Topics Covered

- Technical Analysis Committee-Objectives
- Study Plan
- Project Cost Development
- Power Flow Study
- Upcoming Work/Schedule

Appendix:
- Technical Analysis committee process
- Loads And Resources Scenario
- Cost Assumptions
- Transmission alternative Details
- Power Flow Study Details
Objectives

- Evaluate transmission alternatives to access renewable resources in the Pacific Northwest, British Columbia.
- Determine the transmission impacts and costs of such alternatives.
- Seek stakeholder input on the analysis and scope of the project alternatives.
- Identify the preferred plan of service for the construction of a transmission path from Canada and the Pacific Northwest to a terminal in Northern California with a potential capability of importing up to 3000 MW of renewable and other resources to Northern California.
- Develop the preliminary path ratings for the proposed facilities.
- Determine the interactions with the existing WECC paths.

Note: Summary of Technical Analysis committee process in meeting the objective are listed in Appendix
Study Plan

- Completed Study plan incorporates the comments received from TAC.

- Study Plan covers:
  - Alternatives/Scenarios development
  - Transmission facility cost estimates
  - Assumptions and base case development
  - Power flow study for 15 critical outages in the West
  - Documentation of results
  - Schedule and hand-offs to stakeholders
Transmission Facility Cost Estimates

- Presented by scenario, where a scenario is a combination of resources and transmission facilities necessary to receive and deliver those resources

- Basis:
  - The potential development (MW) for various resource areas in Canada and the Northwest provided by the L&R Committee
  - The major inland and submarine cable options between Canada and California under consideration
  - Develop options for reinforcements within Canada and Northern California
Transmission Option Development

A total of twelve transmission options were developed for transmission project cost estimating purposes

- Inland options:
  - Eight AC options with 500 KV or 765 kV connections
  - Two HVDC option with 500 KV Bi Pole HVDC facilities
  - Hybrid option with EHV AC and HVDC connections
- Submarine cable option comparing of HVDC undersea cable between Allston and SF Bay Area

- Six transmission options for connection with California to deliver capacity to load centers in Northern California

Note: A detailed description for these option shown in Appendix (Slides19-20)
Major Transmission Alternatives
### Preliminary Draft for Discussion Purpose: WECC Regional Planning Review -

All numbers are preliminary estimates based upon various assumptions listed in Appendix (Slide 21)

Estimates are subject to change based upon subsequent information or analyses and do not include feasibility considerations

Project EDRO 2015-2016. All cost in 2006 dollar value in billions

Except where noted the project line cost is for the line from Canadian border Sub (Selkirk) to Northern California border substation (Raven)

The cost shown here does not include: Local area reinforcement cost in Pacific Northwest, BCTC or in Northern California. Cost details for these are shown in Appendix (Slide 25)

<table>
<thead>
<tr>
<th>Connection</th>
<th>Transmission Option</th>
<th>Number of Circuit</th>
<th>Import Capability MW</th>
<th>Transmission Line Distance in Miles</th>
<th>Scenarios</th>
<th>Range of Cost $ Billion</th>
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<tr>
<td>AC 500 KV</td>
<td>Single</td>
<td>1500</td>
<td>700</td>
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<td>Double</td>
<td>3000</td>
<td>700-1180</td>
<td>AC-S1, AC-S2, AC-S3, AC-S5, AC-S6 (Note 1)</td>
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<td>1.7 - 3.2</td>
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<tr>
<td>765 KV</td>
<td>Single</td>
<td>3000</td>
<td>700</td>
<td>AC-S7</td>
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<td>3</td>
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<td>765/500 KV</td>
<td>Double</td>
<td>4500</td>
<td>1230</td>
<td>AC-S4</td>
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<td>4.2</td>
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<td>HVDC</td>
<td>Submarine Cable 500 KV (Note 2)</td>
<td>Bi Pole</td>
<td>1600 650</td>
<td>DC-S10</td>
<td>2.5</td>
<td></td>
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<tr>
<td>Inland Overhead 500 KV (Note 3)</td>
<td>Bi Pole</td>
<td>1500 956</td>
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<td></td>
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<tr>
<td>Inland Overhead 500 KV (Note 4)</td>
<td>Bi Pole</td>
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<td>DC-S11</td>
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<td>Hybrid- AC/HVDC Inland Overhead 500 KV (Note 4)</td>
<td>Double/Bi Pole</td>
<td>3000 956</td>
<td>HY-S13</td>
<td>2.8</td>
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</tbody>
</table>

**Notes**

1. AC-S5 has termination at new Mid C area sub near (Lower Monumental) in Pacific Northwest
2. DC-S10 the submarine cable option has HVDC termination at Allston, SF Bay Area. The cost includes AC reinforcement cost along I5 corridor in Pacific Northwest up to Canadian border Sub (Ingledow)
3. DC-S12 has termination at Tesla sub in Northern California
4. HY-S13 has termination at Tesla sub in Northern California
Power Flow Feasibility Study - Base Case Development for Inland Options

- Benchmark case developed from WECC 2016 HS1A base case with North-to-South flows
- Major path flows represent corner point on NOPSG 2006 NJD Nomogram

- Develop Study Case
  - 500 kV DCTL inserted between Selkirk (BC) and Raven Sub (California) with connections to Tesla and Elverta
  - 3000 MW additional renewable resources added in Canada to fill the line
  - Resources backed down in Northern California
Power Flow Study Cases

- AC-S1 3000 MW import from Canada via 500 kV AC Double Circuit Tower Line - No network connection
- AC-S1 3000 MW import from Canada via 500 kV Ac Double Circuit Tower Line - with network connection at Burns and Mid C area (Lower Monumental Sub)
- AC-S1 3000 MW import from Canada via 500 kV AC Double Circuit tower Line - with network connection only in Mid C area
- HY-S13 3000 MW import from Canada and Pacific Northwest with 500 kV AC connection from Selkirk-Canada to Mid C area-WA and +/-500 kV Bi Pole HVDC line from Mid C area to Tesla Substation-CA

Note: Summary information of the cases, evaluation criteria, contingencies evaluated is shown in Appendix (Slides 28-37)
Preliminary Technical Study Findings for Inland AC Options to PNW/Canada

- Base case flow on the new lines from Selkirk balanced at 1500 MW each.
- Large reactive power requirements to hold the acceptable pre contingency voltage at 500 kV at the terminals and intermediate stations along the new line.
- Dropped 1500 MW of new resources connected to BCTC system for loss of single line and dropped 3000 MW for loss of both of the project lines.
- For the contingencies studied based on the existing switch deck for the outages, the cases converged.
- The existing RAS (Remedial Action Schemes for generation and load drop) for some of the outages studied may be reduced with the possible benefit to increasing existing path ratings.
- For all outages post contingency voltages extremely sensitive to reactive power dispatch-example a 50 MVAR change in reactive power dispatch causes 5-10% voltage change on some 500 kV busses. Post contingency reactive requirements are in the range of 1000-1200 MVAR.
- Network connections to existing AC network in the Pacific Northwest may be needed for voltage control.
- Conducting feasibility study for hybrid option.
Proposed Project Line - Inland AC Option AC-S1
Preliminary TAC Findings

Based on the project line cost and power flow study evaluations to date the findings are:

- **BC-NorCal AC (AC-S1):** Transfer of up to 3000 MW from Canada
  - Not feasible due to voltage regulation issues with no network connections
  - Feasible but flowability problems with network connections
- **Hybrid Option (HY-S13):** Transfers of up to 3000 MW feasible, so far no significant issues.
- **West Coast Cable (DC-S10):** Transfers of up to 1600 MW from Canada are ongoing in the WECC Phase 1 rating process
- **Canada/Midpoint (AC-S3 and AC-S4):** Flowability problems – study on hold
Upcoming Work/Schedule

- **Project Cost Development**
  - Review preliminary project costs
  - Provide update to Economic Analysis Committee (July 2007)
  - Engineering review of unit cost estimates (July-Aug)
  - Update to Economic Analysis Committee (July, 2007)

- **Power Flow Studies**
  - Complete and document results for studies for options AC-S1 (with and without network connection), HY-S13, and HY-S14
  - Coordinate with TANC on Power Flow results for Eastern interconnection option AC S3
  - Coordinate with WCC on Submarine cable option DC-S10
  - Present results to Steering Team (July 2007)

BCTC, PG&E, Sea Breeze and TANC are the primary leads on performing the studies. Additional support from Avista, PacifiCorp, and SPP will be needed for analysis of network connection within their service territories.

- Prepare draft TAC report (Aug/Sep)
Technical Analysis Committee Members

Ben Morris – PG&E – Chair
Don Bain -- Aeropower Services
Scott Waples -- Avista
Allen Hiebert -- BCTC
Amir Amjadi -- BCTC
Chuck Matthews -- BPA
Mike Kreipe - BPA
Rebecca Berdahl -- BPA
Paul Didsayabutra -- CAISO
Barry Flynn -- Flynn RCI
Kip Sikes -- IPC
Frank Cady -- LMUD
Michael Sidiropoulos – PacifiCorp
Tom Tjoelker -- PacifiCorp
Shamir Ladhani – ENMAX
Bangalore Vijayraghavan -- PG&E
Robert Jenkins -- PG&E
Sherman Chen -- PG&E
Philip Augustin -- PGE
Ellen Feng -- Powerex
Gordon Dobson-Mack -- Powerex
Chris Reese -- PSE
Hugh Nguyen -- PSE
Dana Cabbell - SCE
Vishal Patel -- SCE
Rod Lenfest -- Sea Breeze
Joe Tarantino -- SMUD
Paul Schmidt -- SPP
Bryan Greiss -- TANC
Dave Larsen -- TANC
Bill Hosie -- TransCanada
Mariam Mirzadeh -- WAPA
Morteza Sabet -- WAPA
Sam Kwong -- Williams
Appendix
Technical Analysis Committee – Process

- Approximately 30-members of TAC
- Hosted five web meetings since January
- Many meetings/phone call with individual members of the TAC
- Periodic emails sent to TAC members appraising TAC members of project cost development and base case development
- Another web meeting will be coming up by end of August, 2007
Loads and Resources Working Group

- Wind: 1,000 MW
- Biomass: 1,500 MW
- Hydro: 380 MW
- Hydro: 900 MW, Wind: 1,400 MW
- Oil Sands Cogen: 3,500 MW
- Coal: 2,000 MW
- Coal: 1,000 MW
- Wind: 2,700 MW, Wind: 1,000 MW
- Wind: 3,000 MW
- Wind: 2,000 MW
- Geothermal: 200 MW, Biomass: 50 MW

Canada Resources
Northwest U.S. Renewables
Preliminary Draft for Discussion

Purpose
WECC Regional Planning Review
Pacific Northwest/Canada - Northern California Transmission project

Scenario Description
Based on Resource Development in BC, Alberta, Pacific Northwest and Eastern Nevada

Scenario Development

AC-S1  3000 MW from Canada  500 kV AC Double Circuit Tower Line (DCTL)

AC-S2  1500 MW from Canada and
1500 MW from Pacific Northwest (750MW WA State-MID C Area, 750 MW from
Burns OR) 500 kV AC Double Circuit Tower Line AC Double Circuit Tower Line (DCTL)

AC-S3  1500 MW from Canada Via 500 kV AC Single Circuit Tower Line (SCTL) and
1500 MW from Eastern Nevada/Idaho- 500 kV AC Single Circuit Tower Line (SCTL)

AC-S4  1500 MW from Canada via 765 kV AC Single Circuit Tower Line (SCTL) and
1500 MW from Eastern Nevada/Idaho - 500 kV AC Single Circuit Tower Line (SCT)

AC-S5  3000 MW from Pacific Northwest (1500MW WA State-Mid C Area, 1500 MW )
from Burns OR) 500 kV AC Double Circuit Tower Line (DCTL)

AC-S6  3000 MW from Canada Two 500 kV AC Single Circuit Tower Line (SCTL)

AC-S7  3000 MW from Canada via 765 kV AC Single Circuit Tower Line (SCTL)

AC-S8  1500 MW from Canada via 500 kV AC Single Circuit Tower Line (SCTL) - Selkirk-Tesla

DC-S10  1600 MW from Allston OR to San Francisco CA with DC Terminal at Allston, Martin and
Newark with AC with connection to BC to access renewable resources +/- 500 KV HVDC Undersea Cable

DC-S11  3000 MW import via +/- 500 kV Bi Pole HVDC line from Selkirk BC to Ravens Sub in Northern California

DC-S12  1500 MW import via +/- 500 kV Bi Pole HVDC line from Selkirk BC to Tesla Sub in Northern California

HY-S13  3000 MW from Canada and Pacific Northwest Hybrid- 500 kV AC and 500 kV Bi Pole HVDC
California Interconnection Options

CA 1  500 kV lines from Raven to Elverta (Zeta1) with one line by passing Elverta on to Tesla. The DCTL portion of the line from Raven Sub will be routed close to Round Mountain-Cottonwood substation. No connection will be established at Round Mountain or Cottonwood.

CA 2  500 kV line from Raven to Elverta (Zeta1) and a 500 kV line from Raven-Table Mountain-Tesla with connection at Table Mountain. The route will be to east of existing 500 kV line between Table Mountain and Tesla Sub.

CA 3  500 kV line from The Raven - Elverta (Zeta1) and a 500 kV line from Raven-Bellota-Sunol – Tesla. The route is in the foot hills of Sierra Mountain range.

CA 4  500 kV line from Raven-Elverta (Zeta1) and a 500 kV line from Raven to Tesla by passing Table Mountain Sub

CA 5  500 kV line from Raven-Tesla Via Table Mountain sub

CA 6  500 kV AC line from Tesla to Elverta (Based on 3000 MW HVDC link between Mid C area and Tesla sub in CA)
Assumptions for Transmission Cost Development

Assumptions:

1) Uniform cost for ROW for 500 KV lines in Canada/Pacific Northwest/Nevada
2) Cost of ROW in CA 1.5 time the cost of ROW in Canada/Pacific Northwest/Nevada
3) For over land transmission line assume homogenous line construction throughout the transmission corridor
4) Cost for ROW for 765 kV is 1.0 times the cost of 500 KV line ROW
5) Maximum rating for Single Circuit Transmission Line (SCTL)-500 kV is 1500 MW
6) Maximum rating for Double Circuit Transmission line (DCTL)-500 kV is 3000 MW
7) Maximum rating for a single circuit 765 kV line is 3000 MW
8) Bi Pole DC Line Voltage rating +/- 500 kV
9) Bi Pole DC line capacity 1500 or 3000 MW
10) Mileage for the new transmission line to California were based on straight line measurement and increased by 15 percent to accommodate routing issues.
11) Cost for 500 kV Double Circuit Tower Line is 160% the cost of single circuit tower line
12) Cost for 765 kV Single Circuit Tower line is 130% the cost for 500 kV DCTL
13) The new transmission lines will be series compensated assume one bank per terminal bank per line segment with normal rating of 2667 Amps
14) Each 500/230 kV or 765/230 kV transformer bank 1134 MVA bank comprises of three single phase units (Non Firm Bank)
15) Static Var Compensator for 500 and 765 kV.
16) Cost for other 765 kV station equipment 130% the cost of 500 kV equipment
17) Transmission cost plans based on resource scenario development
18) The project cost represented here does not include the permitting and environmental mitigation and cost.
19) For inland AC options a switching station or substation is assumed every 175-225 miles
20) The local transmission upgrade cost does not include the cost to connect generation resources to the grid.
21) Due to lack of specific information on size and exact location of generation resources, generation interconnection cost is not derived at this time- thus all the tab with GI are left blank
22) CA SF Bay area reinforcement cost of $0.5 billion is included for all scenarios
23) BCTC system upgrade cost: Is dependent upon resources location. For this analysis it is assumed 1600 MW connected to Skeena 500 kV and 1100 MW connected to GM Schrum 500 kV. This will require a new 500 kV line form Skeena to Williston and a new 500 kV line from Williston to Kelly Lake
24) If only 600 MW is connected to Skeena 500 kV then a new 500 kV line from Skeena to Williston is not required
25) BCTC system upgrade cost provided by Allen Hiebert in Canadian dollars assume 0.956 conversion rate to US dollars
Potential BCTC Transmission Reinforcement Based on Resource Development
Potential BCTC Transmission Reinforcement Based on Resource Development
Potential Transmission Reinforcement Options for Northern California
### Transmission System Component Cost - does not include resource interconnection cost to the bulk transmission system

**Preliminary Draft for Discussion; Purpose: WECC Regional Planning Review**

Pacific Northwest/Canada- Northern California Transmission project - Transmission Asset Cost Analysis

All numbers are preliminary estimates based on listed assumptions.

Estimates are subject to change based upon subsequent information or analyses and do not include feasibility considerations.

**Project EDRO 2015-2016**

*All cost in ,000 2006 Dollar value*

<table>
<thead>
<tr>
<th>Scenario</th>
<th>Transmission Option</th>
<th>Import Capability MW</th>
<th>Project Transmission Distance to CA Terminal in Miles</th>
<th>Incremental Resources Located in</th>
<th>Project Cost Canada/Pacific Northwest/Nevada to CA Border</th>
<th>BCTC System Reinforcement Cost (Note 3)</th>
<th>Local area Reinforcement Cost in Pacific Northwest (Note 4)</th>
<th>California Reinforcement Cost (Note 5)</th>
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<tbody>
<tr>
<td>AC-S1</td>
<td>500 KV AC DCTL</td>
<td>3,000</td>
<td>708</td>
<td>Canada</td>
<td>2,537,658</td>
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<td>0</td>
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<td>AC-S2</td>
<td>500 KV AC DCTL</td>
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<td>708</td>
<td>Canada and Pacific Northwest</td>
<td>2,255,466</td>
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<td>AC-S3</td>
<td>500 KV AC</td>
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<td>1,176</td>
<td>Canada and Eastern Nevada</td>
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<td>765&amp; 500 KV AC</td>
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<td>DC-S10</td>
<td>(Allston-S Bay)</td>
<td>500 KV HVDC (submarine cable)</td>
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<td>650</td>
<td>Canada</td>
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<td>HY-S13</td>
<td>500 KV and +/- 500 kV HVDC</td>
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<td>956</td>
<td>Canada and Pacific Northwest</td>
<td>2,831,599</td>
<td>1,230,920</td>
<td>93,500</td>
<td>354,000</td>
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</tbody>
</table>
1) For all scenarios evaluated transmission distance is length of bulk power line for delivery from Canada (Selkirk Substation)/ Pacific Northwest to the California Border substation at Raven. Exceptions are scenario DC-S10 delivery to SF Bay area sub from Allston Sub, DC-S11 and HY-S13 the delivery is to Tesla Sub in Northern California.

2) For most scenarios the project cost is the cost for the bulk power transmission line from Canada-Selkirk substation or to the proposed Northern California border Raven substation with the exception of DC-S12 and HY-S13 which has delivery point at Tesla Sub.

3) BCTC cost can be divided into two components system reinforcement cost and connection cost of the project line to the local substation such as Selkirk or Nicola sub. BCTC reinforcement costs are dependent on location and magnitude of resource development. Based on preliminary review BCTC has identified two major 500 kV reinforcements to the system to deliver up to 3000 MW of resources to delivery point at Selkirk. These are new 500 kV line from Skeena-Williston (281 miles) for delivery of 1600 MW of resources along the northwestern coast and 5000 kV line from Williston-Kelly Lake (206 miles) for delivery of 1600-2600 MW of resources located along the northwestern coast and in the Peace River area. The connection cost identified for the project is the 500 kV banks and local substation connection cost for the project line.

4) At this time for most of the scenarios studied the local area reinforcement cost in the Pacific Northwest is limited to 500/230 kV banks and substation equipment to connect the project line and the 500/230 kV transformer banks, exception being scenarios DC-S10, DC-S11,DC-S12 and HY-S13.

5) Based on the timing of this project line, only a portion of the California connection cost identified (approximately ($1.5 billion) for delivery 3000 or 1500 MW capacity to the load centers in the SF Bay area may be applicable for project evaluation. It is anticipated prior to the completion of the project line, due to local area resource development in Northern California and supply reliability requirements in the SF Bay area some of the transmission reinforcements identified in the project cost development maybe built and be in service this includes $500 million for SF bay area supply and TANC proposal for transmission line from Round Mountain to ZETA 1 sub near existing Elverta sub.

6) For scenario DC-S10 (WCC) option the cost includes upgrade cost in Pacific Northwest and BCTC delivery at Nicola sub. These upgrades were identified in the NTAC study (option 3A).
Resource Additions Modeled in Canada

- 600 MW BC Coastal wind at Skeena 500 kV
- 250 MW Vancouver Island wind at Dunsmuir 500 kV
- 1100 MW wind and Site C hydro at Peace Canyon 500 kV
- 300 MW Small hydro at Ashton Creek 500 kV
- 750 MW other renewable resources in BC and Alberta represented at Cranbrook 500 kV
500 kV DCTL Model

- Approximately 50% series compensation
- Base Cases with and without network connections between Selkirk and Raven
- Intermediate 500 kV stations at Spokane, Mid-C, and Burns to collect generation
- Synchronous condensers modeled at intermediate 500 kV stations for voltage control (to be replaced later with static var devices)
- Line shunt reactors for light load conditions
# Major Path Flows for Benchmark and Project Base Cases without Network Connection in Pacific Northwest

<table>
<thead>
<tr>
<th>#</th>
<th>Path Name</th>
<th>Path Rating</th>
<th>2016 HS1A</th>
<th>Benchmark Case</th>
<th>Project Case AC S1</th>
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<tr>
<td>3</td>
<td>Northwest – Canada</td>
<td>3150 MW (n2s)</td>
<td>2302 MW (n2s)</td>
<td>3150 MW (n2s)</td>
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<td>Northern – Southern Calif.</td>
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<td>PDCI</td>
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<td>COI</td>
<td>4800 MW (n2s)</td>
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<td>73</td>
<td>North of John Day</td>
<td>8400 MW (n2s)</td>
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<td>7800 MW (n2s)</td>
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<td>75</td>
<td>Midpoint – Summer Lake</td>
<td>1500 MW (e2w)</td>
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<td>N/A</td>
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## Critical Contingencies Evaluated

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<th>No.</th>
<th>Description</th>
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<tbody>
<tr>
<td>1.</td>
<td>Proposed project Canada/PNW – Northern California DLO (all sections)</td>
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<tr>
<td>2.</td>
<td>Palo Verde Double-Unit Outage</td>
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<td>3.</td>
<td>PDCI Bipole Outage</td>
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<td>5.</td>
<td>San Onofre Double-Unit Outage</td>
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<td>6.</td>
<td>Malin – Round Mt DLO</td>
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<td>7.</td>
<td>Round Mt – Table Mt DLO</td>
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<td>8.</td>
<td>Table Mt South DLO</td>
</tr>
<tr>
<td>9.</td>
<td>Vaca Dixon – Tesla /Table Mt – Tesla DLO</td>
</tr>
<tr>
<td>10.</td>
<td>Tesla – Metcalf /Tesla – Los Banos DLO</td>
</tr>
<tr>
<td>11.</td>
<td>Tesla – Metcalf /Tesla – Tracy DLO</td>
</tr>
<tr>
<td>12.</td>
<td>Critical DLO with in existing system in Pacific Northwest and Canada - TBD</td>
</tr>
</tbody>
</table>
Evaluation Criteria

- All lines within the appropriate ratings per WECC planning standard
- 500 kV and 230 kV voltages maintained at appropriate levels during normal and contingency operation per WECC planning standard
- Governor Power flow solution for contingencies
- For loss of some 500 kV line within BCTC system drop generation
- Loss of a section of the project line drop up to 1500 MW of generation
- For Double line outage of project line drop up to 3000 MW of generation
# Desired Major Path Flows for Benchmark & Project case with network connection

<table>
<thead>
<tr>
<th>#</th>
<th>Path Name</th>
<th>Path Rating</th>
<th>2016 HS1A</th>
<th>Benchmark Case</th>
<th>Project Case</th>
<th>Project Case with LM Connection</th>
</tr>
</thead>
<tbody>
<tr>
<td>3</td>
<td>Northwest – Canada</td>
<td>3150 MW</td>
<td>2302 MW</td>
<td>3150 MW (n2s)</td>
<td>3150 MW (n2s)</td>
<td>3153 MW (n2s)</td>
</tr>
<tr>
<td></td>
<td></td>
<td>(n2s)</td>
<td>(n2s)</td>
<td>(n2s)</td>
<td>(n2s)</td>
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</tr>
<tr>
<td>26</td>
<td>Northern – Southern Calif.</td>
<td>4000 MW</td>
<td>2185 MW</td>
<td>4000 MW (n2s)</td>
<td>4000 MW (n2s)</td>
<td>4000 MW (n2s)</td>
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<td></td>
<td></td>
<td>(n2s)</td>
<td>(n2s)</td>
<td>(n2s)</td>
<td>(n2s)</td>
<td></td>
</tr>
<tr>
<td>65</td>
<td>PDCI</td>
<td>3100 MW</td>
<td>2980 MW</td>
<td>2850 MW (n2s)</td>
<td>2850 MW (n2s)</td>
<td>2850 MW (n2s)</td>
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<td></td>
<td></td>
<td>(n2s)</td>
<td>(n2s)</td>
<td>(n2s)</td>
<td>(n2s)</td>
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</tr>
<tr>
<td>66</td>
<td>COI</td>
<td>4800 MW</td>
<td>3776 MW</td>
<td>4400 MW (n2s)</td>
<td>4400 MW (n2s)</td>
<td>4521 MW (n2s)</td>
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<td></td>
<td></td>
<td>(n2s)</td>
<td>(n2s)</td>
<td>(n2s)</td>
<td>(n2s)</td>
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<tr>
<td>73</td>
<td>North of John Day</td>
<td>8400 MW</td>
<td>7949 MW</td>
<td>7800 MW (n2s)</td>
<td>7808 MW (n2s)</td>
<td>7839 MW (n2s)</td>
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<td>(n2s)</td>
<td>(n2s)</td>
<td>(n2s)</td>
<td>(n2s)</td>
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</tr>
<tr>
<td>75</td>
<td>Midpoint – Summer Lake</td>
<td>1500 MW</td>
<td>85 MW (w2e)</td>
<td>236 MW (w2e)</td>
<td>247 MW (w2e)</td>
<td>237 MW (w2e)</td>
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<td>(e2w)</td>
<td>(w2e)</td>
<td>(w2e)</td>
<td>(w2e)</td>
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<tr>
<td>76</td>
<td>Alturas Project</td>
<td>300 MW</td>
<td>263 MW</td>
<td>264 MW (n2s)</td>
<td>259 MW (n2s)</td>
<td>265 MW (n2s)</td>
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<td></td>
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<td>(n2s)</td>
<td>(n2s)</td>
<td>(n2s)</td>
<td>(n2s)</td>
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<tr>
<td>666</td>
<td>BC – California (North)</td>
<td>3000 MW</td>
<td>N/A</td>
<td>N/A</td>
<td>3000 MW (n2s)</td>
<td>2998 MW (n2s)</td>
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<td>(n2s)</td>
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<td></td>
<td>(n2s)</td>
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</tr>
</tbody>
</table>
**Power Flow Study (One Network Connection in Pacific Northwest) - Preliminary Findings Option AC-S1**

Assuming a connection is established in the Mid C area (Lower Monumental Sub) following are some preliminary findings:

- Preliminary finding show even by increasing the series compensation on the project lines to 70 percent there is not much flow from Pacific Northwest AC network on to the project lines

- High reactive power requirements to hold the pre contingency voltages of 1.05 PU at 500 kV at the terminal and intermediate stations along the new line.

- All contingencies converged based on the existing switch deck for the outages.

- Assumed generation dropping scheme for loss of the sections of the proposed project line. Dropped 1500 MW of new resources connected to BCTC system for loss of single line and dropped 3000 MW for loss of both of the project lines

- The existing RAS (generation and load drop) for some of the outages studied maybe reduced with the possible benefit of increasing existing path ratings.

- Continuing further evaluations of this option
## Series Compensation with Network Connections at Burns and Lower Monumental (Mid C area)

<table>
<thead>
<tr>
<th></th>
<th>Benchmark Case</th>
<th>Burns Connection</th>
<th>Burns &amp; Lower Monumental Connection</th>
</tr>
</thead>
<tbody>
<tr>
<td>MALIN – ROUND MT #1&amp;2</td>
<td>62%</td>
<td>0%</td>
<td>0%</td>
</tr>
<tr>
<td>CAPTJACK - OLINDA</td>
<td>62%</td>
<td>62%</td>
<td>56%</td>
</tr>
<tr>
<td>JOHN DAY - CAPTJACK</td>
<td>54%</td>
<td>0%</td>
<td>54%</td>
</tr>
<tr>
<td>JOHN DAY - MALIN</td>
<td>53%</td>
<td>33%</td>
<td>53%</td>
</tr>
<tr>
<td>GRIZZLY – MALIN #1</td>
<td>79%</td>
<td>79%</td>
<td>56%</td>
</tr>
<tr>
<td>SUMMER L – BURNS - MELBA</td>
<td>49%</td>
<td>0%</td>
<td>0%</td>
</tr>
</tbody>
</table>
Power Flow Study (Two Network Connections in Pacific Northwest) - Preliminary Findings Option AC-S1

Assuming connections are established at Burns and Mid C area (Lower Monumental Sub) following are some preliminary findings:

- Requires bypassing series compensation on the existing 500 kV lines in Pacific Northwest to keep the flows on the existing paths within their ratings.
- May require Phase Shifter at Burns to get acceptable flows between the project lines and the existing AC network in Pacific Northwest.
- Need to investigate other interconnection points for Pacific AC network in Oregon.
Proposed Project Line - Inland Hybrid Option HY S13

[Map showing the proposed project line from Selkirk to Tesla with various substations and power lines marked.]