Border and PBL is to deliver upon when called upon. The instance mentioned in the first bullet suggests curtailment in load. Is load curtailment in such situation acceptable when the service is considered firm?
- Echolake – Maple Valley outage is more sensitive to load than transfers.
- The situation described is of a N-1-1 (Monroe-Echolake o/s and loss of Monroe-Sammamish 230 kV line).
- How does the region increase the robustness for N-1-1?
- Conditions exist where a swing of 3000 MW is required on the Northern Intertie to bring system within criteria → Not a robust system
- Seattle load is approximately 7500 MW and CER is approximately 1400 MW → Curtailment of CER is approximately 20% of the load and that is a big hit.
- When should/shouldn't transmission be built for parallel path related issue?
- Sensitivity to transfers: Change in transfers as a relation to amount of load reduced.
- Allocate path between firm and non-firm

v. Redmond/Eugene (N-1-1)

- Transfer Vs. Load Service (Operational Issues)
- Discussions to be carried out in the next meeting

Regional Transmission Adequacy Guidelines
Technical Workgroup Meeting
Apr. 27, 2005
PDX Conference Center

AGENDA

1. Introduction and changes to the agenda
2. Purpose Clarification (Transmission Adequacy Guidelines)
3. Transmission Adequacy Issues - PacifiCorp
4. Benchmarking
 - a. So. Oregon – PacifiCorp
 - b. Load Service Areas – BPA
 - c. Puget Area – Powerex
 - d. N-1-1 (Redmond and Eugene Area) – Ravi
 - e. Others
5. Next Steps/Assignments



Transmission Adequacy Work Group
April 27, 2005 – Portland, OR

Attendee List

	<i>Name</i>	<i>Company</i>	<i>Phone Number</i>	<i>Email</i>
1	Michelle Poyourow	PPC	503. 232-2427	michellep@ppcpdx.org
2	Hugh Nguyen	PSE Merchant	425. 462-3001	hugh.nguyen@pse.com
3	Gordon Dobson-Mack	Powerex	604. 891-6004	gordon.dobson-mack@powerex.com
4	Roger Hamilton	West Wind Wires	541. 686-4839	hamilton.roger@comcast.net
5	Bill Mittelstadt	BPA-retired	360. 619-6672	wmittelstadt@bpa.gov
6	John Phillips	Puget Sound Energy	425. 462-3579	john.phillips@pse.com
7	Steve Andersen	EES Consulting/WPAG	503. 223-5900	andersen@eesconsulting.com
8	Linda Finley	Snohomish PUD	425. 783-1990	lafinley@snopud.com
9	Kenneth Dillon	Portland General Electric	503. 464-7400	kenny.dillon@pgn.com
10	Chris Reese	Puget Sound Energy	425. 462.3055	chris.reese@pse.com
11	Don Johnson	PAC	503. 251-5283	don.johnson@pacificorp.com
12	Nicolas Garcia	WUTC	360. 570-1084	ngarcia@wutc.wa.gov
13	Ravi Aggarwal	BPAT	360. 619-6681	rkaggarwal@bpa.gov
14	Dana Reedy	NWPP	503. 464-2806	dana@nwpp.org
15	Cliff Perigo	TC	503. 636-6500	ccp7@comcast.net
16	Marv Landauer	BPA	503. 230-4105	mjlandauer@bpa.gov
17				
18	<i>PHONE:</i>			
19	Julie Reichle	NWE		
20	John Martinsen	Snohomish County PUD	425.783-4327	jdmartinsen@snopud.com