NORTHERN TIER TRANSMISSION GROUP

NTTG Order 1000 Public Stakeholder Meeting

Webinar/Conference Call

September 18, 2012

NTTG Order 1000 Project Reevaluation

NTTG Stakeholder Meeting

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Project Reevaluation

(Practices Sec 3.9)

- Reevaluation originally planned for all non-committed projects, each planning cycle
- Guidance in Order 1000/1000-A ties reevaluation of projects selected for cost allocation to failure to meet project milestones
- Concerns:
  - A project selected in one cycle could incur significant costs and potentially be replaced in subsequent cycle, even if meeting milestones
  - Perpetual reevaluation provides no certainty to project sponsors
  - Small changes in regional need could trigger project replacement/deferral
- Compromise reached, applied to all projects selected in the plan, for cost allocation or not

Conditions for Reevaluation

(Practices Sec 3.9)

- "Committed" projects
  - Selected in the previous plan, all permits and rights of way required for construction secured
  - Not subject to reevaluation unless project fails to meet development milestones such that region's needs will not be met
- Uncommitted projects – subject to reevaluation if:
  a. the developer fails to meet its project development schedule such that the needs of the region will not be met,
  b. the developer fails to meet its project development schedule due to delays of governmental permitting agencies such that the needs of the region will not be met, or
  c. the needs of the region change such that a project with an alternative location and/or configuration could meet the needs of the region more efficiently and/or cost effectively

Conditions for Reevaluation
(continued)

- In the event of (a) or (b), Planning Committee may remove project from the Initial Plan
- With regard to (b), if no alternative project is identified to timely meet regional needs, Planning Committee may reinstate with its new in-service date
- In the event of (c), an alternative project shall be deemed more efficient/cost effective if the total of its cost, plus incurred costs for the project being replaced/deferred, is at most .85 of the replaced/deferred project’s cost
- Footnote on NTTG’s intention re: cost recovery.

Selection for Cost Allocation in Successive Plans

(Practices Sec 3.10)

- To remain eligible for cost allocation, a project and a project sponsor must continue to meet all data reporting and submission criteria (Q8, Q1)
- Sponsor may request an updated allocation assessment in Q1 of subsequent cycles
- Cost Allocation Committee may initiate an updated cost allocation assessment if it believes conditions affecting cost allocation of a project have significantly changed
- If sponsor no longer meets the qualification criteria, the project may remain the plan but will not be eligible for cost allocation

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NTTG Order 1000 Metrics

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Production Cost Model Metrics

- Organize PCM meeting to discuss
  - Data and modeling sources, strengths and weaknesses
  - Concern current base case model and data is not capable of allocating benefits to the beneficiaries. Which changes are necessary for cost allocation purposes:
    - How to appropriately model system operation in the 10 year planning horizon?
      - Full EIM vs Simulated Bilateral future?
      - How is the region dispatched (BA dispatch vs regional dispatch vs WECC wide)?
    - BA granularity is required, is LSE granularity needed?
    - Power production and transmission rights assigned to TP/BAs?
    - Is confidential data necessary? Principally generation/fuel data
    - Etc
- Task Force has significant overlap with near term task force, once the near term metrics have been resolved, a meeting will be organized to discuss these issues and resolve how potentially modify the model and data so that the PCM could be used in the NTTG Cost Allocation process. Until these issues can be resolved, NTTG will use other Metrics for Cost Allocation purposes.

NTTG Order 1000 Metrics Non-PCM Metrics for 2012 Filing

- Lower Capital
- Losses
  - ~~Peak~~ combined with
  - Energy
- ~~Lower fuel / generating dispatch~~
- Contingency Reserve

NTTG Order 1000 Metrics Non-PCM Metrics for 2012 Filing

Lower Capital Cost – Project Deferral or Replacement Metric

- Estimate financial and economic impact through power flow modeling
- Defer or replace a project in the <u>initial</u> Regional Transmission Plan by
  - the addition of a project ("new project"),
  - a project identified in the regional study process, or
  - a new project included in a transmission provider's local transmission plan that is "rolled up"
- Capital costs associated with the "new project" will be allocated among
  - the new project sponsor and any of that project's beneficiaries
  - the project sponsor of the deferred/replaced project and any of that project's beneficiaries

NTTG Order 1000 Metrics
Non-PCM Metrics for 2012 Filing

- Energy Loss
  - Method of determining benefit
    - Utilize power flow software to compare losses before and after a project is added to the system.
    - The reduction in losses after a project is added represents the benefit.
    - Compute annual energy loss using multiple cases, calculation will be dependent upon the case selection
    - There are winners and losers in the loss analysis, allocate the net NTTG benefit to TPs
    - Energy loss valuation based on average energy price for the study year

NTTG Order 1000 Metrics Non-PCM Metrics for 2012 Filing

- **MSTI example:**

Case	Total WECC Δ Loss (MW)	Total NTTG Δ Loss (MW)
NT_11_OCT4H21	-47.75	-14.74
NT_11_DEC22H18	-9.76	12.56
NT_11_JUL27H16	-50.84	4.25
NT_11_AUG10H13	-19.37	-4.29
NT_11_MAR02H21	-11.97	16.71
Average Loss Reduction of 5 Cases:		2.898

- WECC loss savings substantially higher than NTTG savings
- net increase in losses for NTTG footprint

NTTG Order 1000 Metrics
Non-PCM Metrics for 2012 Filing

- **MSTI example – Detailed Losses**

TP		Δ Loss (MW)				
		NT_11_OCT4H21	NT_11_DEC22H18	NT_11_JUL27H16	NT_11_AUG10H13	NT_11_MAR02H21
Benefit By TP		**Δ Loss (MW)**	**Δ Loss (MW)**	**Δ Loss (MW)**	**Δ Loss (MW)**	**Δ Loss (MW)**
PacifiCorp		-2.39	-2.23	-9.95	-3.88	2.49
PGE		-0.36	0.65	0.46	0.42	0.96
Northwestern		-0.99	-0.29	-5.74	-0.55	-1.18
Idaho Power		-11.01	14.45	19.55	-0.25	14.45
Deseret		0.01	-0.02	-0.07	-0.03	-0.01
NTTG		**-14.74**	**12.56**	**4.25**	**-4.29**	**16.71**

NTTG Order 1000 Metrics Non-PCM Metrics for 2012 Filing

- **MSTI example – Energy Losses**

  Average of 5 cases:

TP	Avg. Δ Loss (MW)	Estimated Annualized (MWh)[1]	Annualized Benefit($)
PacifiCorp	-3.192	-27961.92	$ (1,006,629.10)
PGE	0.426	3731.76	$ 134,343.36
Northwestern	-1.75	-15330	$ (551,880.00)
Idaho Power	7.438	65156.88	$ 2,345,647.68
Deseret	-0.024	-210.24	$ (7,568.64)

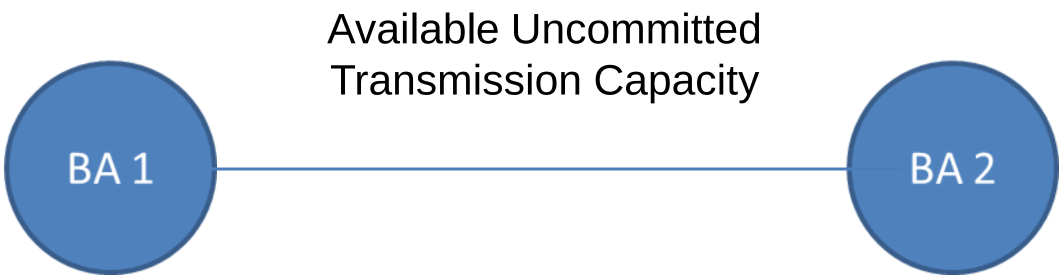
Net increase in losses for NTTG footprint, no loss benefit

[1] assumes $36/MWh annual average energy value

NTTG Order 1000 Metrics
Non-PCM Metrics for 2012 Filing

- Contingency Reserve
  - Metric Assumptions:
    - By balancing area
    - Requirement based on incremental load/gen
    - Future Reserve covered by Simple Cycle Frame F units
    - Reserve event energy priced at BA gas price (2022 TEPPC PC0)
    - There uncommitted transmission capacity available
  - Treated as a capacity sharing opportunity, not a production cost problem
  - Calculation
    - Spreadsheet
    - A 4 BA analysis has 28 combinations or scenarios
    - Most tedious effort is mapping BA to BA topology

Contingency Reserve Standalone

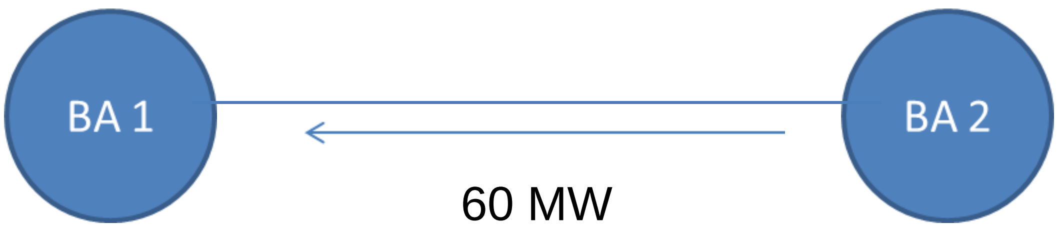


Incremental Gen	1000
Reserve	60
Reserve Cost	$37M
Annualized	$6.1M
Event Energy	$180k

Incremental Gen	500
Reserve	30
Reserve Cost	$18.3M
Annualized	$3.1M
Event Energy	$72k

Contingency Reserve Sharing Scenario 1

Sharing	60
Reserve Cost	$37M
BA 1	67%
BA 2	33%



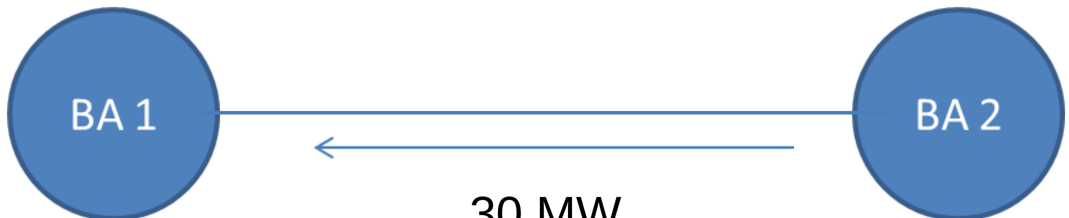
60 MW
Available Uncommitted Transmission Capacity

Reserve Cost	$24.4M	Reserve Cost	$12.2M
Transmission	$21.6M	Transmission	-
Annualized	$7.8M	Annualized	$2.1M

Net Savings $(513k)

Contingency Reserve Sharing Scenario 2

Sharing	60
Reserve Cost	$37M
BA 1	67%
BA 2	33%

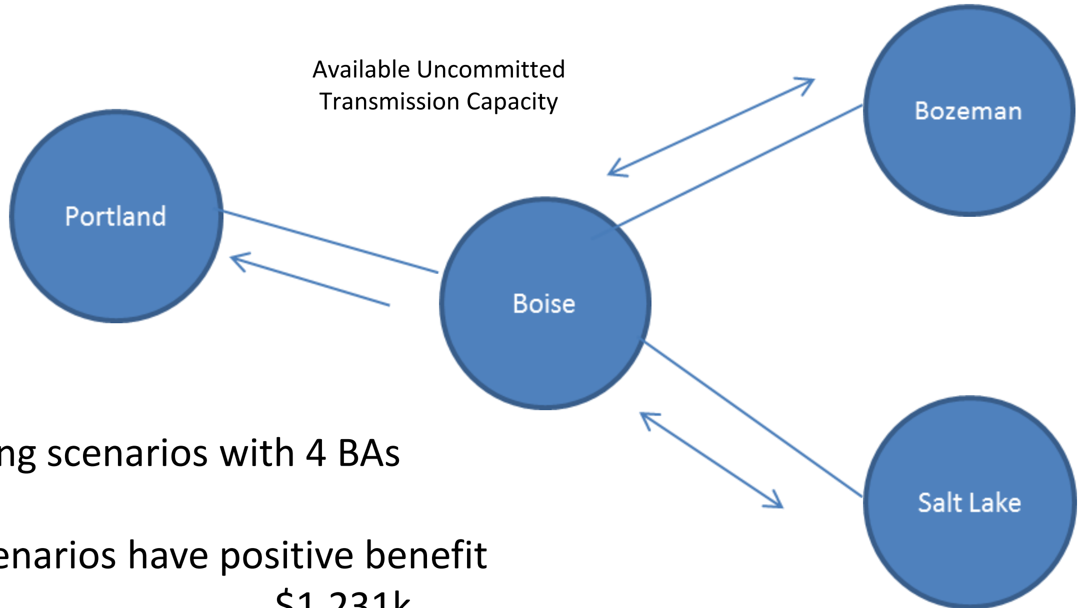


30 MW
Available Uncommitted
Transmission Capacity

Reserve Cost	$24.4M	Reserve Cost	$12.2M
Transmission	-	Transmission	$10.8M
Annualized	$4.2M	Annualized	$3.9M

Net Savings $1,231k

Contingency Reserve Simplified NTTG Region



28 different sharing scenarios with 4 BAs

Only 3 sharing scenarios have positive benefit

• Boise-Bozeman	$1,231k
• Salt Lake-Boise	$3,339k
• Salt Lake-Boise-Bozeman	$3,188k

Based on the assumed resource cost sharing, only the BA not requiring transmission sees savings. Parties requiring transmission would need transmission cost recognition in their respective reserve capacity shares to achieve these scenario savings for all parties.

NTTG Order 1000
Next Steps

Next Steps

- Regional and local transmission planning: October 11, 2012
- Regional cost allocation: October 11, 2012
- Inter-regional transmission coordination process and cost allocation methods: April 11, 2013