WECC Regional Planning Review

Canada/Pacific Northwest – Northern California Transmission Line Project

Technical Analysis Committee Report

November 1, 2007

Table of Content

Summary.....1

SECTION 1 Background and Objevtives.....5

SECTION 2 Study Plan and aAlternative Development.....8

SECTION 3 Prelimiary Cost Estimates.....13

SECTION 4 Preliminary Techincal Study 20

SECTION 5 Stakeholder Comments and TAC Response.....31

SECTION 6 Findings and Recommendations.....38

Attachment 1 41
Attachment 2.1 42
Attachment 2.2 42
Attachment 3.1 44
Attachment 3.2 46
Attachment 3.3 47
Attachment 3.4 48
Attachment 4.1 50

Summary

On August 16, 2006, PG&E initiated a WECC Regional Planning Review for a proposed British Columbia-Northern California transmission line project. One of the objectives of the regional planning review was to evaluate the feasibility of this new transmission project to access 1600-3000 MW of potential incremental renewable resources from British Columbia, Canada (BC) and the US Pacific Northwest for delivery into Northern California. As a part of the regional planning review, a Technical Analysis Committee (TAC) was formed. Membership for this committee was solicited and was comprised of stakeholders from throughout the region. Thirty members signed up for this committee representing various entities (see Attachment 1).

The regional planning studies have concluded and the TAC recommends that the Hybrid alternative, described in additional detail below, be considered in Phase 1 of the WECC Project Rating Review Process

The TAC developed thirteen alternatives encompassing overland HVAC connections, overland HVDC connections and overland and undersea HVAC/HVDC (Hybrid) connections to BC Canada, Pacific Northwest and Idaho having transfer capabilities ranging from 1500 MW to 4500 MW. The analysis (power flow and cost estimates) was prepared on behalf of the TAC by PG&E, TANC (alternatives to Idaho), and Sea Breeze Corporation (undersea cable)

Power Flow Studies

Technical feasibility studies (Power Flow) for a few of the lowest cost HVAC and Hybrid alternatives were completed. The studies showed that an HVAC alternative for 3000 MW capacity transfer from Selkirk Substation in southeast BC to Tesla Substation in Northern California without network interconnection to the Pacific Northwest transmission network is not a feasible alternative.

The studies showed a HVAC alternative with network connections in the Pacific Northwest near Lower Monumental and Burns has an adverse impact on the existing Pacific AC Intertie –PACI in that the existing series compensation will need to be reduced in order to accommodate the 3000 MW capacity transfer on the Project line, with possible negatives impact to the Operating Transfer Capability (OTC) of the existing PACI.

One alternative considered for mitigating the adverse impact of AC interconnection is to establish additional ties between the Project line and existing PACI facilities, and changing series compensation on the existing PACI in order to achieve balanced flow along the existing PACI and Project line facility. The cost estimates for HVAC alternatives includes the cost of facility upgrades required to achieve the desired system performance for the AC alternative. This alternative was found to be effective in the

NTAC studies with a 1500 MW tie line between Pacific Northwest and Northern California.

The last alternative considered a hybrid interconnection for the Project. The hybrid alternative is a combination of HVAC and HVDC facilities between Selkirk Substation and the termination substation at Raven or Tesla with HVAC and HVDC ties to the existing network in the Pacific Northwest. The studies show that this alternative is technically feasible and did not result in adverse impacts on the existing system.

Cost Estimates

The transmission cost analysis was based on a set of design assumptions and unit cost data. This cost analysis includes (1) the Project Facility Cost (cost of the new transmission facilities between Selkirk or Ingledow Substation in BC to a termination station in Northern California at either Raven or Tesla Substation depending upon the alternative) and the Network Upgrade Cost (any additional costs in BC, the Pacific Northwest or California to transfer generation from source to sink). The sum of these costs provides the total cost from source-to-sink as summarized in the following table:

Import Capability in MW	Source-Sink Cost[1] ($ billions)		
	HVAC	HVDC	Hybrid
1500-1600	4.6	4.1-4.4	
3000-4500	5.5-7.2	5.5	4.7-5.2

In reviewing these cost estimates it should be noted that:

- The BCTC upgrades and associated costs may be embedded in the BCTC transmission rate for delivery of BC resources to Selkirk or Ingledow Substation.

- The Pacific Northwest upgrade cost includes the 500/230 KV transformer banks and terminations at intermediate stations along the Project line. It does not include any system impact cost to interconnect with the Project line. Upon completion of WECC Phase 1 rating studies establishing a preliminary plan of service, these costs may change and will be revised accordingly.

- Some of the transmission reinforcements identified for Northern California to deliver the incremental resources from the Project line termination south of Raven or Tesla Substations could be in service before the Project operational date of 2015, and therefore be viewed as a sunk cost.

[1] *The cost estimates in the table are based on unit cost and not on engineering review and are subject to change based on subsequent information, analyses and further feasibility consideration. The cost estimates do not include any cost associated with permitting issues. The cost estimates are in 2006 dollar value and don not include escalation.*

A summary of detailed cost analysis for each alternative is shown in the Table 3.2 of this report.

Recommendation

Based on the findings from this work, TAC recommends that the Hybrid transmission line alternative be further evaluated in Phase 1 of the WECC Project Rating Review Process. The conceptual project description for the WECC Phase 1 Rating study shown in Figure 1 is described below:

- A combination of 500 kV AC double circuit tower line +/-500 kV bi pole HVDC line with HVDC termination at Tesla sub
- Proposed rating: up to 3000 MW, north to south
- Terminations at Selkirk substation in BC, Canada and Tesla/Tracy substations in Northern California
- Potential intermediate connections pending results of the Phase 1 study:
    - AC connection in the Spokane area in WA (as an example Beacon or Devil's Gap substation)
    - AC connection at McNary (Lower Columbia area), or Lower Monumental (Lower Snake area) in WA
    - AC interconnection at Grizzly area OR
    - HVDC terminals at McNary or Lower Monumental in WA or at Grizzly area OR
    - Potential third HVDC terminal- Round Mountain Substation

The scope for WECC Phase1 rating process for the preliminary project description listed above is:

- Conduct studies to demonstrate the proposed bi-directional non-simultaneous rating.
- Develop a preliminary Plan of Service

It should be noted that this recommendation does not rule-out the possibility that another alternative could be implemented to access resources in British Columbia or the Pacific Northwest. Completion of technical studies of other transmission projects in Idaho, and eastern Nevada may lead to development of a transmission alternative to Northern California from eastern Nevada and Idaho.

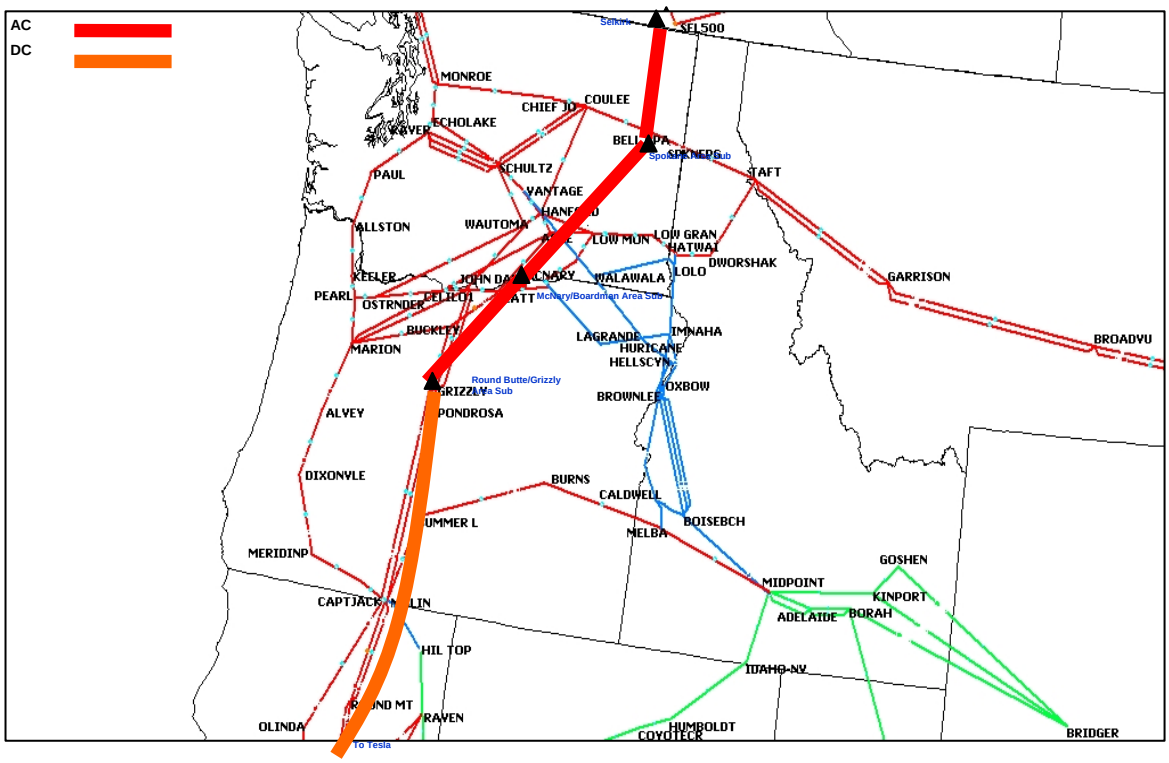


Figure 1: Proposed conceptual transmission plan for WECC Phase 1 Rating Process

SECTION 1

Background and Objectives

Background

On August 16, 2006, PG&E initiated a WECC Regional Planning Review for a possible British Columbia-Northern California transmission line project. The purposes of this regional planning review process are to: (1) Evaluate transmission alternatives to access renewable resources in the Pacific Northwest and British Columbia, (2) Determine the benefits and costs of such alternatives, (3) Seek stakeholder input on the analysis and scope of the project alternatives. As a part of the WECC regional planning review process a number of studies, such as a) technical feasibility, b) economic feasibility and c) environmental feasibility[2] are required to assess the impacts of the proposed transmission interconnections.

In December 2006 a Technical Analysis Committee (TAC) was formed for this transmission project. In addition to the TAC, the Loads and Resource Working Group (L&R) and the Economic Analysis Committee were also formed to provide input to the overall project review process. The organization structure for the WECC regional planning review is shown in the Figure 1.1 below.

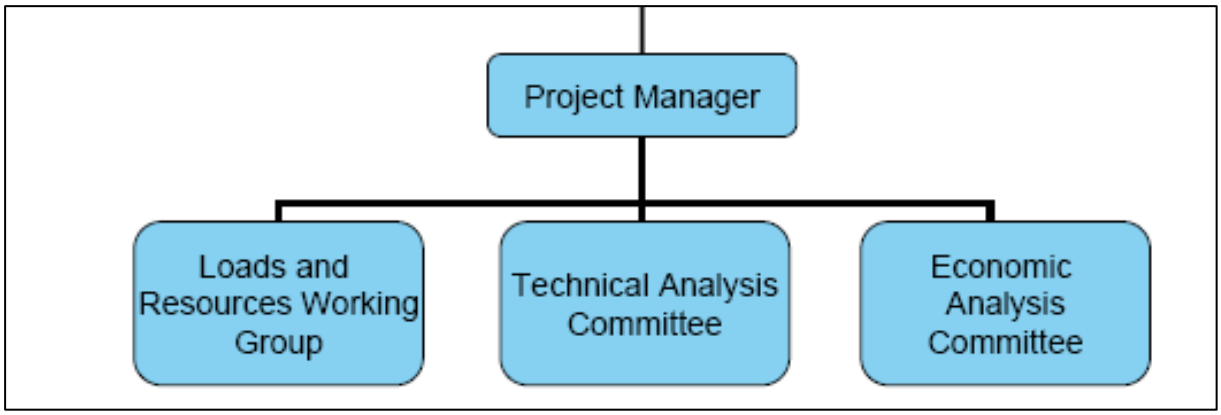


Figure 1.1 Organizational Structure for the WECC Regional Planning Review

Technical Analysis Committee-Objectives

The objectives of the technical studies are to:

- Identify a conceptual plan of service for the construction of a transmission path from Canada/ Pacific Northwest to Northern California with a potential

[2] Environmental feasibility for this project review process will be limited to noting any known environmental impediments to development of this project. Detailed environmental impacts and mitigation measures, if necessary, will be addressed in a future phase of project development.

capability of importing up to 3000 MW of renewable and other resources to Northern California.

- Develop ratings for the proposed facilities.

- Determine interactions with existing WECC paths.

The conceptual plan of service shall be flexible and scalable depending upon development of renewable resources along the proposed transmission path and the points of delivery of such resources. The on-line date for this project is expected to be no earlier than 2015.

Through an open stakeholder process the tasks for the TAC were developed and included:

1) Solicit input from the Loads and Resources working group identifying regions of renewable and other resource developments in Canada, Pacific Northwest and Eastern Nevada.

2) Develop conceptual transmission project alternatives for the transmission lines having connections between British Columbia (BC), Pacific Northwest, Nevada, Idaho and Northern California.

3) Develop cost estimates for these alternatives, including the cost of line and substation work and the cost of local system reinforcements to access renewable resources, to mitigate system impacts, or to provide other regional benefits.

4) Provide input to the Economic Analysis Committee on the cost of transmission project alternatives.

5) Consistent with the WECC regional planning review process, conduct a preliminary power flow study to evaluate the performance of select transmission alternatives.

6) Propose a conceptual plan of service for further study in Phase 1 of the WECC Project Rating Review Process

The Technical Analysis Committee Process

Membership for the TAC committee was solicited and comprised of stakeholders from throughout the region. Thirty members signed up for this committee representing various entities. The list of participating members is shown in Attachment 1 of this report.

In preparing the preliminary project cost estimates and conducting the technical analysis for this project, the information developed by L&R Working Group was considered. Active stakeholder participation was encouraged and a number of conference calls were held to share and discuss ideas to develop transmission project alternatives and study plan.

The committee developed a task list to accomplish the objectives of the study.

Sections two, three and four discuss further the details of the study plan, the alternative development, the cost estimate preparation and preliminary results from the power flow study.

SECTION 2

Study Plan and Alternative Development

Study Plan

A Study plan was developed describing the alternatives to be considered for the transmission project, the basis for development of cost estimates for the alternatives, and the study assumptions and scope for the technical study. The study plan was updated with comments from TAC members and a final draft was shared with the committee in March 2007. The details of the study plan can be found at: \\http:\\www.pge.com\biz\transmission_services\canada\technical_analysis_committee.html.

Transmission Alternative Development

The proposed corridors for transmission line development linking the resource areas with Northern California are shown in Attachment 2.1[3].

As noted from schematics in Attachment 2.1 there are two transmission corridors that were evaluated namely:

- The overland (or inland) corridor from northern California to the North and East
- The undersea corridor from northern California to the North.

The L&R Work Group identified the potential renewable development in Canada and the Pacific Northwest and Nevada shown in the Attachment 2.2 and the potential transmission capacity deficiencies to transfer the incremental resources from these locations to Northern California. Based on input from L&R Work Group and stakeholders, a number of transmission alternatives were developed for evaluation, including HVAC, HVDC and Hybrid–HVAC/HVDC connections for delivery of 1500-4500 MW of incremental resources to the load centers in Northern California.

The proposed terminations for the inland transmission alternatives are at Selkirk Substation (BC) to the north, Midpoint[4] Substation (Idaho) to the east, and Raven[5] or Tesla Substations (Northern California) to the south.

---

[3] In the announcement of Regional Planning Review letter of August 16, 2006, the undersea cable option showed a cable connection north of Allston to terminals in Victoria- BC and further north to Prince Rupert area in BC Canada. However during the TAC review the development of this submarine connection north of Allston was not considered at this time.

[4] The transmission alternatives with AC interconnection to Idaho vai eastern Nevada was proposed by TANC. For this report TAC evaluated the cost of the transmission facilities to Idaho. TANC is responsible for the technical evaluation for this alternative.

Intermediate stations[6] along the project lines are assumed for interconnections to the existing Pacific Northwest AC grid either for regional transmission benefit, for connection to the renewable resources in the region or for siting of series capacitor banks in the transmission project line.

For the inland alternatives the possible intermediate interconnections in Pacific Northwest and Eastern Nevada are:

- Spokane area-WA, potential interconnection at Devils Gap Substation or Beacon Substation,
- Lower Snake area-WA, potential interconnection at Lower Monumental Substation or
- Lower Columbia -WA, potential interconnection at McNary Substation or Boardman Substation-OR,
- Burns area –OR, potential interconnection at Burns Substation
- Grizzly area-OR, potential interconnection at Grizzly Substation or Round Butte Substation
- Eastern Nevada area-NV, possible interconnection at Valmy Substation.

The schematics for the various inland alternatives considered this project review are shown in Figure 2.1 below

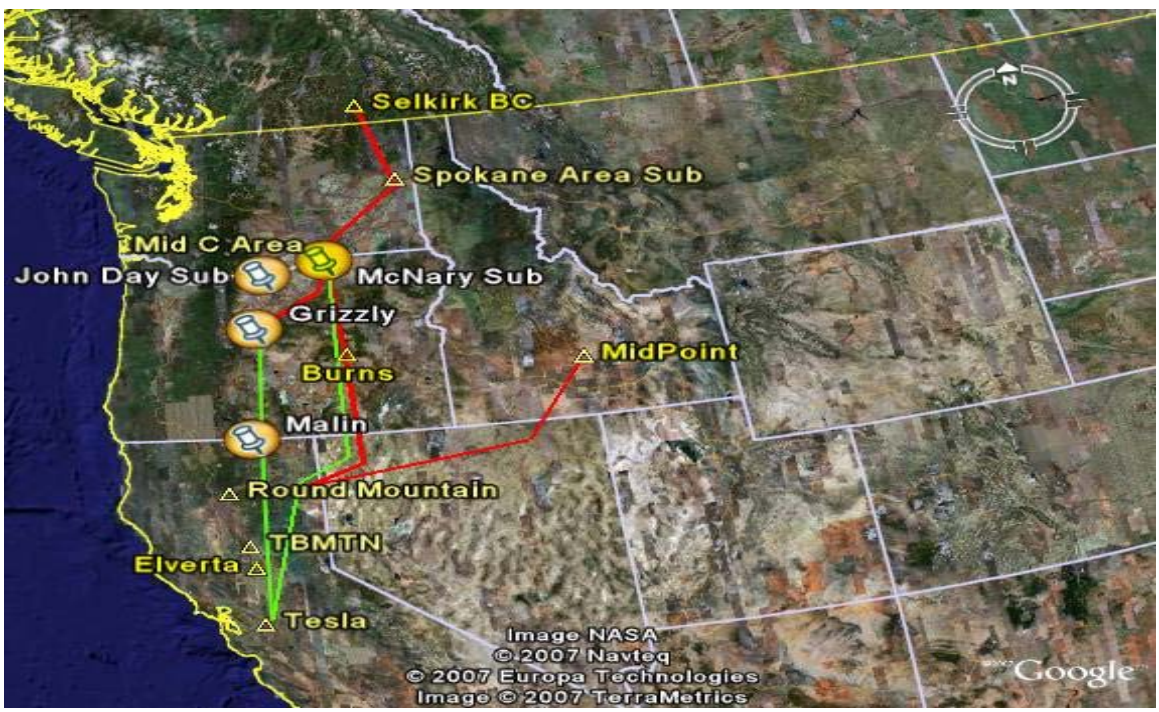


Figure 2,1: Potential HVAC and Hybrid alternative interconnections

---

[5] A Substation in the northeastern part of California in Lassen County is proposed as one of the termination for the transmission project line. For this project review the proposed substation is named as Raven.

[6] An assumption is made for the AC line that will require connection approximately every 250 miles

Figure 2.1/ Inland HVAC and Hybrid alternatives

The undersea alternative considered for this study is the HVDC submarine cable between Allston Substation in Oregon and Martin and Newark substations in the San Francisco Bay area with HVDC terminals at Allston, Martin and Newark substations. This alternative was proposed by Sea Breeze Corporation as the West Coast Cable (WCC) project alternative and is currently being evaluated within the WECC Phase 1 rating study. Sea Breeze Corporation will provide any technical analysis they have carried out for this alternative.

Based on the L&R Work Group report and the proposed transmission Project line connections, the alternatives considered for the project cost evaluation and the power flow evaluations is described in the Table 2.1.

In addition to the transmission project alternatives shown in the Table 2.1, conceptual transmission alternatives within Northern California for the delivery of 1500-4500 MW of import capacity from Canada, Pacific Northwest and Eastern Nevada at proposed Raven substation to the load centers in the Northern California region was also developed. The elements of this conceptual transmission connection for the Northern California system are shown in Table 2.2.

In order to provide an equitable source-to-sink comparison between the inland alternatives and the submarine cable alternative (WCC) for delivery of incremental resources from Canada to Northern California, the transmission upgrades beyond the northern and southern termination points of the Project line were included. For the inland alternative such upgrades are in the SF Bay area and in BC between the BC coast and Selkirk Substation and for the WCC such upgrades are in the Pacific Northwest along the I5 corridor and in the BC system between the BC coast and Ingledow.

Alternative	Description
AC-S1	Import 3000 MW from Selkirk-BC Canada via 500 kV AC Double Circuit Tower Line (DCTL). Intermediate connections Spokane area, Lower Snake area or McNary area-WA Burns area-OR, Raven substation- Northern California.
AC-S2	Import 1500 MW from Selkirk-BC Canada and 1500 MW from Pacific Northwest (750 MW from MID C Area WA, 750 MW from Burns OR) via 500 kV AC Double Circuit Tower Line AC Double Circuit Tower Line (DCTL). Intermediate connections Spokane area, Lower Snake area or McNary area-WA, Burns area-OR, Raven substation-Northern California.
AC-S3	Import 1500 MW from Selkirk-BC-Canada via 500 kV AC Single Circuit Tower Line (SCTL) and 1500 MW from Midpoint substation -Idahovia500 kV AC Single Circuit Tower Line (SCTL). Intermediate connections Spokane area, Lower Snake area or McNary area-WA, Burns area- OR, Valmy area-NV and Raven substation-Northern California.
AC-S4	Import 1500 MW from Selkirk-BC Canada via 765 kV AC Single Circuit Tower Line (SCTL) and 1500 MW from Midpoint-Idaho via 500 kV AC Single Circuit Tower Line (SCTL). Intermediate connections Spokane area, Lower Snake area or McNary area-WA, Burns area-OR, Valmy area-NV and Raven substation-Northern California.
AC-S5	Import 3000 MW from Pacific Northwest (1500MW from Mid C area WA, 1500 MW from Burns OR) via 500 kV AC Double Circuit Tower Line (DCTL). Connections in Spokane area, and intermediate connection in Lower Snake area or McNary area-WA, Burns area-OR, and Raven substation-Northern California
AC-S6	Import 3000 MW from Selkirk-BC Canada via Two 500 kV AC Single Circuit Tower Line (SCTL). Intermediate connections Spokane area, Lower Snake area or McNary area-WA Burns area-OR, Raven substation-Northern California
AC-S7	Import 3000 MW from Selkirk–BC Canada via 765 kV AC Single Circuit Tower Line (SCTL). Intermediate connections Spokane area, Lower Snake area or McNary-WA Burns area- OR, Raven Substation Northern California
AC-S8	Import 1500 MW from Selkirk-BC Canada via 500 kV AC Single Circuit Tower Line (SCTL). Intermediate connections Spokane area, Lower Snake area or McNary-WA Burns area- OR, Raven Substation Northern California
DC-S10	Import 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(Proposed by Sea Breeze Corporation)
DC-S11	Import 3000 MW import via +/- 500 kV Bi Pole HVDC line from Selkirk substation -BC to Ravens substation in Northern California. No intermediate terminals
DC-S12	Import 1500 MW import via +/- 500 kV Bi Pole HVDC line from Selkirk substation-BC Canada to Tesla substation in Northern California
HY-S13	Import 1500 MW(0r 3000 MW)[7] from Selkirk-BC Canada and 1500 MW from Pacific Northwest. Hybrid- 500 kV HVAC to Lower Snake or Mid C area WA and 500 kV Bi Pole HVDC (Lower Snake or McNary area) connections to Tesla Substation-Northern California. Intermediate HVAC connections Spokane area, Lower Snake area or McNary area -A.
HY-S14	Import 1500 MW (or 3000 MW)[8] from Selkirk –BC Canada and 1500 MW from Pacific Northwest. Hybrid-500 kV HVAC to Lower Snake or Mid C area-WA, Grizzly area OR and 500 kV Bi Pole HVDC Grizzly area-OR to Tesla substation –Northern California.

Table 2.1: Transmission project alternatives from Canada/Pacific Northwest to Northern California

[7] It is possible this alternative may be rated for 30000 MW import from BC and no renewable resource import from Pacific Northwest.

[8] It is possible this alternative may be rated for 30000 MW import from BC and no renewable resource import from Pacific Northwest.

Alternative	Description
CA 1	500 kV DCTL from the proposed Raven substation to Elverta area (Zeta1) substation with SCTL bypassing Elverta to Tesla Substation. The DCTL portion of the line from Raven Sub will be routed close to Round Mountain-Cottonwood substations. No connection at Round Mountain or Cottonwood substations. This alternative was proposed by TANC[9]
CA 2	500 KV line from the proposed Raven substation to Elverta area(Zeta1) substation and 500 kV line from proposed Raven substation to Tesla substation via Table Mountain substation with connection at Table Mountain. The route will be to east of existing 500 kV line between Table Mountain and Tesla substations.
CA 3	500 kV DCTL from the proposed Raven substation to Elverta area (Zeta1) substation and an SCTL line(by Passing Zeta1) to Tesla substation with connections at Bellota substation The route is in the foot hills of Sierra Mountain range
CA 4	500 kV DCTL lines from the proposed Raven substation to Elverta area (Zeta1) substation with SCTL (by passing Zeta 1) to Tesla substation.
CA 5	500 kV SCTL from the proposed Raven substation to Tesla substation via Table Mountain substation. This connection is for import option AC-S8
CA 6	500 kV SCTL connection between Tesla substation and Elverta area(Zeta 1) substation. This connection for the import option HY-S13 and HY-S14

Table 2.2-Transmission connection alternatives to Northern California transmission grid

[9] In their proposed transmission plan, TANC is exploring alternatives for transmission connection between Northeast California to Elverta area via Round Mountain substation

SECTION 3

Preliminary Cost Estimates

The purpose of developing the preliminary cost estimate is to identify various components that would make up the overall cost from source-to-sink and also to provide the range of cost estimates for various transmission alternatives which will help in identifying a narrow set of alternatives to be analyzed in the technical analysis. The methodology and assumptions used in this study are shown in the Attachments 3.1 and 3.2

The preliminary cost estimate for transmission alternatives was developed based on publicly available unit cost figures for the various transmission components. The preliminary cost estimate[10] contains the Project Facility cost and Network Upgrade cost. Each of these is briefly discussed below.

- Project Facility cost: For each of the alternatives listed in Section 2, Table 2.1 the project cost will include cost components for new lines and substations required to transfer 1500-4500 MW of capacity from the Canada, Pacific Northwest or Eastern Nevada regions to Northern California.

- Network Upgrade Cost. The network upgrade cost includes the cost for

  - Transmission upgrades in BC, the Pacific Northwest, and Nevada for delivery of renewable resources to project line terminations or at intermediate stations along the Project line.
  - Transmission upgrades in the Pacific Northwest and Nevada to mitigate any adverse impact on the existing regional transmission facilities due to interconnection to the project line for regional benefits.
  - Transmission upgrades in Northern California from the Project line termination in Northern California to load centers in the Sacramento or SF Bay area.

The cost to interconnect the potential incremental generation resources either to the project transmission line or to the local area network is not included in the cost estimate at this time. This is because the geographic region for the resource development is large and there is insufficient data on exact location and magnitude of development of these incremental resources.

Unit Cost development

Unit cost figures for the various transmission components were used. These figures were compiled from publicly available data such as the Frontier Line Feasibility Study[11], NTAC[12]

---

[10] The project cost estimates are subject to change based upon subsequent information or analyses and do not include feasibility considerations.

[11] Frontier Line Feasibility Study was completed in June 2007 as a part of Western Regional Transmission Expansion Partnership. The study developed transmission alternatives and cost estimates for west wide transmission expansion plans. The study report can be referenced at http://www.ftloutreach.com/workinggroups/transmissionanalysis.html

report, or from the completed projects in the WECC region such as Path 15 reinforcement in California. Attachment 3.3 shows the unit cost figures in 2006 dollars. The costs for some of the major components are shown in the Table 3.1 below.

Component[13]	**Unit cost in $,000**
500 kV single circuit transmission line in Northwest and Eastern Nevada	2,000/per mile
500 kV double circuit transmission line in Northwest and Eastern Nevada	3,020/per mile
500 kV single circuit transmission line in Northern California	2,150/per mile
500 kV double circuit transmission line in Northern California	3.170/per mile
+/- 500 KV HVDC Line	1,810/per mile
500/230 kV transformer cost(Three single Phase Units)	24,000
Complete 500 kV bay (Breaker And A Half)	3,400/per bay
One segment series compensation	10,000 per segment
Reactive power compensation- 300 MVAR SVC	30,000 per unit
HVDC terminal cost 3000 MW per terminal	500,000

Table 3.1: Summary of unit cost for major transmission components

Project Facility Cost

The project facilities costs are presented in Table 3.2 below. For most inland HVAC alternatives, the northern terminus is at Selkirk Substation in southeast BC, the eastern terminus is at Midpoint Substation in southern Idaho, and the southern terminus is at the proposed Raven Substation in northeast California. For the inland HVDC and Hybrid alternatives the northern terminus is at Selkirk Substation and the southern terminus is at Tesla Substation. If the intermediate station is established for series capacitor switching only the component cost associated with line terminations at the station is included.

For the submarine cable (WCC) alternative, the Project costs include the HVDC transmission cable cost between Allston Substation OR and Martin and Newark Substations in the San Francisco Bay area and the converter station cost at Allston, Martin and Newark Substations.

Network Upgrade Cost

The cost of network upgrades includes the cost (1) to terminate the project facilities to the local area network, (2) to interconnect incremental resources in the region to the project line, and (3) to interconnect load centers. For this study the local area network upgrade cost were developed for the following regions:

---

[12] NTAC- Northwest Transmission Assessment Committee is Planning organization of Northwest Power Pool. In 2006 NTAC released a report entitled CNC final report which discusses the transmission options for increasing the transfer to California from Northwest and Canada. As apart of this report cost estimates were prepared for various options. The CNC report can be referenced at http://www.nwpp.org/ntac/publications.html

[13] For transmission lines the cost shown here is inclusive of ROW assumed in the study which are listed in Appendix 4

a. BC System[14] upgrade cost
b. Pacific Northwest System upgrade cost
c. California Interconnection cost

Each of these will be briefly discussed below.

BC System Upgrade: Based on the L&R Working Group results on potential regions for renewable resource development within British Columbia, BCTC was requested to identify the system upgrades that are likely required to accommodate development of renewable resources within the BC province.

The BC system upgrade cost includes the cost of all upgrades between the BC coast and Selkirk Substation (for the Inland alternative) or Ingledow Substation (for the WCC alternative. Such upgrades are dependent on the level and location resources to be accessed in BC and would include new lines north of Kelly Lake for both alternatives plus reinforcement from Nicola to Ingledow Substation for the WCC alternative[15].

After a preliminary review by BCTC, the committee was informed the system upgrades for the BCTC system would be sensitive to the location of resource development especially to the north and west of Nicola Substation. The L&R Working Group has identified large regions for renewable resource development in BC along the northwest coast (Prince Rupert area) and in the northern region of GM Shrumn (Peace River area).

Based on a preliminary review, BCTC has identified two major 500 kV reinforcements to deliver up to 3000 MW of resources to a delivery point at Selkirk. and Ingledow substation in BC These are a new Skeena-Williston 500 kV line (281 miles) for delivery of 1600 MW of resources along the northwestern coast and a Williston-Kelly Lake 500 kV line (206 miles) for delivery of 1600-2600 MW of resources located along the northwestern coast and in the Peace River area. If only 600 MW of renewable resources is connected to Skeena for delivery to Williston substation then the Skeena-Williston line is probably not required, however the Williston-Kelly Lake line will still be required. In addition to new transmission lines needed for delivery of the resources to Selkirk substation, some station upgrades within the BCTC system may also be necessary. The possible transmission upgrades for the BCTC system are shown in Figures 3.1 and 3.2.

Pacific Northwest Upgrade: For the overland (inland) alternatives, the network upgrade cost includes the 500/230 kV banks at the intermediate stations listed above for receipt of incremental resources or to serve load from the Project line. Such reinforcements will be identified as the locations of these intermediate stations are better defined in the WECC Phase 1 Rating process.

For the undersea cable (WCC) alternative, system upgrades and their associated costs in the Pacific Northwest form Allston to Ingledow substation are anticipated based on

[14] BC system upgrade cost were identified by BCTC_ British Columbia Transmission Company.
[15] The BC system upgrade cost from Nicola to Ingledow was identified in the NTAC study for delivery of 1500 MW of resource from BC to California along the I5 corridor.

previous study work performed by NTAC. These upgrades would be needed to access the renewable resources in BC. Further, the inclusion of such costs provides an equitable source-to-sink comparison of costs between an inland alternative originating at Selkrik Substation in BC and the WCC t. The WCC upgrades are along the I5 corridor in the Pacific Northwest up to Ingledow Substation in BC. These upgrades were identified in the NTAC report as option 3A, and are listed below:

- Ingledow-BC/US Border 500 kV Line
- US/BC Border- Custer 500 kV Line
- Custer-Monroe 500 kV Line
- Monroe-Echo Lake 500 kV Line
- Raver-Paul 500 kV Line
- Paul – Allston Line

Sea Breeze may identify other alternatives for accessing BC renewable resources in their Phase 1 studies.

Northern California Upgrade Cost: Several conceptual plans have been developed for upgrading the Northern California transmission system for those alternatives that terminate at the proposed Raven substation in northeastern California. These plans provide the facilities needed to integrate power received at Raven with the load centers in the Sacramento and San Francisco Bay area. These conceptual plans are described in Section 2, Table 2.2. The cost for these plans were developed using the appropriate unit cost from the Table 3.1 above. In addition to these costs, a $250 million cost was assumed for internal Greater SF Bay area[16] transmission reinforcements such as new 500 KV station and 230 kV reinforcements etc.

A summary of the cost estimates for the project and the network upgrades (BCTC , Pacific Northwest, and California) are shown in Table 3.2. A sample of the worksheet for one of the alternative AC-S1 is shown in the Attachment 3.4

[16] The CAISO has initiated a long term supply study for SF Bay rea. The purpose of this study is to identify transmission alternatives for the supply the internal Greater Bay area load in a reliable manner with a reduced level of . A estimated reinforcement cost for SF Bay area transmission system is included here for the following reasons: 1) It is assumed the renewable resources from Northwest and Canada is likely to displace the existing resources in the Bay area. 2) it also provides for equitable cost comparison between Inland alternative and WCC alternative.

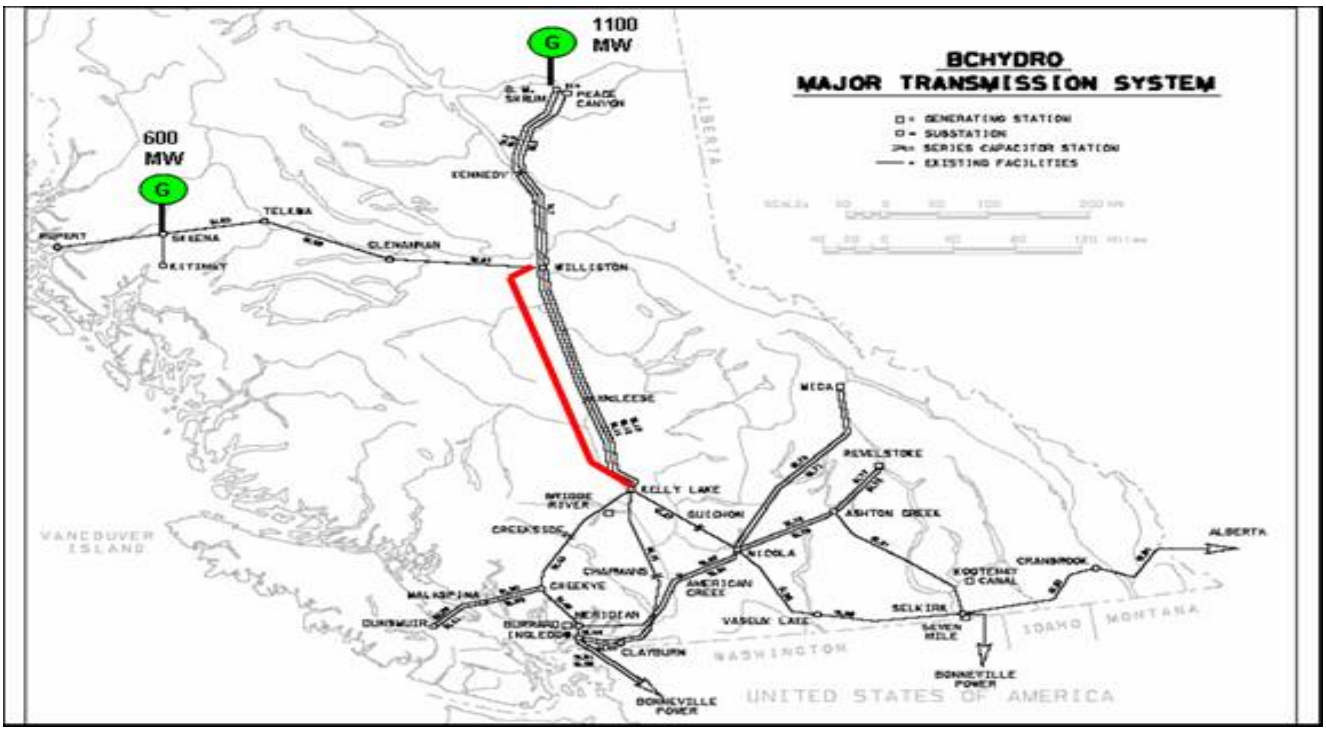


Figure3.1-Potential BCTC system upgrade for incremental resources modeled at Peace River area -1100 MW and Skeena 600 MW.

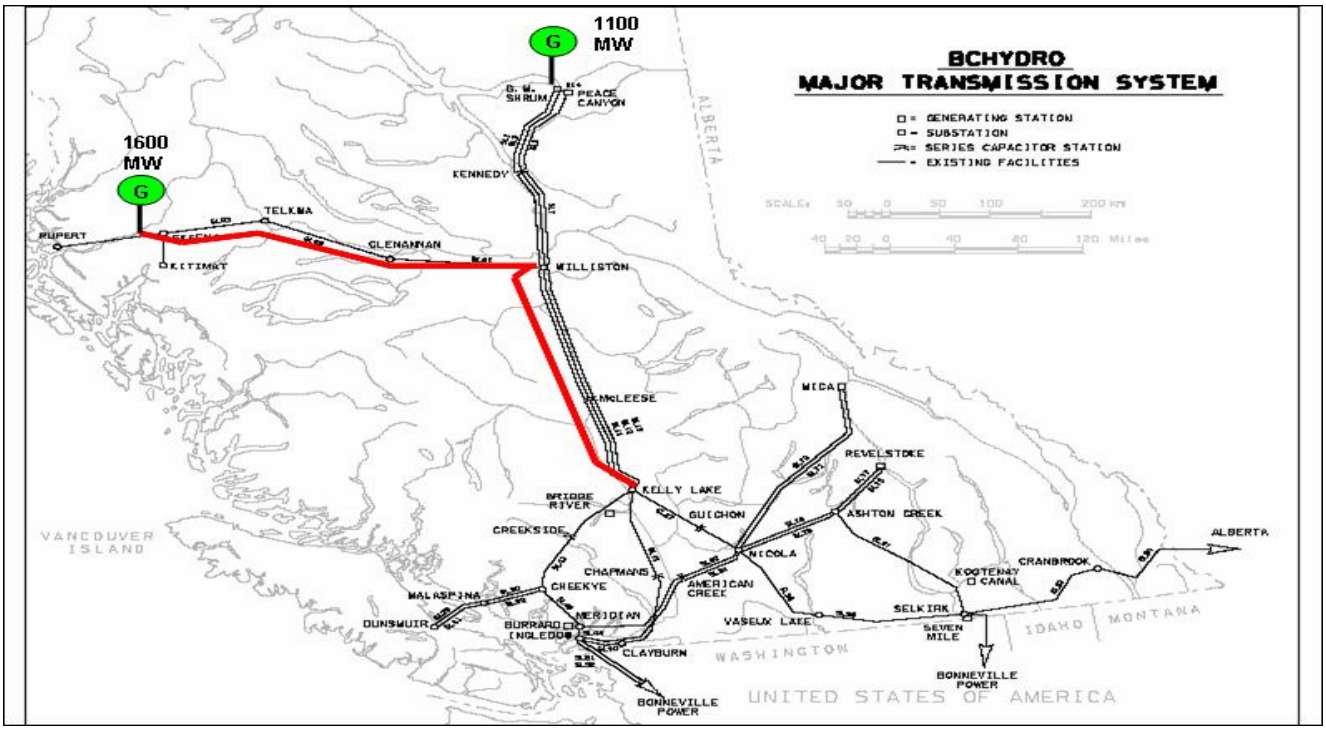


Figure3.2-Potential BCTC system upgrade for incremental resources modeled at Peace River area -1100 MW and Skeena 1600 MW.

All cost in ($, billions)

Scenario	Transmission Option	Import Capability MW	Project Transmission Distance to CA Terminal in Miles (Note 1)	Incremental Resources Located in	Project cost Canada/Pacific Northwest, Nevada to CA Border (Note 2)	BC System Upgrade cost (Note 3)	Pacific Northwest Upgrade cost (Note 4)	California Upgrade cost (Note 5)	Total Cost
AC-S1	500 kV AC DCTL	3000	708	Canada/Pacific Northwest	**2.9**	**1.3**	**0.0**	**1.5**	**5.7**
AC-S2	500 KV AC DCTL	3000	708	Canada/Pacific Northwest	**2.7**	**1.2**	**0.1**	**1.5**	**5.5**
AC-S3	500 KV	3000	1180	Canada/Eastern Nevada	**2.8**	**2.2**	**0.1**	**1.5**	**5.6**
AC-S4	765 and 500 kV AC	3000	1230	Canada/Eastern Nevada	**4.2**	**2.2**	**0.3**	**1.5**	**7.2**
AC-S5	500 kV DCTL	3000	584	Pacific Northwest	**2.1**	**0.0**	**0.1**	**1.5**	**3.8**
AC-S6	Two 500 kV AC SCTL	3000	708	Canada	**3.2**	**1.3**	**0.0**	**1.5**	**6.0**
AC-S7	765 kV AC	3000	708	Canada	**2.5**	**1.2**	**0.2**	**1.5**	**6.4**
AC-S8	Two 500 kV AC SCTL	1500	708	Canada	**2.1**	**1.2**	**0.0**	**1.3**	**4.6**
DC-S10 (Note 6)	500 kV HVDC (submarine Cable)	1600	650	Canada	**2.1**	**1.5**	**0.7**	**0.0**	**4.4**
DC-S11	500 kV HVDC (inland OH)	3000	708	Canada	**2.7**	**1.3**	**0.0**	**1.5**	**5.1**
DC-S12	500 kV HVDC (inland OH)	1500	956	Canada	**2.7**	**1.2**	**0.0**	**0.3**	**4.1**
HY-S13	500 kV AC and +/-500 kV HVDC	3000	956	Canada/Pacific Northwest	**2.8**	**1.2**	**0.1**	**0.6**	**4.8**
HY-S14	500 kV AC and +/-500 kV HVDC	30000	944	Canada/Pacific Northwest	**3.2**	**1.2**	**0.1**	**0.6**	**5.2**

Table 3.2 -Canada/Pacific Northwest-Northern California Transmission Project Review: Transmission Line Project cost, and Local Area upgrade cost

Disclaimers:
The cost estimates in the tables in this section are based on unit cost and not on engineering review and are subject to change based on subsequent information, analyses and feasibility consideration.. The cost estimates are in 2006 dollar value and do not include escalation.

Notes

1. For all scenarios evaluated transmission distance is length of bulk power line for delivery from Canada (Selkirk SUB)/ Pacific Northwest to California Border sub 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 of the bulk power transmission line from Canada-Selkirk or (Allston for scenario DC-S10) to the Northern California border 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. For the analysis it is assumed the BCTC reinforcement cost will be treated as a part of BCTC network access charge. Via BCTC- OATT.

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. It does not include any system impact cost associated with interconnection with the project line. Upon completion of WECC Phase 1 rating studies establishing a firm plan of service, these costs may change and will be revised accordingly.

5. Based on the timing of this project line, only a portion of the California connection cost identified (approximately ($1.5 billion) for deliver 3000 or 1500 MW to the load centers in the SF Bay area is used here. 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)

Section 4

Preliminary Technical Study

The purpose of this preliminary technical study is to demonstrate the feasibility of the project in accordance with NERC/WECC reliability standards. This section summarizes the results of preliminary power flow studies that were conducted for the selected alternatives.

Study Base Case and Contingency Analysis

The GE PSLF Version 16.0_11 Load Flow Program was used to perform the power flow studies. PG&E's governor power flow routine was used to perform post transient power flow contingency analysis. Although the study plan calls for the evaluation of both north to south and south to north flow conditions, the study focused on north to south flow conditions. South to north power flow, transient stability, and more detailed reactive margin studies will be completed as part of the WECC Phase 1 rating studies.

The starting power flow base case used in this analysis is the WECC 2016 Heavy Summer Peak base case (16HS1A1). The generation, load and area interchange for some of the regions from Canada to Northern California are shown in Table 4.1 below. From this case a Benchmark (or pre-project) case and Project cases for the selected alternatives were developed.

Area	Generation Dispatch MW	Load MW	Area Interchange MW
Alberta	10481	9907	200
BC-Hydro	10130	7561	2010
Pacific Northwest	29540	23605	4626
PG&E	27591	28234	-1670
Southern California Edison	17950	23978	-6465

Table 4.1 Generation, Load and Area Interchange for selected areas

Benchmark Case: The WECC 2016 HS1A1 base case featured high hydro in Canada and the Pacific Northwest, median hydro in California, and heavy north-to-south interchange flows on major west coast paths and the PDCI. Path flows were modified to represent a corner point on the North of John Day vs. COI + NW/Sierra or PDCI Flow (Summer 2006 N-S Nomogram) from the NOPSG 2006 summer OTC study prepared by BPA. Path 3 (Northwest - Canada) flow was increased to its Path Rating of 3150 MW north-to-south. This modified 2016 base case became the benchmark summer peak base case for the technical studies. Major path flows for the Benchmark Case are listed in Table 4.2 below:

#	Path Name	Path Rating	2016 HS1A	Benchmark Case
3	Northwest - Canada	3150 MW (n2s)	2301 MW(n2s)	3150 MW (n2s)
26	Northern – Southern Calif.	4000 MW (n2s)	2185 MW (n2s)	4000 MW (n2s)
65	PDCI	3100 MW (n2s)	2980 MW (n2s)	2850 MW (n2s)
66	COI	4800 MW (n2s)	3776 MW (n2s)	4400 MW (n2s)
73	North of John Day	8400 MW (n2s)	7949 MW (n2s)	7800 MW (n2s)
75	Midpoint – Summer Lake	1500 MW (e2w)	85 MW (w2e)	400 MW (e2w)
76	Alturas Project	300 MW (n2s)	263 MW (n2s)	300 MW (n2s)

Table 4.2 Major Path Flows for Benchmark Case

Other projects such as the BPA-West of McNary Project, PGE- Southern Crossing Project, PacifiCorps-Gateway Projects were proposed while the Canada-Northern California project was in regional planning process but were not considered in this analysis.

PG&E's governor power flow routine was used to perform post transient power flow contingency analysis, and to demonstrate that system performance complies with the reliability criteria specified in the ***Reliability Criteria Part 1 - NERC/WECC Planning Standards*** and ***WECC Voltage Stability Criteria***. PG&E's governor power flow routine makes the following assumptions:

- All static var devices (svd's) are blocked from adjusting during the post transient period
- Load tap changing transformers (LTC's) are allowed to adjust during the post transient period
- Phase shifting transformers are blocked from adjusting during the post transient period
- AGC is assumed not to have adjusted the dispatch during the post transient period
- All governors with Base Load Flag of "1" in the base case are assumed not to provide MW response to system load/resource imbalances during the post transient period
- All governors with Base Load Flag of "0" in the base case are assumed to respond to system load/resource imbalances with a 5% droop characteristic proportional to their unloaded capability.

Contingency analysis of the selected project base cases was performed for the following contingencies:

1.	Selkirk Area – Spokane Area 500 kV N-1
2.	McNary Area – Grizzly Area 500 kV N-2
3.	McNary Area – Grizzly Area 500 kV N-1
4.	Grizzly Area – Tesla DC Bipole Outage
5.	PDCI Bipole Outage
6.	Palo Verde Double-Unit Outage
7.	San Onofre Double-Unit Outage
8.	Diablo Canyon Double-Unit Outage
9.	Malin – Round Mt N-2
10.	Round Mt – Table Mt N-2
11.	Table Mt South N-2

Table 4.3 Major Contingencies studied

Project Case Development: The major elements considered in development of the project cases are:

- Transmission Alternatives considered for the study
- Incremental Resource Addition
- Generation Retirements- Identify generation units which will be retired to achieve desired flow on the proposed alternative
- Transmission System Model- Based on alternative selected

Further discussion on these can be found in Attachment 4.1

Transmission alternatives for technical analysis: Some of the alternatives listed in Table 2.2 were chosen for analysis. PG&E developed base cases and analyzed transmission system performance for the transmission line interconnection to Selkirk Substation (BC) Canada. TANC developed base cases and analyzed the transmission system performance for the transmission line alternative to Midpoint Substation-Idaho. Sea Breeze Corporation analyzed the WCC alternative.

From the alternatives listed in Table 2.1 and 2.2, PG&E developed base cases for following alternatives:

AC-S1 with CA-2 with no network connection in Pacific Northwest: 500 kV HVAC from Selkirk BC to Tesla and Elverta substations in northern California with a north-to-south transfer capability of 3000 MW from Canada to northern California

AC S2 with CA-2 with network connection: A 500 kV HVAC from Selkirk BC to Tesla and Elverta substation in northern California with network connection in the Lower Snake area (Lower Monumental substation)-WA and in the Burns area (Burns substation)-OR with a north-to-south transfer capability of 3000 MWfrom either Canada or the Pacific Northwest to northern California

HY-S14-Hybrid: A combination of HVAC and HVDC facilities. 500 kV HVAC from Selkirk-BC to Grizzly area-OR and 500 kV Bi-pole HVDC from Grizzly area-OR to Tesla substation–northern California with intermediate connections in the Spokane area, the Lower Snake area or the McNary area in WA with a north-to-south transfer capability of 3000 MW from either Canada or the Pacific Northwest to northern California

Project Base Case and Analysis

AC-S1 with CA-2 with no network connection in Pacific Northwest: This alternative models a 950 mile, 500 kV HVAC double circuit tower line from Selkirk Substation in BC to Tesla and Elverta substations in Northern California with no network interconnection in the Pacific Northwest. 3000 MW of generation was added in BC-Canada and 3000 MW of generation was taken off-line in the San Francisco Bay area. The area interchange and series compensation on the project line were adjusted to provide a 3000 MW transfer from BC- Northern California. The table below shows the major path flows for this interconnection.

Path #	Path Name	Path Rating	2016 HS1A	Benchmark Case	Project Case AC S1
3	**Northwest – Canada**	3150 MW (n2s)	2302 MW (n2s)	3150 MW (n2s)	3150 MW (n2s)
26	**Northern – Southern Calif.**	4000 MW (n2s)	2185 MW (n2s)	4000 MW (n2s)	4000 MW (n2s)
65	**PDCI**	3100 MW (n2s)	2980 MW (n2s)	2850 MW (n2s)	2850 MW (n2s)
66	**COI**	4800 MW (n2s)	3776 MW (n2s)	4400 MW (n2s)	4400 MW (n2s)
73	**North of John Day**	8400 MW (n2s)	7949 MW (n2s)	7800 MW (n2s)	7808 MW (n2s)
75	**Midpoint – Summer Lake**	1500 MW (e2w)	85 MW (w2e)	236 MW (w2e)	247 MW (w2e)
76	**Alturas Project**	300 MW (n2s)	263 MW (n2s)	264 MW (n2s)	259 MW (n2s)
666	**BC – California**	3000 MW (n2s)	N/A	N/A	3000 MW (n2s)

Table 4.3: AC-S1 alternative desired path flows with no interconnection in Pacific Northwest

The analysis showed the case required a large amount of reactive compensation (1600 MVAR) to achieve a desired flow of 3000 MW on the project facility while maintaining acceptable base case voltage. Also, for some of the critical contingencies listed in the table above, such as the Palo Verde double unit outage or PDCI outage, additional reactive compensation of 2100 MVAR was required to meet the post transient voltage performance. With no network connection on this long AC transmission line, the system performance was shown to be extremely sensitive to minor changes in the shunt compensation levels along this line and the cases were very difficult to solve. Since this alternative does not have network interconnections in the Pacific Northwest, it does not meet the objectives of providing regional transmission benefit or of providing opportunity for new resources to interconnect to the project line in the Pacific Northwest. The technical analysis concluded this is not a feasible alternative.

AC S2 with CA-2 with network connection: This alternative models a 950 mile, 500 kV HVAC double circuit tower line from Selkirk Substation in BC Canada to Tesla and Elverta Substations in Northern California with network connections in the Lower Snake area (Lower Monumental substation)-WA and in the Burns area (Burns substation)-OR. 1500 MW of generation was added in BC-Canada and 1500 MW of generation was added in the Pacific Northwest, with 3000 MW of generation removed from service in the San Francisco Bay area.

To achieve the desired flow on the project transmission facility, series compensation levels on the existing AC lines between John Day and Table Mountain substations had to be significantly reduced. This will likely have some negative impacts on the OTC[17] of the existing AC path. Table 4.4 and 4.5 below shows the path flows and the changes to reactive compensation levels on the existing AC lines required to achieve the desired flow on the project transmission line.

[17] OTC- Operational Transfer Capability

Path #	Path Name	Path Rating	2016 HS1A	Benchmark Case	Project Case with LM (Mid C Area) Connection
3	Northwest – Canada	3150 MW (n2s)	2302 MW (n2s)	3150 MW (n2s)	3153 MW (n2s)
26	Northern – Southern California	4000 MW (n2s)	2185 MW (n2s)	4000 MW (n2s)	4000 MW (n2s)
65	PDCI	3100 MW (n2s)	2980 MW (n2s)	2850 MW (n2s)	2850 MW (n2s)
66	COI	4800 MW (n2s)	3776 MW (n2s)	4400 MW (n2s)	4521 MW (n2s)
73	North of John Day	8400 MW (n2s)	7949 MW (n2s)	7800 MW (n2s)	7839 MW (n2s)
75	Midpoint – Summer Lake	1500 MW (e2w)	85 MW (w2e)	236 MW (w2e)	237 MW (w2e)
76	Alturas Project	300 MW (n2s)	263 MW (n2s)	264 MW (n2s)	265 MW (n2s)
666	BC – California (North)	3000 MW (n2s)	N/A	N/A	2998 MW (n2s)

Table 4.4: AC-S2 alternative desired path flows with network connection in the Pacific Northwest

Transmission Facility	Benchmark Case	Burns Connection	Burns & Lower Monumental Connection
MALIN – ROUND MT #1&2	62%	0%	0%
CAPTJACK - OLINDA	62%	62%	56%
JOHN DAY - CAPTJACK	54%	0%	54%
JOHN DAY - MALIN	53%	33%	53%
GRIZZLY – MALIN #1	79%	79%	56%
SUMMER L – BURNS - MELBA	49%	0%	0%

Table 4.4: Changes in series compensation levels for the project case with network interconnection in Pacific Northwest

One option considered for mitigating[18] the adverse impact of AC interconnection is to establish additional ties between the Project line and existing PACI facilities, and changing series compensation on the existing PACI in order to achieve balanced flow along the existing PACI and Project line facility. The cost estimates for AC alternatives includes the cost of facility upgrades required to achieve the desired system performance for the AC alternative.

Based on the preliminary technical analysis of both AC alternatives discussed above, the system performances under various conditions are either infeasible or very costly to meet. Thus a hybrid option which is a combination of HVAC and HVDC was considered for development.

[18] Mitigation plan was considered for cost development and no technical studies were carried out. NTAC studies completed in 2005 considered a similar option but for 1500 MW tie line between Pacific Northwest and Northern California.

HY-S14-Hybrid: This alternative models a 950 mile transmission facility consisting of a 500 kV HVAC line from Selkirk-BC to Grizzly area-OR, and a 500 kV Bi Pole HVDC line from Grizzly area-OR to Tesla Substation-Northern California with intermediate connections in the Spokane area, the Lower Snake area or the McNary area in WA and a 3000 MW transfer capability between Grizzly area and Tesla Substation

The area interchanges, series compensation on the project line, and DC converter schedules were adjusted to provide a 3000 MW transfer from the Grizzly area to Tesla Substation. Table 4.5 below shows the major path flows for this interconnection.

Path #	**Path Name**	**Path Rating**	**2016 HS1A**	**Benchmark Case**	**AC/DC Hybrid Case**
3	Northwest – Canada	3150 MW (n2s)	2302 MW (n2s)	3150 MW (n2s)	3096 MW (n2s)
26	Northern – Southern Calif.	4000 MW (n2s)	2185 MW (n2s)	4000 MW (n2s)	4002 MW (n2s)
65	PDCI	3100 MW (n2s)	2980 MW (n2s)	2850 MW (n2s)	2850 MW (n2s)
66	COI	4800 MW (n2s)	3776 MW (n2s)	4400 MW (n2s)	4364 MW (n2s)
73	North of John Day	8400 MW (n2s)	7949 MW (n2s)	7800 MW (n2s)	8528 MW (n2s)
75	Midpoint – Summer Lake	1500 MW (e2w)	85 MW (w2e)	236 MW (w2e)	304 MW (w2e)
76	Alturas Project	300 MW (n2s)	263 MW (n2s)	264 MW (n2s)	259 MW (n2s)
666	BC – California (North)	3000 MW (n2s)	N/A	N/A	1556 MW (n2s)
667	Grizzly Area – Tesla HVDC	3000 MW (n2s)	N/A	N/A	3000 MW (n2s)

Table 4.5: Hybrid Alternative desired path flows with network connection in the Pacific Northwest

It was found that the most critical outage for the system with the 3000 MW AC/DC hybrid project in service was the Palo Verde Double-Unit Outage. Interconnection points with the 500 kV transmission system in the Pacific Northwest must be chosen such that reactive margin is adequate following the Palo Verde Double-Unit Outage. The hybrid option must utilize optimal levels of series compensation on the proposed new 500 kV AC lines in order to ensure adequate voltage stability performance. The AC/DC hybrid project was designed with enough reactive support to maintain pre-contingency voltages in the Hybrid Base Case at Benchmark Base Case levels, and all voltage stability and reactive margin reliability requirements were met for all contingencies studied. It was noted that the Palo Verde Double-Unit Outage did not require any additional RAS (Remedial Action Scheme) to that which is presently utilized for the existing system.

The bipole outage of the proposed HVDC line between the Grizzly Area and Tesla required tripping of 3000 MW of incremental generation in Canada and the Pacific Northwest in order to meet the reliability criteria.

The Double-Line Outage of the proposed McNary Area – Grizzly Area 500 kV lines required 1500 MW of incremental generation dropping in the Pacific Northwest.

The Single-Line Outage of the proposed Selkirk Area – Spokane Area 500 kV line required tripping approximately 800 MW of incremental generation in Canada and inserting a 200 MVAR shunt reactor at the Spokane Area 500 kV bus.

The post transient power flow results are summarized in the table below:

	Contingency	Remedial Actions Required	Post Transient Voltage Criteria	Emergency Overloads
1.	Selkirk Area – Spokane Area 500 kV N-1	800 MW incremental generation tripping in Canada	All post transient bus voltage dips < 5%	No additional emergency overloads
2.	McNary Area – Grizzly Area 500 kV N-2	1500 MW incremental generation tripping in Pacific Northwest	All post transient bus voltage dips < 10%	No additional emergency overloads
3.	McNary Area – Grizzly Area 500 kV N-1	No RAS required	All post transient bus voltage dips < 5%	No additional emergency overloads
4.	Grizzly Area – Tesla DC Bipole Outage	3000 MW incremental generation tripping in Pacific Northwest and Canada	All post transient bus voltage dips < 5%	No additional emergency overloads
5.	PDCI Bipole Outage	Existing RAS	All post transient bus voltage dips < 5%	No additional emergency overloads
6.	Palo Verde Double-Unit Outage	Existing RAS	Post transient power flow case converges	No additional emergency overloads
7.	San Onofre Double-Unit Outage	Existing RAS	All post transient bus voltage dips < 10 %	No additional emergency overloads
8.	Diablo Canyon Double-Unit Outage	Existing RAS	All post transient bus voltage dips < 10 %	No additional emergency overloads
9.	Malin – Round Mt N-2	Existing RAS	All post transient bus voltage dips < 10 %	No additional emergency overloads
10.	Round Mt – Table Mt N-2	Existing RAS	All post transient bus voltage dips < 10 %	No additional emergency overloads
11.	Table Mt South N-2	Existing RAS	All post transient bus voltage dips < 10 %	No additional emergency overloads

Table 4.6: Hybrid alternative - post transient power flow study result summary

In addition to determining the performance of the proposed hybrid AC/DC project with the applicable reliability criteria, some additional reactive margin analysis was performed in order to gain insight on the performance of the project relative to the existing system. QV curves for the Benchmark Case and AC/DC Hybrid Case were plotted for the Palo Verde Double-Unit Outage and PDCI Bipole Outage post transient base cases. QV curves for the Grizzly, Malin, Round Mt, and Table Mt 500 kV buses following the Palo Verde outage are shown in Figure 4.1 below:

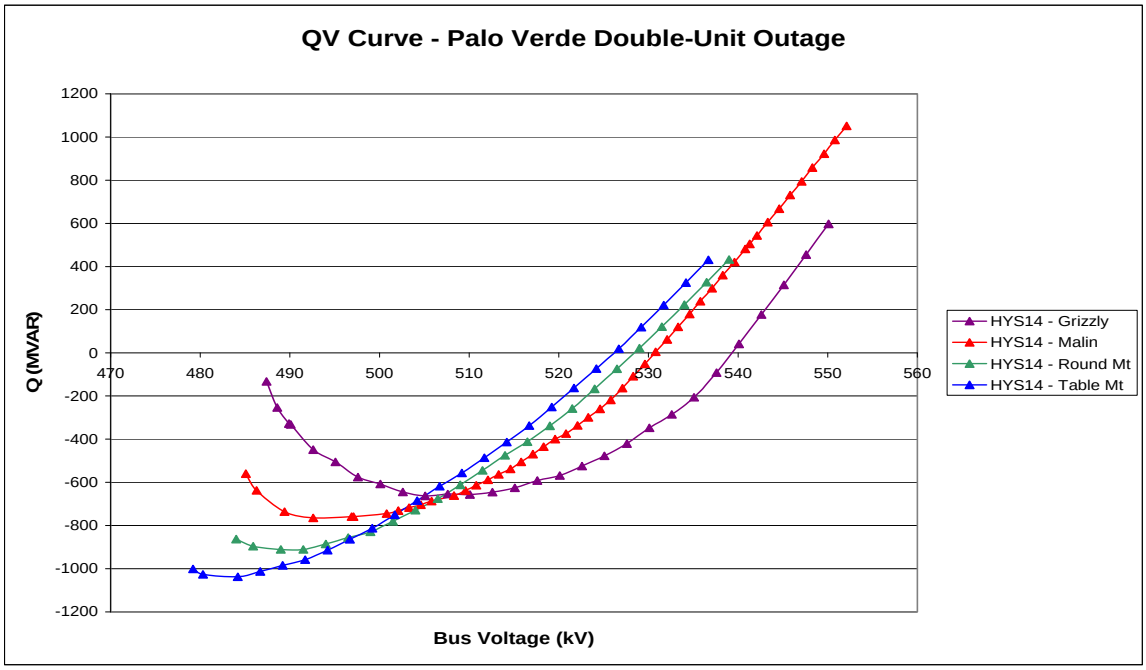


Figure 4.1: QV curve for Hybrid case- Palo Verde Double Unit Outage

Note that the only applicable voltage stability reliability criterion for the Palo Verde Double-Unit Outage is that the base case converges for the post transient period. The following discussion of the post transient performance of the system following the Palo Verde Double Unit outage is included for informational purposes, and to demonstrate the post transient performance of the Hybrid project relative to the Benchmark Case. The VIPI (Voltage Instability Proximity Indicator) at all of the buses in Figure 4.5 is greater than the PG&E post transient voltage collapse criteria of 400 MVAR. All 500 kV post transient bus voltages are greater than 480 kV, and there is greater than 15 kV difference between the post transient steady state operating point and the nose of the QV curve for each of the buses. The worst case of these buses was the Grizzly 500 kV bus with a VIPI (Voltage Instability Proximity Indicator) of 663 MVAR. The VIPI at the Grizzly 500 kV bus in the Benchmark case is 600 MVAR. A comparison of the QV curves at the Grizzly 500 kV bus between the Hybrid and Benchmark cases is shown in Figure 4.2 below:

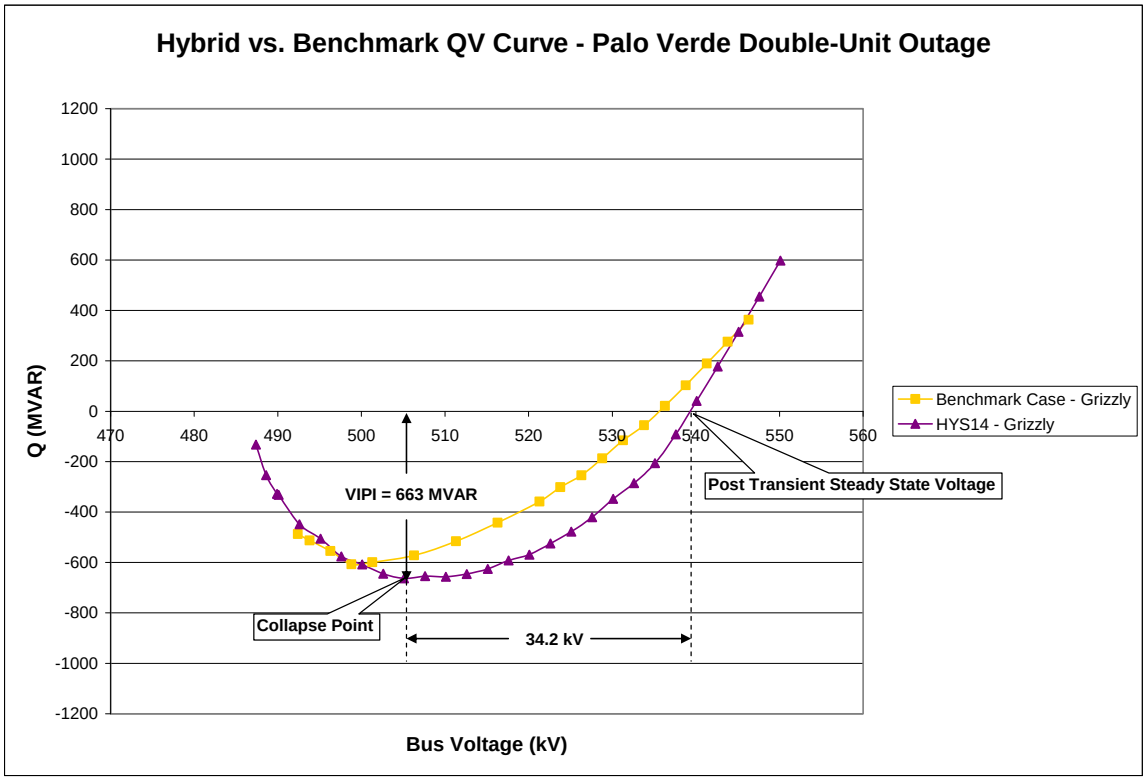


Figure 4.2: QV curve for Hybrid case- Palo Verde Double Unit Outage Comparison with Benchmark case

QV curves for the Grizzly, Malin, Round Mt, and Table Mt 500 kV buses following the PDCI outage are shown in Figure 4.3 below:

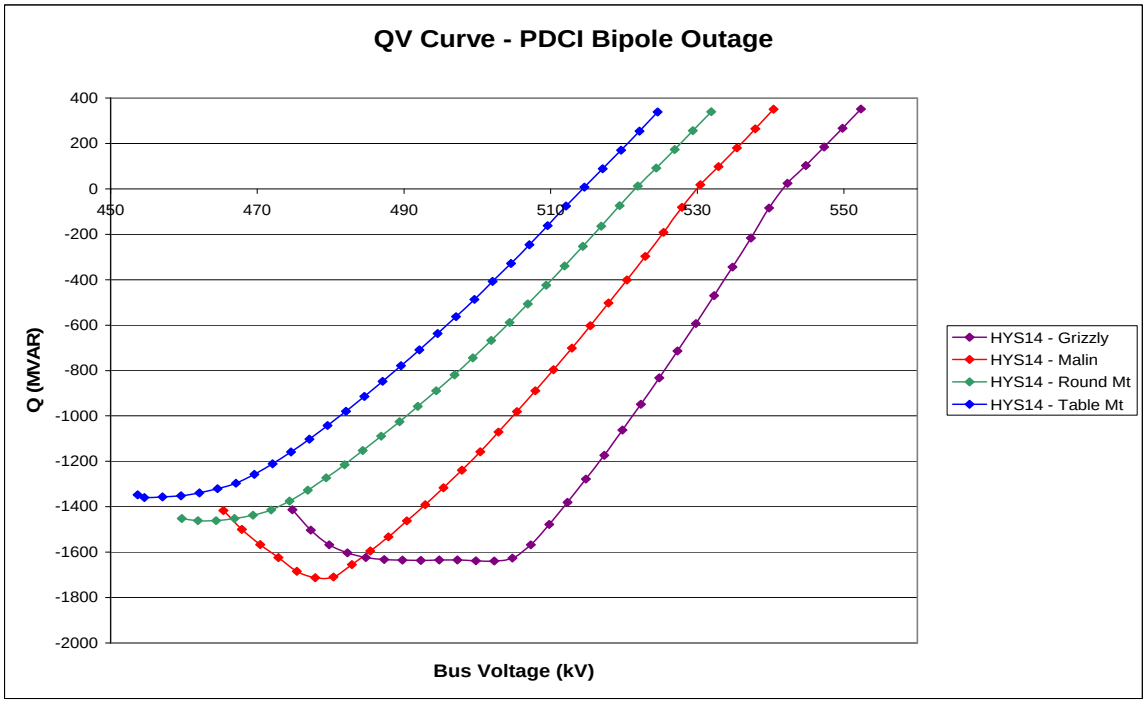


Figure 4.3: QV curve for Hybrid case- PDCI Bipole Outage

The worst case 500 kV bus, Table Mt, still had substantial reactive margin following the PDCI Bipole Outage.

The QV curve for the worst case Table Mt 500 kV bus was plotted against the Benchmark Case Table Mt 500 kV bus QV curve for comparison in Figure 4.4 below:

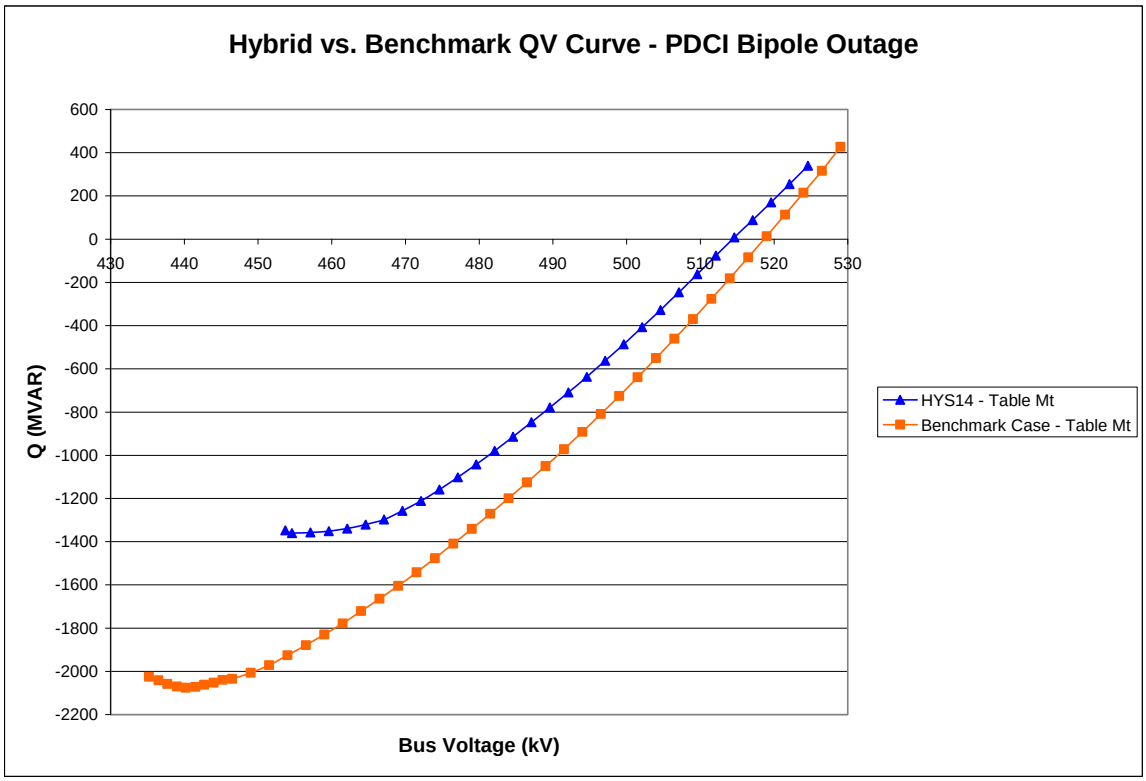


Figure 4.4: QV curve for Hybrid case- PDCI Bipole Outage-Table Mountain Substation

The Benchmark Case had greater reactive margin than the AC/DC Hybrid Case for all 500 kV buses following the PDCI Bipole Outage.

Other Alternative Studied

In addition to the alternative studied by PG&E Company described above, other alternatives were evaluated by TANC and Sea Breeze Corporation and are discussed below.

AC S3: This alternative is a 500 kV AC Single Circuit Tower Line (SCTL) from Selkirk Substation (BC, Canada) and 500 kV AC Single Circuit Tower Line (SCTL) from Midpoint Substation (Idaho)with intermediate connections Spokane area, Lower Snake area or McNary area-WA, Burns area- OR, Valmy area-NV and Raven substation-Northern California. 1500 MW of generation was added in BC-Canada and 1500 MW of generation was added in Eastern Nevada and Idaho and 3000 MW of generation retired in the San Francisco Bay area. TANC developed this alternative and the findings are discussed below.

The analysis by TANC showed it was able to make scheduled power flow on the segment of the Project line from Midpoint Substation to Raven Substation, but only with substantial compensation on the Project line and use of a Phase Shifting Transformer. .In this analysis other transmission projects in Idaho, Pacific Northwest, and Nevada now in WECC regional planning review were not modeled. TANC will continue to study this alternative to establish its full potential by modeling the transmission project development in eastern Nevada and Idaho.

West Coast cable Alternative-DC-S10: This alternative is for an undersea Bipole HVDC cable connection between Allston Substation –Oregon and Newark and Martin Substations in San Francisco Bay area with HVDC terminals at Allston, Newark and Marin Substations. This alternative has Import capability of 1600 MW. Sea Breeze Corporation sponsored this alternative and has initiated WECC Phase 1 Rating studies for this alternative. Please contact Sea Breeze Corporation for the details of their analysis.

Section 5

Stakeholder Comments and TAC Response

Comments were received from the TAC members on the draft report. Some of the comments were editorial in nature and the suggested changes have been incorporated in this report. Other comments noted the need for additional clarification on some aspects of the analysis and the presentation of the results. This section addresses those comments and the associated response.

Comments received from Robert Jenkins- PG&E Company.

1. **Comment:** I understood that one of the major findings of this effort is that the pure AC alternatives have technical issues. Therefore, should they even be included in the cost comparison table?

   Response: The technical studies showed an AC alternative with connections from Selkirk Substation to the Raven or Tesla substations but without network interconnections in the Pacific Northwest is infeasible. The analysis shows that the AC alterative with network connections in the Pacific Northwest has some adverse negative impact of the performance of existing PACI. However the adverse impact may be mitigated with connection of the Project line with additional interconnection s along the existing PACI and changing out the level of series compensation on the PACI south of Grizzly Substation. The study addresses these mitigation by adding a cost to AC alternative to interconnect to stations along the existing PACI and the cost for new series compensation south of Grizzly Substation .

2. **Comment:** This table (in the summary) is misleading. Needs to include transmission costs from the generator busbar to the load, including all the segments from the table on page 23.

   Response: The table in the summary has been modified to include the preliminary cost estimate for all alternatives to reflect source to sink cost.

3. **Comment:** Round Mountain Substation -- This is something new. Why is this potential third terminal being considered?

   Response: Round Mountain substation may be a potential third HVDC terminal to facilitate transfers of renewable resources that may develop in Northern California and Nevada to the load centers in the Sacramento and San Francisco Bay area.

4. **Comments**: Shouldn't this begin with how the L&R Committee info was used to arrive at the transmission options?

   Response: The write-up was modified to include reference to Loads and Resources Work Group.

5. **Comments:** The Midpoint leg needs to be addressed separately since it has not had the same level of analysis and no cost info is presented. Otherwise the reader is left wondering what happened to it.

   Response: The transmission alternatives with AC interconnection to Midpoint Substation - Idaho via eastern Nevada was proposed by TANC. For this report TAC evaluated the cost of the transmission facilities to Idaho. TANC will conduct the technical evaluation for this alternative.

6. **Comment:** Possibly note that AC lines need a connection every ~250 miles.

   Response: An assumption is made for the AC line that will require connection approximately every 175-250 miles

7. **Comment:** Describe – or better yet, add discussion in the beginning on the input from the L&R Committee

   Response: Incorporated reference to L&R Work Group work.

8. **Comment:** I do not recall much discussion on this one. Round Mountain seems out-of-the-way from Raven.

   Response: please see the response 3 above and also in their proposed transmission plan, TANC is exploring alternatives for transmission connection between Northeast California to Elverta area via Round Mountain substation.

9. **Comment:** While breaking the costs down in this fashion may have some value in future cost allocation discussions, it can be confusing or even misleading for the reader. They see these costs, which are the ones most prominently displayed, and incorrect believe that these are all the transmission costs.

   Response: We have eliminated the table showing only the Project line cost. The revised Table 3.2 shows the cost components as Project line, BC System upgrade, Pacific Northwest upgrade and California upgrade. The summation of the cost component is the total cost from source to sink.

10. **Comment**: I do not believe that this is sufficient. Really need to look all the way up to Nicola. Otherwise there is a hole in the plan as the common internal BC upgrades stop at Kelly Lake.

    Response: Based on the location and magnitude resource development within BC System, the BCTC's preliminary review did not identify system upgrades south of Kelly Lake. However based on NTAC studies for 1500 MW import to SF Bay area from Canada and Pacific Northwest, TAC has included the cost of Ingledow to Nicola section upgrade in the BCTC network upgrade cost.

11. **Comment:** Does this assume that the Paul-Troutdale takes care of the lat leg down to the Columbia River? I would expect that additional work may be needed on this segment to

accommodate both the drivers of the Paul-Troutdale expansion and this incremental flow. From BC to Allston

Response: These I5 upgrades are intended to reinforce sections of Pacific Northwest from the BC border and do not address the need for Paul-Troutdale line. Additional Studies would have to identify the need. Mike Kreipe of BPA will check the cost estimate for network upgrade in Pacific Northwest to accommodate 1600 MW delivery to Allston Substation.

12. **Comment:** I am not clear why this costs are being included. The objective of the project is to bring renewable generation to CA. Is it shown anywhere that this cannot be done without also upgrading the lines into the Bay Area. In order to make a fair comparison to the submarine cable, you may wish to show this $500,000,000 as a benefit for the submarine. However, as presented, it looks like we cannot build the line to BC without solving the Bay Area issues as well.

Response: It is assumed in the studies the resources from BC and Pacific Northwest may displace the generation in the SF Bay area, and hence the need to get the renewable resources to the bay area will require SF bay area reinforcements. However if the resources can be absorbed elsewhere in Northern California then with a different set of assumption on where the generation is re-dispatched within Northern California, the reinforcement cost can change.

13. **Comment:** Add a TOTAL column on the right- Table 3.4

Response: The table is now table 3.2 and shows the total of cost components.

14. **Comments:** This is mis-leading as these make it look like the 3000 MW and 1500 MW options cost the same. *This refers to the Project line cost for DC –S11 and DC-S12.*

Response: The Project line cost for Alternative DC-S11 is for the HVDC line termination at the Raven substation with AC interconnection or upgrades cost from Raven to Tesla Substations. The AC reinforcement or upgrade cost south of Raven Substation including the SF Bay area upgrade cost is part of California upgrade cost and not the Project line cost. Whereas the alternative DC-S12 as Project line HVDC termination at Tesla Substation and only the cost of SF bay Area is included for California upgrade cost.

Comment received from Mike Kriepe - BPA

15. **Comment**: Reinforcement of the I5 corridor needed for the WCC (1600 MW DC from Allston to San Francisco) option is missing some key transmission. In order to gain 1600 MW of capacity along the I5 corridor from north (BCH) to south (Allston), the following transmission is needed.

Ingledow-Custer 9.1 miles (included in report) Do not know what the cost estimate for this piece is (most of the line is in BC)

Custer-Monroe 86 miles (included in report) Cost will be about $130 M.

Monroe-Echo Lake 30 miles. Not included in report. About two years ago we developed two alternatives for this project (G-8) and both were estimated to cost about $240M. This is a very difficult area to build a new line. It also has to be on a seperate ROW to gain the incremental 1600 capacity. Land cost will be very expensive because this land is being sold for home sites. This is total project cost which includes everything.

Echo Lake-Raver. 12 miles. Not included in report. There is only one 500 line between Echo Lake and Raver. A second line is required to gain 1600 MW of capacity. The line is only 12 miles long and BPA has in place about 3 miles of it. The existing line here was added in 2003 at a cost of $45M (9 miles). This is a total project cost including everything (in 2003 dollars). This line goes through the Seattle watershed and we had extreme problems with gaining the ROW. A second ROW (needs to have seperation) may not be possible to get permission. The alternate transmission routing could be more expensive. Another option would be to bypass Echo Lake and instead build a Monroe-Raver line. I don't have a cost estimate for this option.

Raver-Paul 69 miles. (included in report) Cost will be about $110 M.

Paul-Allston 48 miles. Not included in report. The third line between Paul and Allston is needed to gain 1600 MW capacity. Cost will be about $71M.

So the total cost of transmission from Custer to Allston (I left out the Ingledow-Custer cost because I do not know what you assumed) is about $600 M. This includes materials and construction. It does not include substation terminals, land or overhead except where noted. Overhead would add at least $100 to 150 M. Terminal cost would add about $20 M. I have no estimate of land cost.

Concerning the DC option at Grizzly, with two 3000 MW DC terminals relatively close together (Celilo is about 100 miles from Grizzly) some thought should given to common mode contingencies that could compromise both of the terminals at the same time. If both DC terminals were lost, the COI would not have a chance of maintaining synchronism and it would result in a major load shedding event in Cal.

I hope this helps with keeping the cost realistic.

Response: Updated the cost for I5 reinforcements in the Pacific Northwest for the West Coast Cable alternative. Concerning the HVDC option at Grizzly, we will consider the issue of common mode outage of the Project HVDC facility and the PDCI outage during the WECC Phase 1 Rating Study for the proposed project.

Comments received from Michael Sidiropoulos PacifiCorp.

16. Comments: Costs are stated to include "network upgrades" but the latter needs to be defined. If it is costs associated with collector systems for BC generation that should be stated.

Response: The network upgrade cost referenced in this report include facilities required for interconnection to the Project line to deliver renewable resources to and from the Project line and includes 500/230 kV bank in the Pacific Northwest and Nevada.

Additional upgrades may be identified during the WECC Phase 1 Studies at which time the network upgrade cost will be revisited and updated.

17. **Comments:** It should be stated that mitigation costs of system impacts (effects on other paths etc) are not included.

Response: The TAC analysis did not identify any new physical or operational constraints on existing transmission paths resulting from the Project. Most of the major transmission paths between Canada, the Pacific Northwest and California were loaded at or close to their Operational Transfer Capability (OTC) ratings in the studies, and there were no new overloads or voltage criteria violations resulting from any of the contingencies studied by the TAC with the Project in service. The tripping of some of the incremental generation resources was required for single and double line outages of the Project line. The preliminary power flow studies did not show any adverse impacts in other regions of the WECC interconnection.

The WECC Phase 2 Rating Process will ultimately determine the physical and operational constraints on other paths that will result from or be removed by the Project line. Any mitigation measure required will be identified and the network upgrade cost will be revised and updated.

18. **Comments**: Only technically feasible alternatives should be costed and included in the Table. There must be ways to make the all-AC alternative technically feasible (more compensation, 765 kv voltage etc).

Response: This comment is addressed by assuming cost of network upgrades along the existing PACI paths for the AC alternatives evaluated here. The upgrades including establishing new network ties between the Project line and the existing PACI facilities between Grizzly and Table Mountain Substations and modifying the Series compensation on the existing PACI facilities.

The technical analysis for the 765 kV alternatives was not carried out as the project cost analysis showed this to be the most expensive alternative. Also some earlier studies carried out by PG&E for transmission options within California showed a flowablity problem when the 765 kV line is operated in parallel with a series compensated 500 kV network.

Comments from Jim Beck- TANC

19. **Comments:** Thank you for the comments you made at the Stakeholders' meeting in Portland yesterday, regarding the lack of substantial analysis on the so-called "TANC Option" of a 500 kV line from Raven to Midpoint, as part of the California to Canada Project.

As you know, I have commented in the past that:
1) TANC was able to make scheduled power flow from Midpoint to Raven, but only with

substantial compensation; and
2) TANC believes that it is a WECC shortcoming -- and not a shortcoming of this Project -- that none of the other substantial line additions announced by PacifiCorp and Idaho Power are modeled in the Base Cases used for the Project analyses.

With more study, and with the inclusion of models for the above-mentioned line additions, we believe it is highly likely that the "TANC Option" can be made to work. Such modeling and studies are also within the timeline for the California to Canada Project completion. It is likely that we will continue our studies and analysis of this path.

In the TAC Report, we believe the authors should take care to see that NO statements are made at this time regarding the viability of the "TANC Option". The Report should state that further analysis of this option will be required to establish its potential.

I appreciate the opportunity to provide these comments. In case you have not already done so, please include them in the brief section that discusses the TANC portion of the Work

Response: In accordance with Jim's comments PG&E has clearly stated the results of the TANC study in Preliminary Analysis section and in the Summary section. The draft language was reviewed by Mr. Dave Larsen of Navigant Consulting and is as follows:

Summary Section:

It should be noted that this recommendation does not rule-out the possibility that another alternative could be implemented to access resources in British Columbia or the Pacific Northwest. Completion of technical studies of other transmission projects in Idaho~~,~~ and eastern Nevada may lead to development of a transmission alternative to Northern California from eastern Nevada and Idaho.

Section 4- Preliminary Technical Study (under the heading other alternative studied)

AC-S3

The analysis by TANC showed it was able to make scheduled power flow on the segment of the Project line from Midpoint Substation to Raven Substation, but only with substantial compensation on the Project line and the use of a phase-shifting transformer. In this analysis other transmission projects in Idaho, Pacific Northwest, and Nevada now in WECC regional planning review were not modeled. TANC will continue to study this alternative to establish its full potential by modeling the transmission project development in eastern Nevada and Idaho.

As to Jim Beck comments on the short comings of the WECC process on interaction with transmission project still under development , the Project steering committee recognized this and is working with WEEC staff and its committees to get guidance on the treatments of such projects under development or review .

.

Section 6

Findings and Recommendation

Findings

TAC completed the cost analysis and preliminary power flow studies for a number of alternatives developed during regional planning review process for the Canada/Pacific Northwest to Northern California transmission project. The findings are discussed here.

TAC developed and evaluated costs for thirteen transmission alternatives to deliver 3000 MW of capacity from renewable resources in Canada and the Pacific Northwest to Northern California. The alternatives included HVAC, HVDC and Hybrid connections. The cost evaluated was: a) the Project cost, b) the Network Upgrade cost.

A summary of the preliminary project cost from source-to-sink are shown in the table below.

Import Capability in MW	Source-Sink Cost[19] ($ billions)		
	HVAC	HVDC	Hybrid (HVAC/HVDC)
1500-1600	4.6	4.1-4.3	
3000-4500	5.5-7.3	5.5	4.7-5.2

TAC also completed a preliminary technical analysis of a few alternatives which included several of the AC alternatives and Hybrid alternative. PG&E evaluated inland alternatives to Canada and Pacific Northwest. Sea Breeze evaluated the WCC and TANC evaluated the AC alternative to Midpoint substation.

The findings of the preliminary technical analysis showed a HVAC connection from Selkirk Substation (BC) to Northern California without network interconnection in the Pacific Northwest has many technical issues such as a large amount of reactive support requirements which may not be easy to coordinate and manage. With no network connection along this long AC transmission line, the system performance was shown to be extremely sensitive to minor changes in the shunt compensation levels along this line and the contingency cases were very difficult to solve. This alternative was deemed infeasible for further evaluation.

[19] *The cost estimates in the table are based on unit cost and not on engineering review and are subject to change based on subsequent information, analyses and further feasibility consideration. The cost estimates do not include any cost associated with permitting issues. The cost estimates are in 2006 dollar value and don not include escalation.*

Preliminary analysis for HVAC alternative with network connections in the Pacific Northwest showed flowablity problem on the Project line. Analysis showed that to get the desired flow on the Project line significant reduction in series compensation along the existing PACI may be required. This will negatively impact the existing OTC rating of the PACI. One option considered for mitigating this adverse impact is to establish additional ties between the Project line and existing PACI facilities, and changing series compensation on the existing PACI in order to achieve balanced flow along the existing PACI and Project line facility. The cost estimates for AC alternatives includes the cost of facility upgrades required to achieve the desired system performance for the AC alternative.

The preliminary evaluation of the Hybrid alternative showed the ability to transfer up to 3000 MW of capacity to Northern California from Canada and Pacific Northwest with no adverse impact. Although a thorough analysis is needed, the Hybrid connection may offer some regional benefit in relieving the congestion on some paths in the Pacific Northwest.

One of the Hybrid alternatives models a 950 mile transmission facility consisting of a 500 kV HVAC line from Selkirk-BC to Grizzly area-OR, and a 500 kV Bi Pole HVDC line from Grizzly area-OR to Tesla Substation-Northern California with intermediate connections in the Spokane area, the Lower Snake area or the McNary area in WA.

Based on the results of this analysis, the Hybrid alternative was found to be superior to the other alternatives:

- Better power flow controllability compared to AC Options
- More effective voltage regulation than AC Options
- Most cost effective alternative

In addition, the AC/DC Hybrid alternative could help mitigate congested paths in the Pacific Northwest.

Recommendations:

Based on the findings from this work, TAC recommends that the Hybrid transmission line alternative be further evaluated in Phase 1 of the WECC Project Rating Review Process.

The conceptual project description for the WECC Phase 1 Rating study is:

- A combination of 500 kV AC double circuit tower line +/-500 kV bi pole HVDC line with HVDC termination at Tesla sub
- Proposed rating: up to 3000 MW, north to south
- Terminations at Selkirk substation in BC and Tesla/Tracy substations in Northern California
- Potential intermediate connections pending results of the Phase 1 study:

- AC connection in the Spokane area in WA (as an example Beacon or Devil's Gap substation)
- AC connection at McNary (Lower Columbia area), or Lower Monumental (Lower Snake area) in WA
- AC interconnection at Grizzly area OR
- HVDC terminals at McNary or Lower Monumental in WA or at Grizzly area OR
- Potential third HVDC terminal- Round Mountain Substation

The scope for WECC 1 rating process for the preliminary project description listed above is:

- Conduct studies to demonstrate the proposed bi-directional non-simultaneous rating.
- Develop a preliminary Plan of Service, including intermediate connections and upgrades to address system impacts

It should be noted that this recommendation does not rule-out the possibility that another alternative could be implemented to access resources in British Columbia or the Pacific Northwest.

- Potential third HVDC terminal- Round Mountain Substation

The scope for WECC 1 rating process for the preliminary project description listed above is:

- Conduct studies to demonstrate the proposed bi Directional non simultaneous rating.
- Develop a Preliminary Plan of Service

It should be noted that this recommendation does not rule-out the possibility that another alternative could be implemented to access resources in British Columbia or the Pacific Northwest. Completion of technical studies of other transmission projects in Idaho, and eastern Nevada may lead to development of a transmission alternative to Northern California from eastern Nevada and Idaho.

Attachment 1

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

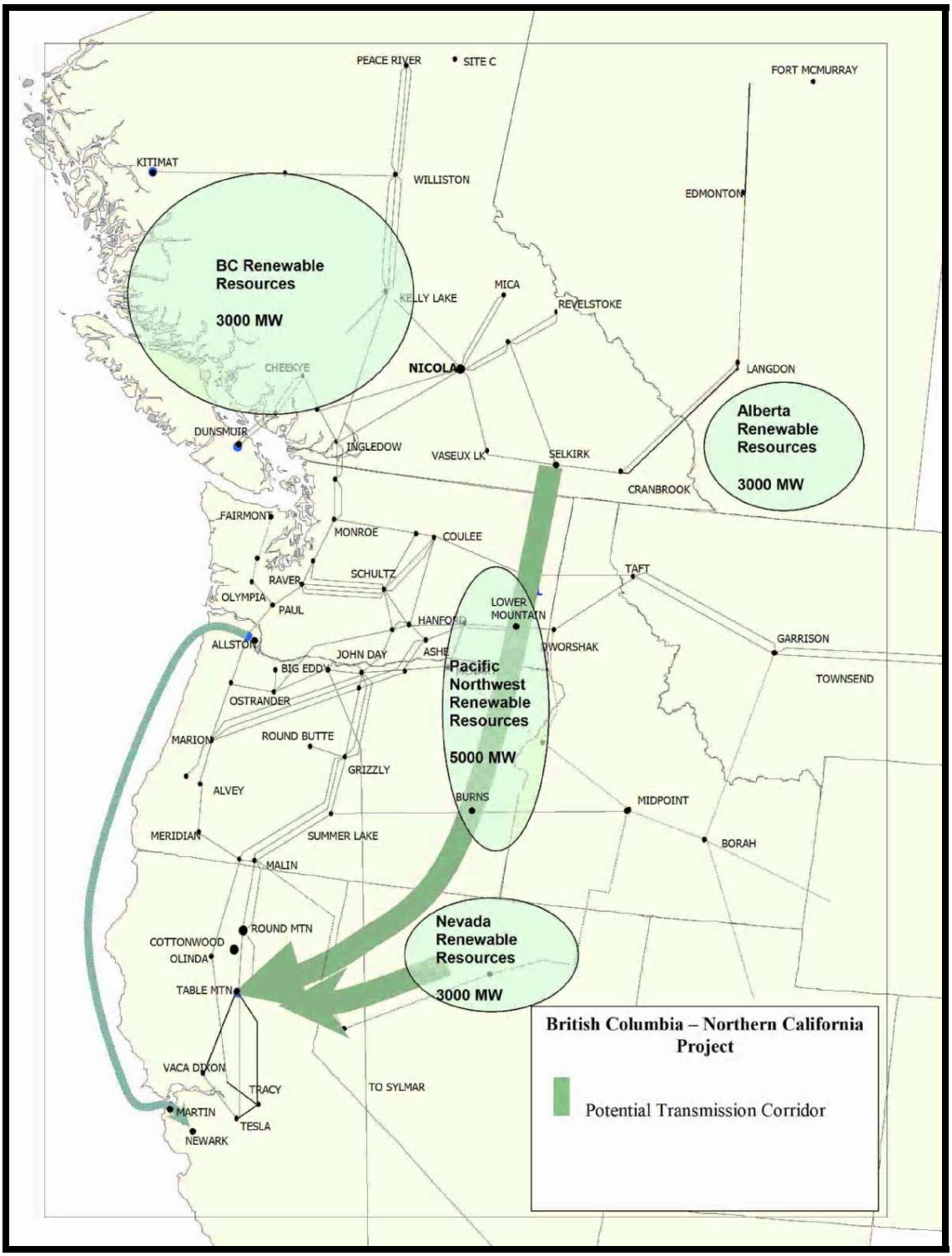
Bill Hosie -- TransCanada

Mariam Mirzadeh -- WAPA

Morteza Sabet -- WAPA

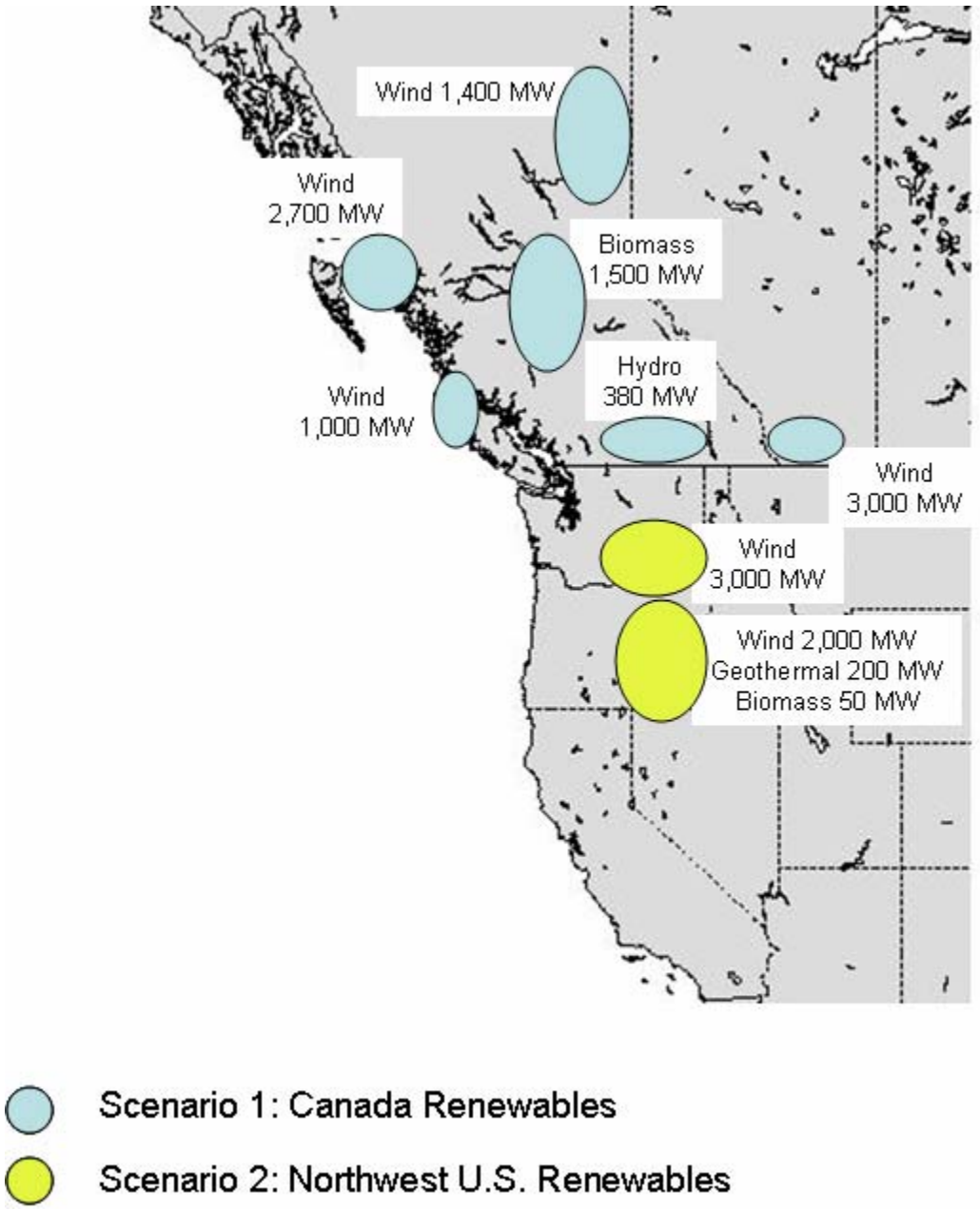
Sam Kwong -- Williams

Attachment 2.1



Attachment 2.2

Regions for development of resources in Canada and Pacific Northwest –provided by L/R working group



Attachment 3.1

Project Cost Estimate – Methodology and Assumption

Methodology

The methodology used in development of the cost estimate are based on unit cost for the transmission components and the assumptions used in the development of alternative for the inland or undersea corridors,. An excel spreadsheet workbook was developed listing the transmission components for each alternative and a summary of cost for the alternatives was developed. In this workbook each alternative has two worksheets namely; the project transmission cost and the local area upgrade cost.

The assumptions for the preliminary cost development for the transmission project alternatives are listed in the Attachment 4.1. Some of the factors impacting the cost estimates are the transmission line length and the number of connections established for the intermediate station, and these are briefly discussed below.

The cost for project transmission line is based on the measured straight-line distance on a geographical map increased by 15 percent to account for changes to the routing due to topographical impediments or changes to the transmission line alignments due to environmental or other ROW acquisition constraints. For the portion of the project transmission line in Northern California the ROW cost is assumed to be 50 % higher than the cost in Pacific Northwest or the eastern interconnection point in Nevada. Also for the undersea cable alternative additional transmission line reinforcements north of Allston substation up to Ingledow substation in British Columbia is assumed for accessing renewable resources in Canada. In this phase of the project review a detailed ROW study or environmental evaluation was not undertaken.

For the overland alternatives the project terminations are at Selkirk-BC, Canada in the north,
at the Midpoint substation- Idaho in the East and at Raven or Tesla substations- Northern California in the south. For the undersea alternative the terminations are at Allston substation –Oregon in the north and Martin and Newark Substations in the San Francisco Bay area in the south.

Intermediate terminations are assumed for interconnections to existing Pacific Northwest AC grid either for regional transmission benefit, for connection to the renewable resources in the region or station is established for switching in the series capacitor for the transmission project line. A breaker and a half configuration at each of these terminations are assumed for interconnection with existing grid.

For the inland alternatives the possible intermediate interconnections in the Pacific Northwest and Eastern Nevada are:

- Spokane area-WA, potential interconnection at Devil Gap or Becan Substation,
- Lower Monumental area-WA, potential interconnection at Lower Monumental Substation or
- McNary area-WA, potential interconnection point McNary substation or Boardman substation-OR,
- Burns area –OR, potential interconnection substation Burns substation
- Grizzly area-OR, potential substation Grizzly substation or
- Eastern Nevada area-NV, possible interconnection substations Valmy Substation.

Attachment 3.2

Assumptions

1	For overland (inland) alternatives uniform cost for ROW for 500 KV and 76kV lines in Canada/Pacific Northwest/Nevada.
2	For overland (inland) alternatives 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)	The Maximum rating for Single Circuit Transmission Line (SCTL)-500 kV is 1500 MW.
6)	The Maximum rating for Double Circuit Transmission line (DCTL)-500 kV is 3000 MW.
7	The Maximum rating for a single circuit 765 kV line is 3000 MW
8	Bi Pole DC Line Voltage rating +/- 500 kV
9	The Bi Pole DC line capacity 1500 or 3000 MW
10	The mileages for the new transmission line to California were based on straight line measurement and increased by15 percent to accommodate routing issues.
11	The Cost for 500 kV Double Circuit Tower Line is 160 % the cost of single circuit tower line.
12	The 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	Reactive compensation in the form of Static Var Compensator for 500 and 765 kV system is assumed.
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 overland(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 overland (Inland) alternatives.
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.

Attachment 3.3

Unit Cost Assumption

Transmission Line Unit Cost-AC System/Per Mile			
	Unit cost in $,000		
	ROW or Land cost	Construction cost	Total
I -Project Unit Cost- Transmission Line			
Canada-British Columbia/Alberta/Pacific Northwest/Nevada			
500 KV Single Circuit cost per mile	300	1,700	2,000
500 KV Double Circuit Line(1.6 times Single Circuit Line construction cost)	300	2720	3,020
765 KV Single Circuit Transmission Line construction cost(1.3 time the construction cost of 500 kV double circuit line)	300	3536	3,836
230 kV transmission line single circuit	300	1000	1,300
230 kV tranmission line double circuit(1.6 times single circuit)	300	1600	1,900
Bi Pole HVDC Transmission line +/- 500 kV (0.8 time the construction cost of single circuit 500 kV line)	300	1,360	1,660
BCTC 500 KV SCTL line cost candain $2.4 million per mile, assuming 0.956 conversion rate			2,200
California			
500 KV Single Circuit cost (CA Row or land cost 1.5 times Pacific Northwest)	450	1,700	2,150
500 KV Double Circuit Transmission Line (CA Row or land cost 1.5 times Pacific Northwest and 1.6 time the construction cost of single circuit 500 kV line)	450	2720	3,170
765 kV Single Circuit Line (Land or ROW CA 1.5 times the Row cost in Northwest and 1.3 times the construction cost for double circuit 500 kV line in California	450	3536	3,986
230 kV transmission line single circuit	300	1000	1,300
230 kV tranmission line double circuit(1.6 times single circuit)	300	1600	1,900
Bi Pole HVDC Transmission line +/- 500 kV *Over Land* (0.8 time the construction cost of single c	450	1360	1,810
DC line - Bi pole (Submarine Cable)			
DC Line Bi Pole -two cables (Submarine Cable -See Breeze Option)			2,615
II -Local Area Transmission Reinforcement cost			
Reconductor existing 500 kV line			1000
Reconductot existing 230 kV line Single circuit			500
III-Terminal Equipment AC System			
500 KV complete BAAH Bay (3 Breakers for two elemnet termination)			3,400
500 Kv with two breakers			2,300
500 kV Breaker			1,100
765 KV complete BAAH Bay (3 Breakers for two elemnet termination)			4,420
230 kV breaker			1,000
500/230 kV 1134 MVA bank (Three Single Phase Units $8 million/phase)			24,000
765/500 KV or 765/230 kV1134 MVA bank (Three Single Phase Units $8 million/phase)			31,200
230/115V or below bank			10,000
500 kV Series Compensation per bank			10,000
765 Kv seriss compenstation 1.3 times cost of 500 kV bank			13,000
Reactive Support +/-300 MVAR SVC @ $100/KVAR			30,000
IV -HVDC Station Equipment			
Converter Bi Pole 1500 MW (See Breeze WCC project I)			
Allston			200,000
Martin			120,000
Newark			120,000
Converter Bi Pole 3000 MW (one at each terminal) Frontier line project			500,000

Attachment 3.4

Sample of Project Transmission Line cost for alternative AC-S1

Preliminary Draft: Scenario AC-S1: Import 3000 MW from Canada - 500 kV DCT-Project cost

	Transmission Line Asset			Substation Asset						
	Mileage Cost in $,000			Component and Cost in $,000						
Transmission Asset	kV	Distance in miles	Cost	kV	Number of units or sets	Transformer	Breaker and Bay	Series compensation	Reactive Support	Projection and RAS
Canada										
DCTL- Selkirk BC- US/Canada Border	500	14	$41,676							
Complete 500 kV Bay(Three breakers)-Selkirk				500	1		$3,400			
500 kV Bay(two breakers)-Selkirk				500	1		$2,300			
Series Compensation-Selkirk				500	2			$20,000		
Reactive Support (+/- 300 MVAR)				500	1				$30,000	
Protection and RAS				500						$6,000
Total		**14**	**$41,676**		**5**	**$0**	**$5,700**	**$20,000**	**$30,000**	**$6,000**
Pacific Northwest-Washington State										
DCTL- US/Canada Border-Spokane area sub	500	110	$333,408							
Complete 500 kV Bay(Three breakers)-Lower Monumental				500	2		$6,800			
500 kV Bay(two breakers)-Spokane area sub				500	1		$2,300			
Series Compensation-Spokane area sub				500	4			$40,000		
Reactive Support (+/- 300 MVAR)				500	1				$30,000	
Protection and RAS				500						$9,000
DCTL- Spokane area sub-Lower Monumental	500	110	$333,408							
Complete 500 kV Bay(Three breakers)-Lower Monumental				500	2		$6,800			
500 kV Bay(two breakers)-Lower Mounmental				500	1		$2,300			
Series Compensation-Lower Monumental Sub				500	4			$40,000		
Reactive Support (+/- 300 MVAR)				500	1				$30,000	
Protection and RAS				500						$9,000
Total	**500**	**221**	**$666,816**		**16**	**$0**	**$18,200**	**$80,000**	**$60,000**	**$18,000**
Pacific Northwest-Oregon										
DCTL- Lower Monumental Sub -Burns Sub	500	207	$625,140							
Complete 500 kV Bay(Three breakers)-Burns Sub				500	2		$6,800			
500 kV Bay(two breakers)-Selkirk				500	1		$2,300			
Series Compensation- Burns Sub				500	4			$40,000		
Reactive Support (+/- 300 MVAR)				500	1				$30,000	
Protection and RAS-Burns Sub				500						$9,000
Total		**207**	**$625,140**		**8**	**0**	**$9,100**	**$40,000**	**$30,000**	**$9,000**
Burns Sub OR to Raven Sub CA										
DCTL- from Burns Sub to Raven Sub										
Burns Sub to Nevada Border	500	115	$347,300							
Nevada Border to CA Border	500	101	$305,624							
CA Border to Raven Sub	500	51	$160,402							
Complete 500 kV Bay(Three breakers)-Raven Sub				500	1		$3,400			
500 kV Bay(two breakers)-Raven				500	1		$2,300			
Series Compensation-Raven Sub				500	2			$20,000		
Reactive Support(+/- 300 MVAR)-Raven Sub				500	1				$30,000	
Protection and RAS				500						$9,000
Total		**267**	**$813,326**		**5**	**$0**	**$5,700**	**$20,000**	**$30,000**	**$9,000**
Sub Total		**708**	**$2,146,958**			**$0**	**$38,700**	**$160,000**	**$150,000**	**$42,000**

Attachment 3.4

Sample of Local Area Network Upgrade cost for alternative AC-S1

Preliminary Draft: Scenario AC-S1: Import 3000 MW from Canada - 500 kV DCTL -Transmission reinforcement cost

	Transmission Line Asset			**Substation Asset**						
	Component Cost in **$.000**					Component and Cost in **$.000**				
Transmission Asset	KV	Distance in miles	Cost	KV	Number of units or sets	Transformer	Breaker and Bay	Series compensation	Reactive Support	Projection and RAS
Canada										
Transmission Line Upgrades										
500 kV SCTL Skeena-Telkwa	500	89	$205,062							
500 kV SCTL Telkwa-Williston	500	192	$440,238							
500 kV SCTL Williston-Kelly Lake	500	206	$473,220							
Substation Upgrades										
Complete 500 kV Bay(Three breakers)				500	1		$3,400			
500 kV Bay				500	1		$1,100			
500/230 kV Transformer 1134 MVA				500	3	$72,000				
Breakers 230 kV				230	6		$6,000			
Protection Upgrade										$11,000
Other reinforcements			$50,000							
Total		488	$1,168,520		11	$72,000	$10,500	$0	$0	$11,000
Pacific Northwest-Washington State										
Transmission Line Upgrades										
Substation Upgrades										
500KV Bay(two Breakers) Spokane area sub										
500/230 kV Transformer 1134 MVA										
Breakers 230 kV										
Protection Upgrade										
500KV Bay(two Breakers) Lower Monumental										
500/230 kV Transformer 1134 MVA										
Breakers 230 kV										
Protection Upgrade										
Total										
Pacific Northwest-Oregon										
Transmission Upgrades										
Substation Upgrades										
500KV Breaker Burns Sub										
500/230 kV Transformer 1134 MVA										
230 kV Breakers										
Protection Upgrade										
Total										
Nevada										
Transmission Upgrade										
Substation Upgrade										
Total		0	$0		0	$0	$0	$0	$0	$0
Sub Total		**488**	**1,168,520**	**0**	**11**	**72,000**	**10,500**	**0**	**0**	**11,000**

Attachment 4.1

Project Case Development: The major elements considered in development of the project cases are:

- Transmission Alternatives considered for the study
- Incremental Resource Addition-Identify load flow areas for resources addition
- Generation Retirements- Identify areas where generation will be retired to achieve desired flow on the proposed alternative
- Transmission System Model- Based on alternative selected

Transmission alternative for technical analysis: some if the alternatives listed in table 2.2 were chosen for development of the project base cases. PG&E developed base cases and analyzed transmission system performance for the transmission line interconnection to Selkirk substation-BC Canada. TANC developed bases case and analyzed the transmission system performance for the transmission line alternative to Midpoint substation-Idaho.
Sea Breeze Corporation was the responsible party for developing the cases and analysis WCC alternative.

From the alternatives listed in Table 2.1 and 2.2 PG&E developed base case for following alternatives:

AC-S1 with CA-2 with no network connection in Pacific Northwest: 500 kV HVAC from Selkirk BC to Tesla and Elverta substation in Northern California with 3000 MW import from Canada

AC S1 with CA-2 with network connection: A 500 kV HVAC from Selkirk BC to Tesla and Elverta substation in Northern California with network connection in the Lower Snake area (Lower Monumental substation)-WA and in Burns area (Burns substation)-OR. 1500 MW import capability each from Canada and Pacific Northwest

HY-S14-Hybrid: A combination of HVAC and HVDC facilities. 500 kV HVAC from Selkirk BC to Grizzly area OR and 500 kV Bi Pole HVDC Grizzly area-OR to Tesla substation – Northern California with intermediate connection in the Spokane area, the Lower Snake area or the McNary area in WA. 1500 MW import capability each from Canada and Pacific Northwest

Incremental Resource addition for the technical analysis. L/R working group identified the regions of potential incremental renewable resource development in Canada, Pacific Northwest and eastern Nevada. These are shown in Appendix 2 attachment 2.1, which shows the potential maximum capacity available in each of the region. In addition to this L/R working group also provide information on the dependable capacity for the resources type in each region. The TAC investigated the following resource scenarios.

- Import of 3000 MW of capacity from Canada and
- Import 1500 MW each from Canada and Pacific Northwest.

For each of theses scenario TAC made assumption on the distribution[20] and dispatch of the incremental resources and these are listed in the table below.

Power Flow Bus Name	Resource Type	3000 MW from Canada		1500 MW each from Canada and Pacific Northwest	
		Max Capacity MW	Dispatched MW	Max Capacity MW	Dispatched MW
Skeena 500 kV	Wind	2700	600	2700	300
GMS 500 kV	Wind	1400	350	1400	175
	Hydro	900	750	900	375
Dunsmuir 500 kV	Wind	1000	250	1000	125
Ashton Creek 500 kV	Hydro	360	300	360	180
Cranbrook 500 kV	Wind	3000	750	3000	375
Mid C Area Vantage 500 kV	Wind 5000 MW				750
Mid C area McNary 500 kV					750

Table 4.3 Incremental resource dispatch in Canada and Northern California

At each of the locations the wind units were modeled at with zero reactive output at 500 kV bus, whereas the hydro units at these busses were modeled with a range of +/- 90 % pf capability.

Generation Retirements: The import on the project transmission line from Canada, Pacific Northwest was achieved by assuming generation unit retirements in the San Francisco Bay area, 3000 MW of generation was retired in the San Francisco Bay area.

Project Transmission Facility Models: The AC transmission line model for the project was based on the assumption of homogenous construction (tower and conductor) throughout the length of the line. For the AC line the line is broken out in to segments with intermediate stations for either network connections, or integration of renewable resources, or in some case for insertion of series capacitors for the line segment. Segments of the lines are series compensated. The level of series compensation is adjusted to ensure desired flow on the project line is achieved. Each circuit of the transmission line is capable of having a capacity of 1500 MW under normal condition.

[20] Assumption for distribution were made such that required capacity for delivery can be established between the regions without re dispatching any of the existing generation in the power flow case. It is to be noted the different levels of incremental generation with in BC

For the HVDC line the and termination the IPP(Intermountain Power Project) model was used as a model for the project. A detailed model will be developed in the WECC Phase I rating study.

Reactive compensation at the termination and intermediate stations along the project line are modeled to achieve the desired pre and post contingency voltage performance. The types of reactive compensation modeled are the shunt capacitors, shunt reactors and SVC (Static Var Compensator) or synchronous condensers for dynamic voltage support under contingencies.