Canada–Northwest–California Transmission Options Study

Northwest Power Pool
Northwest Transmission Assessment Committee
Canada-NW-California Study Group

Co-Chair: Marv Landauer, Bonneville Power Administration
Co-Chair: Gary DeShazo, California Independent System Operator

16 May 2006

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1. Executive Summary

In 2004 the Northwest Transmission Assessment Committee (NTAC) convened a study group to investigate options to increase the capacity of the transmission system between resources located in Western Canada or the Pacific Northwest and loads located in California. The group was known as the Canada-Northwest-California (CNC) Study Group and included representatives from Northwest and California utilities, merchant developers and other interested parties. This report presents the findings of the CNC Study Group.

The Study Group developed an inventory of potential new generation resources in Western Canada and the Pacific Northwest that could be available for inter-regional trade. Using this inventory as a basis, eighteen AC and DC transmission options were considered ranging in capacity from 1500 MW to 3200 MW with costs ranging from $2.2 billion to $6.4 billion[1]. These transmission options included projects proposed by merchant transmission companies as well as some developed through brainstorming workshops with interested WECC transmission planning experts. For each transmission option detailed preliminary cost estimates were prepared. Differences between public entity and merchant cost estimates for the DC options are noted in the report. A high level map summarizing the various options considered is included as Figure 1 of this Executive Summary. For detailed descriptions of the transmission options refer to Section 5.3 of the report or Appendix 2.

Generic costs for new generation from the Northwest Power and Conservation Council (NWPCC) and others were then used in conjunction with the transmission development costs to assess the cost of delivered energy to the Northwest and to California. A sample of cost of delivered energy results[2] are shown in Figures 2 for low, medium, and high natural gas price forecasts[3] and a green house gas adder of $8/ton. As most of the AC and DC options can deliver energy at intermediary points, the bar chart is structured to reflect possible delivery points in the Northwest and California. The transmission option analysis and cost of delivered energy spreadsheet used for this assessment is available on the NTAC website to help Load Serving Entities and resource developers consider the viability of various resource and transmission development scenarios.
Weblink: *www.nwpp.org/ntac/pdf/CNC_Options_Analysis_Tool_-_2006.xls*

This report will be submitted to WECC with the expectation that the Transmission Expansion Planning Policy Committee will analyze the economic benefits of selected projects shortly after the Committee begins its work.

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[1] All costs in this report are in 2005 $US and transmission project costs include overheads, interest during construction and a contingency.

[2] The AC costs referenced in the Bar Charts are generally Public Utility capital costs and the DC costs are Merchant capital costs. Both Public Utility and Merchant projects are assumed to receive the same financial treatment, namely a 70/30 debt/equity ratio, a nominal interest rate of 6% on the debt and a nominal return of 12% on the equity, and an income tax rate of 33.6%.

[3] The Gas Price Forecasts used in the CNC study are consistent with the forecasts used in the SSG-WI (Seams Steering Group – Western Interconnect) 2015 IRP-RPS Reference Case, Production Cost Modeling Results that can be found at http://ssgwi.com in the working groups, planning section.

If it is determined that a second CNC study group be convened to perform more detailed analysis of selected options it is recommended that the next stages include the following:

1) Refine the selected options: in this phase the group would work together to refine each selected option based on the results of the economic analysis.

2) Complete Analysis of selected options, including:
    i. Powerflow and Transient Stability studies for DC and Hybrid options, including the receiving end transmission;
    ii. Transient Stability for AC options

3) Determine additional benefits:
    iii. Quantify additional North-to-South Transfer Capability
    iv. Quantify South to North Transfer Capability
    v. Quantify the RAS reduction

4) Compare the selected options against common measures, including:
    vi. Reliability improvements,
    vii. NWPCC Portfolio Risk Analysis;
    viii. Congestion improvements;
    ix. Capital cost;
    x. Economic gains;
    xi. Loss impacts

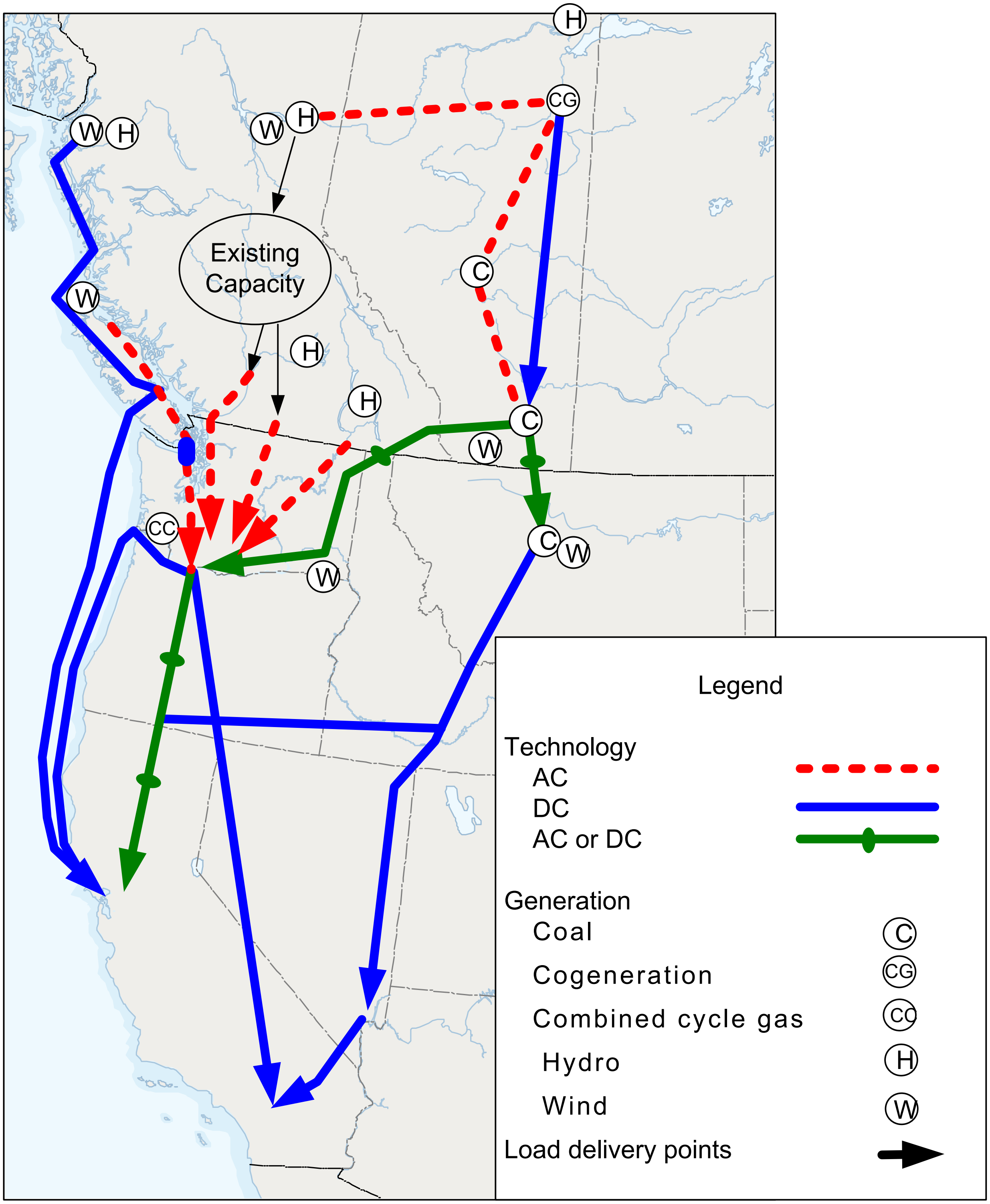
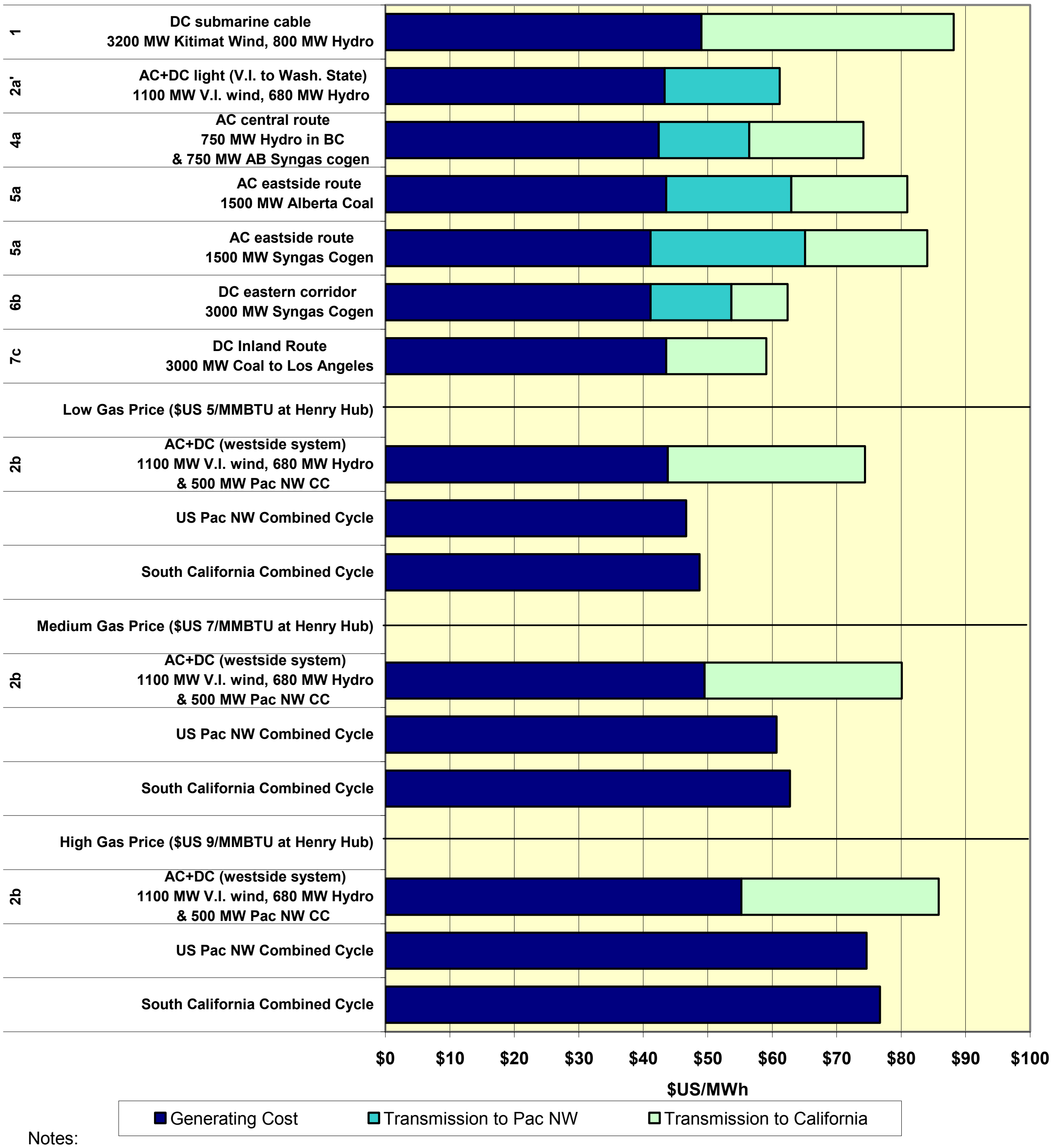


Figure 1: Alternative Corridors and Technologies Studied

Figure 2: Representative costs of delivered energy for Medium Gas Forecast
Real Levelized Unit Costs, 2005 $



Notes:

1. Wind costs assumed to be between $1,300 per kW and $1,700 per kW, hydro costs assumed to be $2,600 per kW. The wind and hydro projects are assumed to be in close proximity.
2. Syngas cogen refers to Ft. McMurray Synthetic Gas-fired Generation ($5.07/MMBTU and a heat rate of 5,800 BTU/kWh)
3. Combined cycle refers to a plant with a heat rate of 6,925 BTU/kWh
4. Greenhouse gas adder at US$8/ton.

2. Background

By 2016, it is forecast that California will need to procure approximately 40,000 MW of additional capacity in order to meet its expected peak demand of 78,000 MW (including 15% reserve margin)[4]. California's Renewable Portfolio Standard requires that 20% of its load (energy) be supplied by renewable resources by 2010, and the California Energy Action Plan II intends to press forward Governor Schwarzenegger's goal of meeting 33 percent of statewide electric power supply with renewable energy by 2020[5]. A substantial portion of California's capacity and renewable energy requirements will need to be supplied with out-of-state resources. In addition, Pacific Northwest and Nevada utilities are also interested in costs associated with bringing potential resources in the Northwest region to their growing load.

In anticipation of these forecasted needs for electricity, resource developers from across the Western US and Canada have been pondering how their specific generation projects could be brought to fruition. In 2004, the Northwest Transmission Assessment Committee (NTAC) convened a study group with the mandate of identifying transmission options that could be used to connect new generation projects in Western Canada or the Pacific Northwest to loads in the Pacific Northwest, California and Nevada. The group was Co-chaired by Marv Landauer of the Bonneville Power Administration and Gary DeShazo of the California Independent System Operator. The group included experienced transmission planners from Alberta, British Columbia, California, Montana, Oregon and Washington drawn from Transmission Providers, Load Serving Entities, Resource Developers and Merchants. Membership at times also included regulatory and other interested parties, including the Northwest Power and Conservation Council. While the group had core members who were regular participants at meetings, the meetings were open to any interested party. Individual members and their companies are listed in Appendix 1.

By having NTAC facilitate the gathering of factual transmission information that will be freely available to all, it is hoped that discussions between Load Serving Entities and Resource Developers will be enhanced. In addition, it is hoped that by gathering a wide set of transmission reinforcement options that a consensus will emerge on some of the most reliable and cost effective ways to reinforce the WECC transmission grid.

3. Objective

The objective of the Canada-NW-California studies was to provide high-level information on the feasibility of potential transmission projects to transfer a variety of new resources out of Canada into the Northwest and California. This study did not investigate the particular interconnection requirements for individual resource projects. The analysis required to fully develop a plan of service for transmission projects of this magnitude would be very complex and could take several years.

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[4] California Energy Commission 2005 Integrated Energy Policy Report (CEC-100-2005-007-CMF): http://www.energy.ca.gov/2005_energypolicy/index.html

[5] California Energy Commission and California Public Utilities Commission (2005): *Energy Action Plan II - Implementation Roadmap for Energy Policies;* California Energy Commission (2005): *2005 Integrated Energy Policy Report - Committee Draft Report* CEC-100-2005-007-CTD (http://www.energy.ca.gov/2005publications/CEC-100-2005-007/CEC-100-2005-007-CTF.PDF)

4. Scope of Study

This study had five phases:

1) Transmission Options Development

The first step was to identify potential generation resources that could influence the development of the transmission grid from Canada though the Pacific North West and on to California. Using this information, information about projects under development and possible projects identified by experienced transmission planners, a set of 20 transmission development options was created. The options generally followed five different corridors thought the Pacific North West and used AC, DC, overhead and submarine transmission technologies.

The alternatives are summarized in Section 5.3 and detailed in Appendix 2. The cost estimates for the alternatives are summarized in Section 7 and detailed cost estimates for each alternative are included in the Transmission Option Analysis Spreadsheet:
www.nwpp.org/ntac/pdf/CNC_Options_Analysis_Tool_-_2006.xls

2) Power System Analysis

Power flow and some reactive margin analysis was carried out on the AC options and the AC components of hybrid AC/DC options to confirm the proposed reinforcements were adequate for an additional 1500 MW of transfer capacity.

Power system analysis was not carried out on the DC options as the bulk of this analysis will be associated with the local integration of the projects.

Local integration studies were not carried out for either the resource or load terminals of either AC, DC or the hybrid options. As options are selected for further study or development, integration studies will be required.

3) Transmission Capital Cost Estimates

Generic capital cost estimates were developed for each component of the alternative transmission systems. The component costs were developed for various geographies, incumbent transmission owner and merchant project.

Modular cost estimates were developed for each alternative by tabulating all of the system components and applying the generic cost estimates. The modular cost estimate process enables resource developers, or customers located mid-way along a transmission path to be able to develop their own high-level custom estimate using the NTAC data.

4) **Loss Analysis**

The approach to analyzing losses was to assume that the new power flow would be carried exclusively over the new facility. The loss factor for each type of line and station was developed and used in conjunction with the capacity factor or each resource mix evaluated.

In cases where existing transmission capacity is used, the average incremental losses are assessed and allocated to the option. In cases where there is counter flow, the decremental losses are assessed and credited to the alternative.

This approach to evaluating losses should be considered as a loss index as opposed to a highly accurate approach to assessing losses. Those alternatives that are chosen for further evaluation or development will need further loss evaluation.

5) **Cost of Delivered Energy**

The cost of delivered energy for each of the eighteen alternatives was developed with an average of two generation complements per alternative.

The generic generation costs and heat rates were generally provided by the NWPCC. The gas price forecast used was that used in the recently completed SSG-WI production model of the Western Interconnection[6].

The analysis was done for delivery of Canadian energy to the Columbia River area and both northern and southern California.

In order to facilitate discussion amongst loads and resource developers a cost of delivered energy tool was developed with a few examples. The intent was to empower buyers and sellers to explore different scenarios in preparation for negotiating power purchase agreements and transmission purchase agreements. This tool is available on the NTAC web page.

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[6] The Gas Price Forecasts used in the CNC study are consistent with the forecasts used in the SSG-WI (Seams Steering Group – Western Interconnect) 2015 IRP-RPS Reference Case, Production Cost Modeling Results that can be found at http://ssgwi.com in the working groups, planning section.

5. Transmission Option Development Process

5.1 Potential Resource Development

The starting point for investigating transmission options that could connect potential generation projects in Western Canada and the Pacific Northwest with loads in the Pacific Northwest, California or the Desert Southwest involved identifying generation resources that could potentially be developed for interregional trade. The criteria used for identifying resources were:

- Potential development time frame within 15 years (i.e. in service before 2020);
- Technically feasible and under consideration by some entity;
- Available for interregional trade (i.e. not committed to serve a domestic load);
- Potential net incremental capacity for interregional trade above 2004 levels.

A snapshot of the resulting resource potential is shown in Figure 3. The capacity values of Figure 3 are rough estimates of potential based on current information and do not necessarily represent the full developable capacity of the respective resources, nor the portion that might be available for export by 2015.

Representative performance and cost estimates were developed for power generation projects using the resources of Figure 1, using publicly available information. These estimates are provided in Tables 1 (power plants) and 2 (fuels).

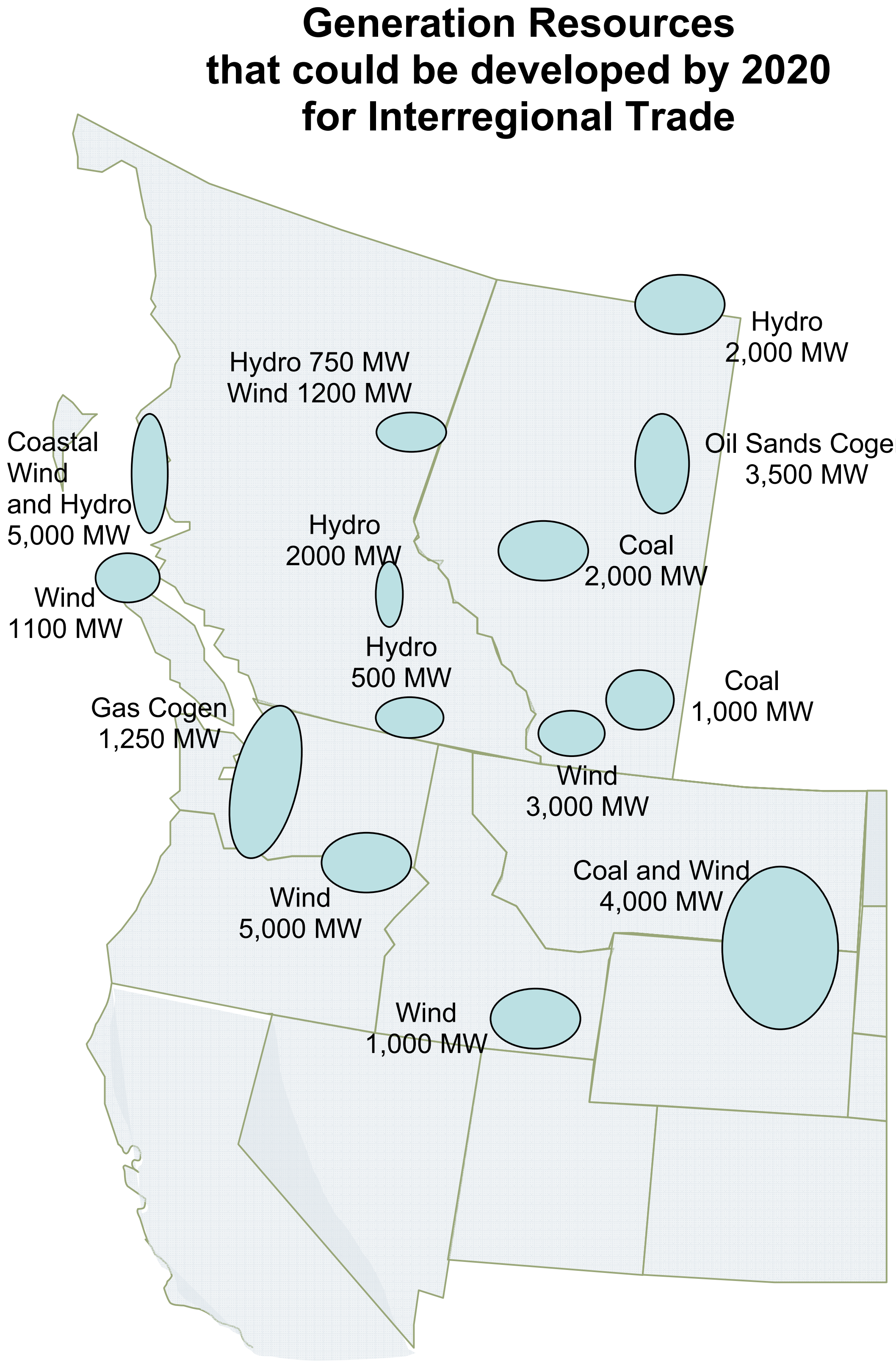

Figure 3: Snapshot of Potential Generation Resources for Interregional Trade

Plant Type/Location	**Fuel** (See Table 2)	**Unit Capacity[7] (MW)**	**Heat Rate[8]** (Btu/kWh)	**Avail-ability[9]**	**Capital Cost[10] ($/kW)**	**Fixed O&M[11] ($/kW/yr)**	**Variable O&M ($/MWh)**	**Project Life (yr)**	**Levelized Cost ($/MWh)[12]**	**Source**
Combined-cycle (Alberta)	Nat Gas - AB	465	7000	92%	$740	$24	$3.20	30	$59.30	NPCC[13]
Combined-cycle (US, California)	Nat Gas - CA	520	7000	92%	$660	$21	$3.20	30	$61.30	NPCC[13]
Combined-cycle (US, W. of Cascades)	Nat Gas - PNW	525	7000	92%	$650	$21	$3.20	30	$59.20	NPCC[13]
Conventional Coal (Alberta)	Coal - AB	400	9580	84%	$1410	$68	$2.00	30	$39.50	NPCC[13]
Conventional Coal (US, E. MT)	Powder R. Coal	400	9580	84%	$1410	$68	$2.00	30	$39.50	NPCC[13]
Hydro (BC)	--	900	--	58%	$2192	$15	$4.40	70	$56.50	BC Hydro[14]
IGCC[15] (Alberta)	Coal - AB	374	8790	83%	$1790	$88	$1.70	30	$54.40	NPCC[13]
IGCC[15] (US, E. MT)	Powder R. Coal	374	8790	83%	$1790	$88	$1.70	30	$54.40	NPCC[13]
Oil Sands CHP[17] (Ft. McMurray)	Nat Gas - AB	180	5800	95%	$673	Inc. in VrOM[16]	$5.00	25	$51.50	Northern Lights[17]
Oil Sands CHP[17] (Ft. McMurray)	Oil Sands Syngas	180	5800	95%	$673	Inc. in VrOM[16]	$5.00	25	$46.90	Northern Lights[17]
Peaking Hydro (BC)	--	1860	--	1.3%	$220	$5	$4.73	50	$205.00	BC Hydro[14]

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[7] Site rating, lifecycle average.

[8] Higher heating value.

[9] Capacity factor for wind and hydro.

[10] "Overnight" capital cost (exclusive of interest and escalation during construction).

[11] Including typical property taxes, insurance and capital replacements. Excludes fixed fuel cost.

[12] Levelized lifecycle busbar energy cost based on a capital charge rate of 7.47% (real) and full operating availability. No resource incentives or GHG penalties included.

[13] Northwest Power and Conservation Council. *The Fifth Northwest Electric Power and Conservation Plan.* December 2004. (http://www.nwcouncil.org/energy/powerplan/default.htm).

[14] Proxy costs for hydro resources in BC are taken from BC Hydro's 2006 Integrated Electricity Plan (http://www.bchydro.com/info/epi/epi8970.html)

[15] Integrated (coal) gasification combined-cycle. No CO2 separation.

[16] "Inc. in VrOM" is an abbreviation for "Included in Variable O&M"

[17] Costs for Oil Sands CHP (Combined Heat and Power) resources are based on in-house data provided by TransCanada. For further information on TransCanada see (http://www.transcanada.com/)

Plant Type/Location	**Fuel** (See Table 2)	**Unit Capacity[18] (MW)**	**Heat Rate[19] (Btu/kWh)**	**Avail-ability[20]**	**Capital Cost[21] ($/kW)**	**Fixed O&M[22] ($/kW/yr)**	**Variable O&M ($/MWh)**	**Project Life (yr)**	**Levelized Cost ($/MWh)[23]**	**Source**
Wind (BC N. Coast, Offshore)	--	300	--	44%	$2060	$58	$5.15[24]	20	$83.30	BC Hydro[25]
Wind (BC N. Coast, Onshore)	--	50	--	40%[26]	$1614	$53	$5.15[24]	20	$112.00	BC Hydro[25]
Wind (BC, N. Vancouver Island)	--	150	--	35%[26]	$1281	$37	$5.15[24]	20	$72.30	BC Hydro[25]
Wind (BC, Peace region)	--	200	--	39%	$1160	$38	$5.15[24]	20	$56.30	BC Hydro[25]
Wind (US, E. MT)	--	100	--	36%	$1110	$38	$6.30[27]	20[28]	$59.80	NPCC[29]
Wind (US, E. OR & WA)	--	100	--	30%	$1110	$38	$6.30[27]	20[28]	$70.90	NPCC[29]
Wind, Later development (US, E. OR & WA)	--	100	--	28%	$1110	$38	$10.75[27]	20[28]	$79.90	NPCC[29]

Table 1: Performance and cost assumptions for power generation projects (2005 US dollars)

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[18] Site rating, lifecycle average.
[19] Higher heating value.
[20] Capacity factor for wind and hydro.
[21] "Overnight" capital cost (exclusive of interest and escalation during construction).
[22] Including typical property taxes, insurance and capital replacements. Excludes fixed fuel cost.
[23] Levelized lifecycle busbar energy cost based on a capital charge rate of 7.47% (real) and full operating availability. No resource incentives or GHG penalties included.
[24] Includes shaping costs (from NPCC – Northwest Power and Conservation Council), no incentives.
[25] From *Assessment of the Energy Potential and Estimated Costs of Wind Energy in British Colum*bia. Prepared by Garrad Hassen for British Columbia Hydro and Power Authority, May 2005. (http://www.bchydro.com/rx_files/info/info26565.pdf).
[26] Value from SeaBreeze Power Corp. For further information on SeaBreeze refer to (http://www.seabreezepower.com/).
[27] Includes shaping cost, no incentives.
[28] 20 years is used in lieu of 30-year value in NPCC 5th Plan for consistency w/other wind cases appearing here.
[29] Northwest Power and Conservation Council. *The Fifth Northwest Electric Power and Conservation Plan.* December 2004. (http://www.nwcouncil.org/energy/powerplan/default.htm).

Fuel/Delivery Area	2005 Delivered Cost ($/MMBtu, HHV)	Price Escalation (%/yr)	CO2 Factor (lbCO2/MMBtu)[30]
Natural Gas – AB	$6.10	0%	117
Natural Gas – CA	$6.60	0%	117
Natural Gas – PNW	$6.32	0%	117
Coal - AB minemouth	$0.58	0%	212
Powder R. Coal - MT & WY minemouth	$0.58	0%	212
Oil sands syngas - AB	$5.00	-1.5%	195

Table 2: Fuel price assumptions and CO2 production factors (2005 US dollars)

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[30] U.S. Environmental Protection Agency standard CO2 factors (except oil sands syngas, from Northern Lights).

5.2 Existing WECC Transmission Grid

Alberta and British Columbia have an intertie between them consisting of a single 500-kV line and and two 138 kV lines. BC is connected to the Pacific Northwest primarily through two 500 kV lines between Vancouver, BC and Blaine, WA and two 230-kV lines, north of Spokane near the Boundary Project. The Pacific Northwest has a significant 500 kV network that spans Washington, Oregon, Idaho and Montana. The PNW has three 500 kV AC interties and one +/- 500 kV DC intertie with California. The principal paths and their existing ratings are summarized below in Table 3.

WECC Path	Transfer Path	Existing Planning Path Ratings
1	Alberta – British Columbia	East to West: 1000 MW West to East: 1200 MW
3	Northwest – Canada	North to South: 3150 MW South to North: 2000 MW
8	Montana – Northwest	East to West: 2200 MW West to East: 1350 MW
14	Idaho – Northwest	East to West: 2400 MW West to East: 1200 MW
26	Northern-Southern California	North to South: 4000 MW South to North: 3000 MW
65	Pacific DC Intertie	3100 MW bi-direction
66	COI	North to South: 4800MW South to North: 3675 MW
73	North of John Day	OTC: 8400 MW
75	Midpoint – Summer Lake	East to West: 1500 MW West to East: 400 MW

Table 3: Relevant WECC Paths Definitions and Ratings

Several of the paths listed in Table 3 are already congested during peak hours of the year. Consequently, in order to serve load growth in the western US with expected resource development located in Western Canada or the greater Montana area, the existing transmission system would need to be reinforced. A high level one-line diagram of the existing WECC bulk transmission system is shown in Figure 4.

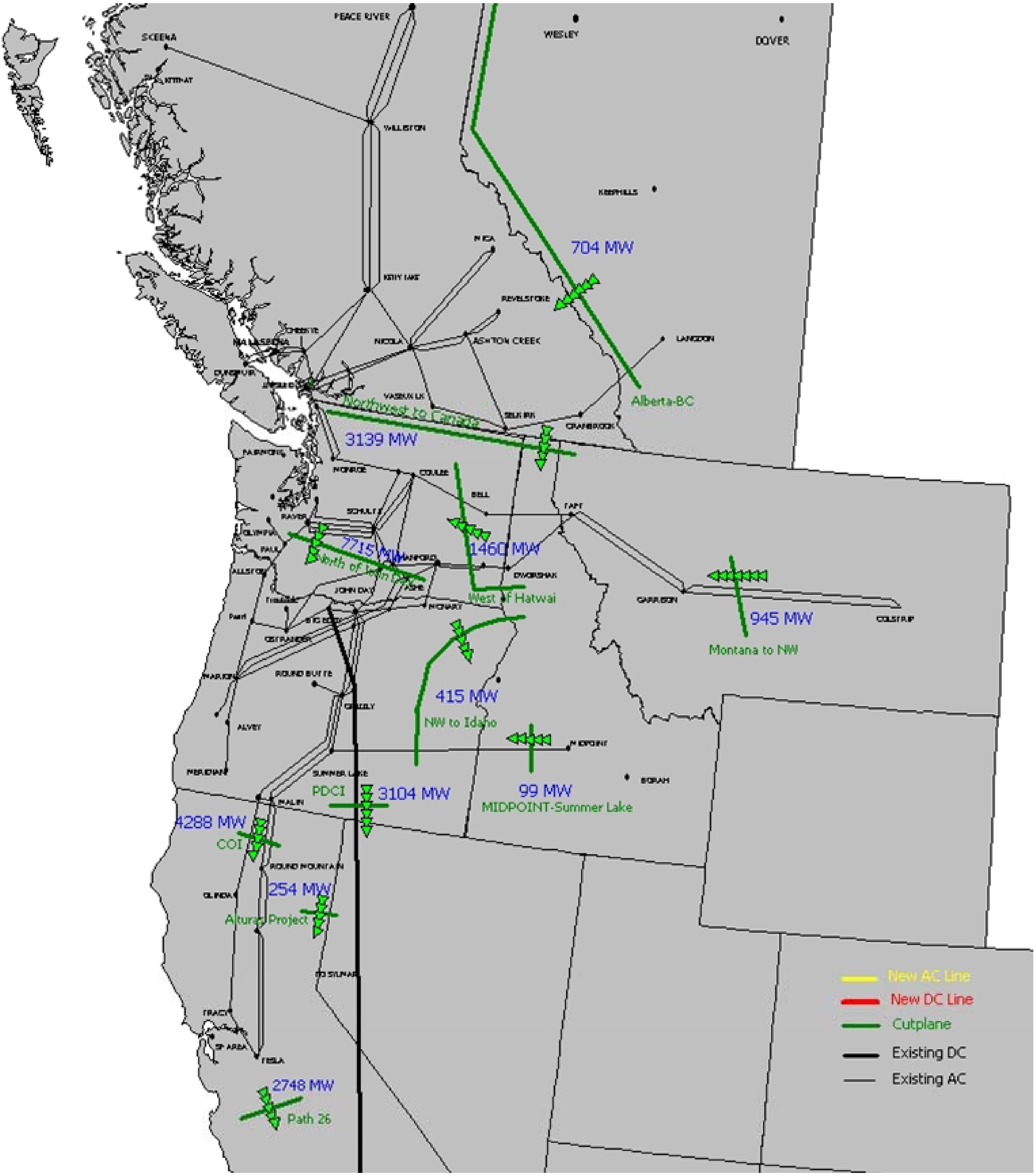

Figure 4: Cut plane and major tie flows for WECC 2007 Heavy Summer Base Case as modified for CNC study

5.3 Transmission Option Development (Phase 1: Reinforcements for the WECC Grid)

Taking into consideration the resource development options discussed above and known constraints, transmission options included in this study were identified through:

- Invitations to merchant transmission companies to participate in the study and provide the details associated with their projects;
- White boarding sessions with interested transmission planners to develop AC, DC and combined AC/DC hybrid transmission options that could integrate several of the proposed generation projects;
- Refining the transmission options that were identified prior to 2004 with insights gleaned from the transmission studies.

No siting analysis was done for the AC options other than to use professional judgment of plausible routes for the new transmission projects. There will undoubtedly be siting issues along each corridor with regional variations accounted for in the cost development discussed below. These routes are perceived as generally feasible and are not expected to introduce new N-2 planning limitations[31]. For the DC options some siting analysis has been performed by the sponsors of the particular projects.

Each option is shown extending from Canada to California however this analysis is designed so that projects can be terminated in the Pacific Northwest at the Columbia River. From the full option, one can determine not only what would be required to move energy from Canada into California but also from Canada to the Pacific Northwest or starting from areas within the Pacific Northwest to California. This information is intended to be used as building blocks to provide information on more options and alternatives than those presented. In all cases there will be different collector system requirements to integrate specific generation projects and for the DC options in particular, distribution requirements at the receiving ends.[32]

To load up these new line projects for simulation, generation was selected at the far northern end of the lines and load was increased in California to absorb that energy. There is no attempt here to make any judgment on the consumer value of the resources actually connected; they are only used to test the ability of the new line projects to move energy to the south.

High level maps of the options studied are shown below along with summaries of each option, including a levelized transmission charge ($/MWh) assuming 100% capacity factor. The details of the options, including routes and the potential resources that were considered in their development are shown in Appendix 2.

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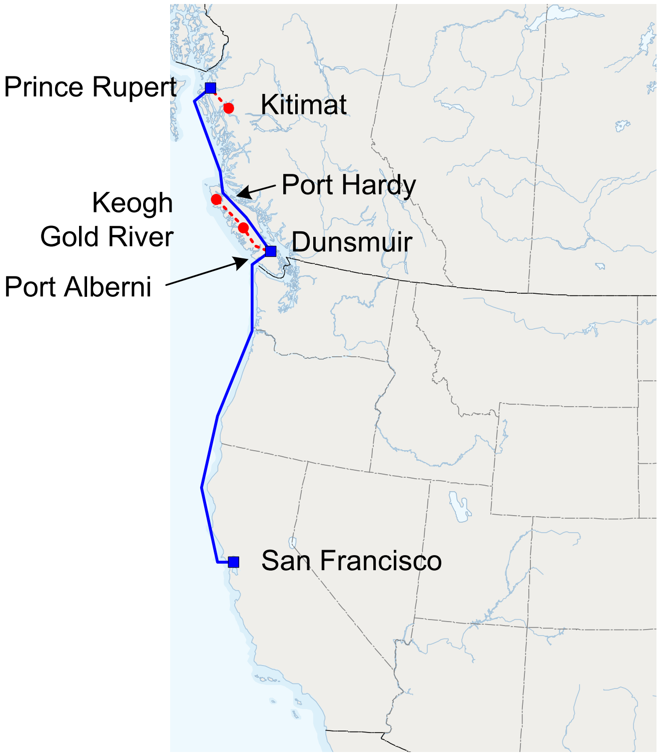
[31] New routes will not create new N-2 common Right-Of-Way outages as defined in the WECC planning guidelines.

[32] An advantage of routing DC submarine cables through San Francisco Bay is that it could provide new sources of supply for downtown San Francisco without the challenges and costs of acquiring land for new transmission rights of way.

Fig 5a: Option 1 Prince Rupert to San Francisco – DC Submarine Cable



Option:	1
Miles:	1525
Capital Cost:	$6.4 B
Capacity:	3200 MW
US$/MWh:	$22.65
Peak Losses:	15%

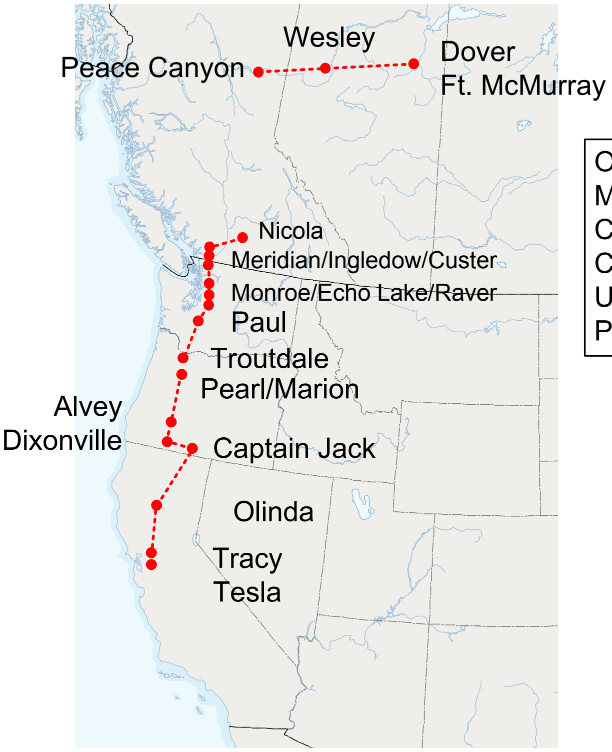
Fig 5b: Option 2 A and B Vancouver Island to Northern California AC - DC

Option:	2A	2B
Miles:	761	747
Capital Cost:	$2.2 B	$2.6 B
Capacity:	1500 MW	1600 MW
US$/MWh:	$16.58	$1814
Peak Losses:	18%	14%

Option:	2A'
Miles:	578
Capital Cost:	$0.9 B
Capacity:	1500 MW
US$/MWh:	$6.48
Peak Losses:	14%

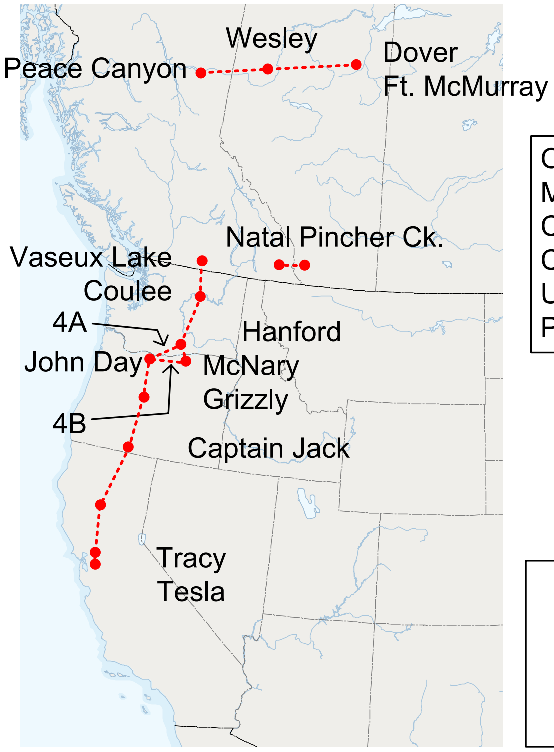
AC	┄┄┄
AC Station	●
HVDC	───
HVDC Converter	■

Fig 5c: Option 3 Northern Alberta to Northern California - AC West Side Route



Option:	3
Miles:	1497
Capital Cost:	$2.8 B
Capacity:	1500 MW
US$/MWh:	$20.98
Peak Losses:	29%

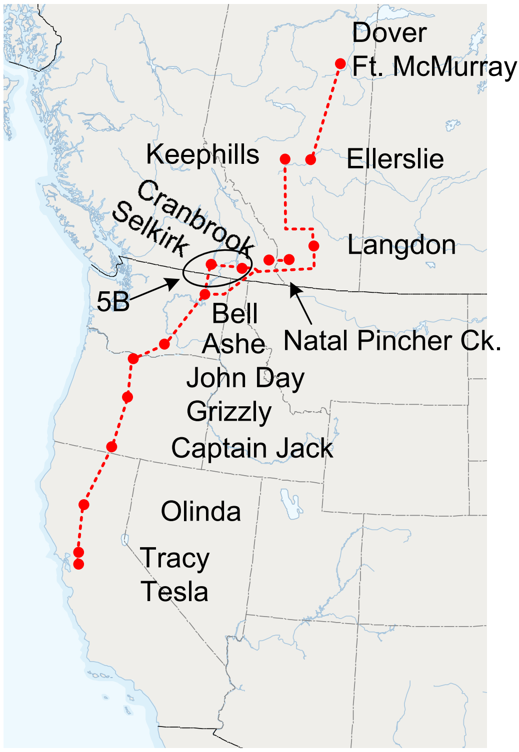
Fig 5d: Option 4 A & B Northern Alberta to Northern California - AC Central WA Route



Option:	4A	4B
Miles:	1307	1404
Capital Cost:	$2.3 B	$2.5 B
Capacity:	1500 MW	1500 MW
US$/MWh:	$17.17	$18.39
Peak Losses:	25%	25%

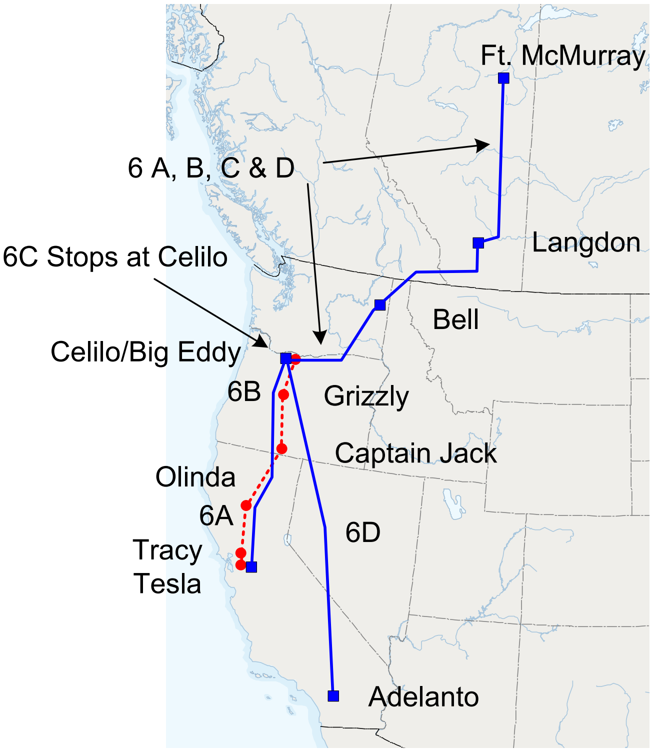
AC	┈┈┈
AC Station	●
HVDC	───
HVDC Converter	■

Fig 5e: Option 5 A and B Northern Alberta to Northern California - AC West Side Route



Option:	5A	5B
Miles:	1729	1801
Capital Cost:	$2.9 B	$3.0 B
Capacity:	1500 MW	1500 MW
US$/MWh:	$21.79	$22.51
Peak Losses:	26%	26%

Fig 5f: Option 6 A, B, C and D Northern Alberta to Celilo and California - DC/AC

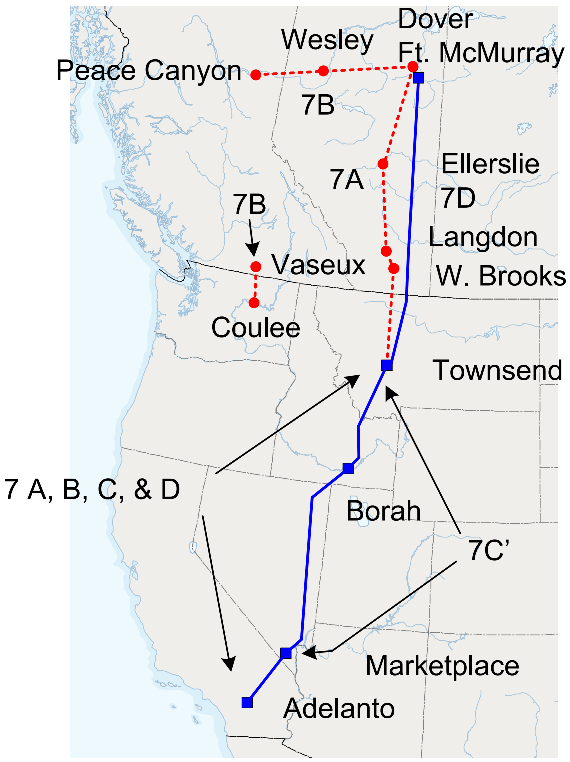


Option:	6A	6B
Miles:	1733	1732
Capital Cost:	$2.8B	$2.4 B
Capacity:	3000 MW	3000 MW
US$/MWh:	$10.45	$8.82
Peak Losses:	15%	12%

Option:	6C	6D
Miles:	1168	2014
Capital Cost:	$1.7 B	$2.7 B
Capacity:	3000 MW	3000 MW
US$/MWh:	$6.21	$10.21
Peak Losses:	11%	19% MW

AC	┈┈┈
AC Station	●
HVDC	───
HVDC Converter	■

Fig 5g: Option 7 A, B, C & D Northern AB to Southern California - AC/DC Inland Route

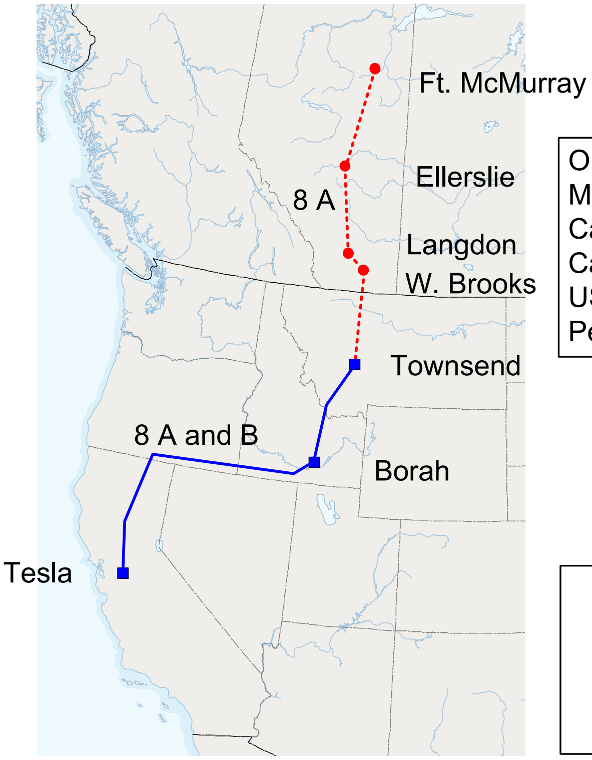


Option:	7A	7B
Miles:	1953	1574
Capital Cost:	$2.6 B	$2.3 B
Capacity:	3000 MW	3000 MW
US$/MWh:	$9.88	$8.50
Peak Losses:	16%	13%

Option:	7D
Miles:	1819
Capital Cost:	$2.5 B
Capacity:	3000 MW
US$/MWh:	$9.42
Peak Losses:	17%

Option:	7C	7C'
Miles:	1079	841
Capital Cost:	$1.6 B	$1.3 B
Capacity:	3000 MW	3000 MW
US$/MWh:	$5.84	$5.01
Peak Losses:	11%	9% MW

Fig 5h: Option 8 A and B Northern AB to Townsend to Northern California – AC/DC



Option:	8A	8B
Miles:	1960	1086
Capital Cost:	$2.7 B	$1.6 B
Capacity:	3000 MW	3000 MW
US$/MWh:	$9.99	$5.95
Peak Losses:	16%	11%

AC	┈┈┈
AC Station	●
HVDC	───
HVDC Converter	■

6. Transmission Analysis of CNC Transmission Options (Phase 2: Test options)

Both AC, DC and hybrid AC/DC options were considered in the study. Only the AC options were analyzed with power flow studies. Most AC portions of the hybrid AC/DC options were analyzed as portions of the AC only options. In addition, collector and distribution systems at the project ends were not analyzed.

6.1 Developing a Basecase

To confirm the reinforcements that would be required for each AC option, the study group developed a base case using the WECC Heavy Summer 2007 HS2A case and raising the flows on key paths as shown in Table 4.

WECC Path	Transfer Path	Path Rating	WECC Case Flows (MW)	CNC Bench Mark Case Flows (MW)
1	Alberta – British Columbia	East to West: 1000 MW West to East: 1200 MW	300 W>E	702 E>W
3	Northwest - Canada	North to South: 3150 MW South to North: 2000 MW	2757 N>S	3138 N>S
8	Montana - Northwest	East to West: 2200 MW West to East: 1350 MW	617 E>W	942 E>W
14	Idaho - Northwest	East to West: 2400 MW West to East: 1200 MW	439 W>E	418 W>E
26	Northern-Southern California	North to South: 4000 MW South to North: 3000 MW	2805 N>S	2748 N>S
65	Pacific DC Intertie	3100 MW bi-direction	3104 N>S	3104 N>S
66	COI	North to South: 4800 MW South to North: 3675 MW	4118 N>S	4535 N>S
73	North of John Day	OTC: 8400 MW	7263 N>S	7705 N>S
75	Midpoint – Summer Lake	East to West: 1500 MW West to East: 400 MW	52 E>W	99 E>W

Table 4: Major Path Flows for the WECC 2007 HS2A and CNC Benchmark Cases

6.2 Developing AC Option Cases

Cases were developed for the AC options by modifying the CNC Benchmark Case as follows:

- Adding 1500 MW generation at Fort McMurray, Alberta;
- Increasing the California load by 1500 MW (e.g. PG&E, SCE, SDG&E and LADWP areas were all scaled up).

The resulting impact on path flows is summarized in Table 5.

WECC Path	Transfer Path	CNC Bench Mark Case (MW)	Option 3	Option 4a	Option 4b	Option 5a	Option 5b
1	Alberta – British Columbia	702 E>W	2286	2273	2273	2369	2262
3	Northwest - Canada	3138 N>S	4625	4668	4668	4694	4670
8	Montana-Northwest	942 E>W	927	939	926	924	918
14	Idaho to Northwest	418 W>E	415	429	422	412	402
26	Northern-Southern California	2748 N>S	3558	3557	3553	3558	3562
65	Pacific DC Intertie	3104 N>S	3103	3103	3103	3103	3103
66	COI	4535 N>S	5987	5876	5873	5881	5877
73	North of John Day	7705 N>S	9189	9147	9028	9098	9089
75	Midpoint – Summer Lake	99 E>W	126	90	95	113	120

Table 5: Major Path Flows for Options 3, 4a, 4b, 5a and 5b Cases

6.3 Analyzing AC Option Cases

For Options 3, 4 and 5 transmission reinforcements and generation dropping Remedial Action Schemes (RAS)[33] were added to ensure that all lines remained within their thermal ratings for the All lines in service (N-0) and all N-1 scenarios with additional critical N-2 contingencies[34] reviewed as well, assuming 1500 MW of additional transfer. The purpose of the detailed AC analysis was to verify performance and identify any additional facilities necessary to achieve satisfactory performance for each of the options.

Each area was responsible for screening their part of the system. If unacceptable conditions resulted from these outages, the project was modified until acceptable performance was reached.

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[33] Remedial Action Schemes (RAS) refer to protection schemes that will result in specific actions being automatically taken following a specific contingency. An example of a common RAS in the Pacific Northwest is Generation Shedding; in this case Generators would be tripped to reduce flow on a path following the forced outage of one transmission line in that path.

[34] "N-1" refers to the forced outage of a single element of the transmission system. "N-2" refers to a single event that forces multiple elements of the transmission system out of service.

By region the following analysis was completed:

Alberta: AESO ran all N-1 230 kV and 500kV powerflow outages and performed selected reactive margin studies.

British Columbia: BCTC ran all 500kV N-1 powerflow outages and identified the required VAr supplying equipment at major transmission buses to provide acceptable voltage performance.

California: PG&E ran all Northern California 500 kV N-1contingencies and N-2 contingencies. The studies included both steady-state load flow and post-transient reactive margin on the double Palo Verde and Pacific DC Intertie contingencies.

Pacific Northwest: Powerex, BPA and PSE analyzed selected major 500 and 345-kV N-1 outages along with critical N-2 outages.

It is believed that the options modeled may provide additional capacity above the 1500 MW and/or a reduction of RAS from what is used in the existing system. While the additional capacity was not quantified at this time, this should be fully explored in any future studies.

6.4 Preliminary Analysis of DC Option Cases

From a load flow perspective the DC options look much like the addition of a load at the source end and a generating source at the load end. The information provided by a load flow analysis similar to the AC studies would not provide any significant insights. Therefore, load flow analysis of these options was not carried out. Those options that are taken forward to the next level of study will need to under go detailed interconnection and system dynamic studies.

6.5 Preliminary Analysis of AC/DC Hybrid Option Cases

Several AC/DC hybrid options were proposed, although they were not all studied with Power Flow cases. Two Sea Breeze RTS projects were modeled with power flow for some AC portions of the hybrid projects. In British Columbia, the AC portions of Sea Breeze RTS projects were not studied by the group and reinforcements were suggested based on the engineering judgment. Elsewhere, AC reinforcements that were found to be required are essentially the same as proposed for the AC Options where the proposed path flow becomes common to other AC options. The DC portion of the options is defined in the transmission options descriptions in Appendix 2..

6.6 RAS Assumptions

The intent of setting rules for the use of RAS for the new transmission options is to make an equitable comparison of alternatives. The intent of the study is to develop transmission options to increase capacity of the system, not just add RAS to the existing system.

AC Options

- RAS additions will meet the WECC/NERC criteria
- The goal of this study is to limit new RAS. RAS comparable to existing levels can be used on new lines to minimize the facilities needed to meet the capacity target.
- Judgment will then be used to optimize RAS use with the new transmission construction.

This will be done by:

- No new RAS added to new lines initially. If outage performance is inadequate, new RAS comparable to the existing level of RAS can be used for the new line.
- Extra capacity or a reduction in existing RAS is probably possible but will only be flagged for future study at this time, i.e. in rating studies.

DC Options

- Monopole – AC picks up for single pole loss, study other pole ramp and/or equivalent RAS if performance is inadequate. Extra capacity or a reduction in existing RAS is probably possible but will only be flagged for future study at this time, i.e. in rating studies.
- Bipole – RAS trip whatever loading is necessary

7. Costing the Transmission Options (Phase 3)

Having established the transmission reinforcements that would be required for each option, the group proceeded to estimate the costs of each. Table 6 below summarizes the capital costs for each option.

7.1 Cost Estimate Development

In developing cost estimates, it became apparent that these costs, especially line costs, will vary by region. These regional variations are discussed below. All estimates are P50 estimates[35] and denominated in 2005 US dollars.

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[35] “P50 estimates” refers to there being an equal probability that the actual costs will be higher or lower than the estimate.

Option	Canada to US Northwest		Canada to California		Montana to California		Montana to Las Vegas	
	Public	Merchant	Public	Merchant	Public	Merchant	Public	Merchant
1				$6,430				
2a' and 2a		$860		$2,210				
2b		$870		$2,580				
3	$1,450		$2,790					
4a	$1,120		$2,290					
4b	$1,280		$2,450					
5a	$1,740		$2,900					
5b	$1,830		$3,000					
6a	$1,830	$1,580	$3,020	$2,780				
6b	$1,820	$1,580	$3,000	$2,390				
6c	$1,900	$1,650						
6d	$1,900	$1,650	$3,500	$2,720				
7a			$3,380	$2,640				
7b			$3,040	$2,300				
7c and 7c'					$2,310	$1,570	$1,900	$1,340
7d			$3,360	$2,520				
8a			$3,300	$2,710				
8b					$2,230	$1,630		

Table 6a: Capital Cost Estimates for Transmission Options
(Values in millions of US Dollars at 2005 Price levels, including overheads and AFUDC[36])

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[36] **AFUDC**: Allowance for Funds Used During Construction.

Option	Canada to US Northwest		Canada to California		Montana to California		Montana to Las Vegas	
	Public	Merchant	Public	Merchant	Public	Merchant	Public	Merchant
1				$22.64				
2a' and 2a		$8.81		$16.60				
2b		$8.91		$18.17				
3	$10.89		$20.96					
4a	$8.41		$17.20					
4b	$9.62		$18.40					
5a	$13.07		$21.78					
5b	$13.75		$22.54					
6a	$6.87	$5.93	$11.34	$10.44				
6b	$6.84	$5.93	$11.27	$8.98				
6c	$7.14	$6.20						
6d	$7.14	$6.20	$13.15	$10.22				
7a			$12.69	$9.92				
7b			$11.42	$8.64				
7c and 7c'					$8.68	$5.90	$7.14	$5.03
7d			$12.62	$9.46				
8a			$12.39	$10.18				
8b					$8.38	$6.12		

Table 6b: Wheeling Cost Estimates for Transmission Options
(Values in $/MWh at 2005 Price levels assuming 100% Capacity Factor)

Pacific Northwest/California costs

Recent projects (Coulee-Bell in Northeast Washington and the Path 15 project in California), were compared. Both of these projects used existing ROW through mostly rural areas and had very similar direct cost of about $900,000 per mile. It was felt that a 10% escalation from these actual costs would be appropriate. The Coulee-Bell line used three 1.3 inch conductors in a bundle and this was used as a standard AC design. It was assumed that new ROW would be required for all line construction ($100,000 per mile). Overheads and interest during construction would be at about 30%.

With land, overhead and interest during construction, the total cost would be about $1.4 million per mile. This would be the low end of cost for the new line since some of the new construction proposed in this report would be in more urban areas, especially for the west side options. It was decided that a portion of the new line construction could be twice this cost (based on recent experience in the Puget Sound area with the Kangley-Echo Lake project). Using a 75/25% split between rural and urban, $1.8 million per mile was assumed for the western option, Option 3. For the eastern options, the Washington and Oregon portions of Options 4 and 5, a 90/10% split was assumed that resulted in an overall estimate $1.6 million per mile. All California AC options followed the existing Captain Jack-Olinda-Tesla line route and were assumed to be the higher cost ($1.8 million per mile).

In its analysis of upgrades for the Path 18 Open Season, Northwestern Energy has estimated 500 kV line cost at $1.6 million per mile which gives additional validity to the above estimates.

BC Costs

Line costs for the portion of the options in British Columbia were based on recent estimates in that area for a new line between the Interior and the Lower Mainland. BCTC estimates that their line construction costs could be about $1.4 million per mile for interior purposes, which includes allowances for rural and Crown land. The urban portions of the options in the Lower Mainland, Vancouver Island and Southern Interior will utilize more private land, and as a result the cost of building lines in the urban areas is assumed to be $1.6 million per mile.

Alberta Costs

Alberta estimates that their line cost for the portions of the options in Alberta would be $875 million per mile.

DC line costs

It was assumed that the cost of DC line would be slightly lower than AC lines. The amount of conductor on these lines would be similar to the AC (eight conductors per line for DC vs. nine conductors for AC although the conductors for DC are expected to be larger than AC). There are fewer insulators on a two-pole DC line. With these differences, DC line costs in the NW and California were assumed to be $100,000/mile less than an AC circuit for utilities.

Merchant DC lines costs

The Merchant Transmission Companies felt they could provide the new transmission at a lower cost than the utilities. They have indicated that they could build 500-kV DC transmission for $891,000 per mile including all land and financing costs. As it is unknown who would build and own the proposed lines, both merchant and utility numbers were shown in the cost estimates for DC line options.

DC Cable Costs

Costs of underwater DC cables were provided by Seabreeze. They expect that 500-kV underwater cables will cost $1.6 million per mile installed. Cables needed for the lower voltage HVDC Light technology[37] (150-kV) were expected to cost $1.7 million per mile.

The following is a summary of the line cost assumptions for this study.

	US Options	Options in BC	Options in AB	Merchant Cost
500-kV line Cost	$1.8 M/mile I-5 $1.6 M/mile east of the cascades	$1.4 M/mile rural $1.6 M/mile urban	$875,000/mile	N/A
500-kV DC line	$1.7 M/mile west $1.5 M/mile east of the cascades	N/A	$929,000/mile	$949,000/mile - $1,050,000/mile
500-kV DC cable (1200 MW- bipoles)	N/A	N/A	N/A	1.6 million/mile
500-kV DC cable (1600 MW - bipoles)	N/A	N/A	N/A	2.0 million/mile
500-kV DC cable (3200 MW - bipoles)	N/A	N/A	N/A	4.0 million/mile
150-kV DC cable (1100 MW - bipoles)	N/A	N/A	N/A	1.7 million/mile

Table 7: Line Cost Assumptions

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[37] Cable data is available from an ABB document called "Its Time to Connect". It is available at:

http://library.abb.com/GLOBAL/SCOT/scot221.nsf/VerityDisplay/38E7A4D4ABFD675DC1257125002AF7E8/$File/It%20is%20time%20to%20connect%20rev%202%20febr%202006%20web.pdf.

Costs of other needed facilities were also based on recent experience of the participating utilities and were assumed to be the same for all areas.

Facility	Cost	Notes
500-kV Breaker	$2.3 million/breaker	Per breaker in breaker and half
500-kV Series Cap - New	$13 million	Roughly 3000 A, 28 ohms
500-kV Series Cap - Upgrade	$10 million	
500-kV Shunt Cap	$5.2 million	400 MVAR
200 MVAR SVC	$18 million	$90/kvar
500-kV Reactor	$7.5 million	180 MVAR
500/230-kV Transformer	$13 million	1300 MVA with breakers
230-kV line cost	$0.65 million/mile	Steel, 1.3 inch conductor
230-kV breaker	$1.0 million/breaker	Per breaker
550 MW DC terminal	$53.4 million	150-kV HVDC Light
1000 MW DC terminal	$105 million	500-kV, traditional technology
1600 MW DC terminal	$152 million	500-kV, traditional technology
3000 MW DC terminal	$285 million	500-kV, traditional technology
RAS Scheme	$5 million plus $1 million per line	
Communications	$30 million for whole project	

Table 8: Station Cost Assumptions

8. Loss Analysis

Whenever electric energy is transported over transmission lines electrical losses are generated as a result of current flowing though a resistance. Losses in the lines, transformers and converter stations are an important factor in choosing the most appropriate configuration and determining the economics of any particular proposal.

Evaluating the losses on an integrated system and the impact of any particular development is complex. Given that this study is a first cut look at a wide variety of alternatives, the team decided to take a simple indicative look at losses for the various alternatives.

For each alternative the indicative value of losses was calculated from the generator to the assumed load delivery point. Energy delivery points include the Columbia River area, Tesla in the San Francisco area and Adelanto in the Los Angeles area. In the cost of delivered energy evaluation the value of losses was calculated using the production cost of the generation supplying the energy.

The approach used was to assume that all of the energy for each of the alternatives flows over the new facility added to carry the energy. Where no new lines are added due to latent capacity of the existing system an assessment of incremental losses on the existing system was made. Where new flows generally added to existing flows, a charge was added to the alternative. Where new flows generally reduced existing flows, a credit was applied. For example, for alternatives that used the latent capacity of the Peace Canyon to Nicola system, the incremental losses were assessed and added to the total losses of the alternative. For alternatives that reduced the flow on the Coulee to Colstrip system, a loss credit was assessed that effectively reduced the losses of the alternative.

Table 9 below summarizes the magnitude of losses for each alternative over peak system loading conditions and the energy losses taking into account the energy source capacity factor.

Opt	Description	Peak Losses (MW)	% of Peak	Energy Losses (Avg MW)	% of generated Energy
1	Prince Rupert (PR) to San Francisco (SF) – DC Submarine Cable PR to Dunsmuir DC 2400 MW at 75% capacity factor (CF) Dunsmuir to SF DC 3200 MW at 79% CF	475	14.8%	260	10.9%
2A	Vancouver Island (VI) to Northern California (NCA) AC Northern VI to Paul AC/DC 1100 MW at 75% CF Paul to Tesla AC 1500 MW at 79% CF	272	18.2%	162	13.7%
2A’	Vancouver Island (VI) to Oregon AC Northern VI to Troutdale AC/DC 1100 MW at 75%	151	13.8%	85	10.3%
2B	Vancouver Island (VI) to Northern California (NCA) DC Northern VI to Paul AC/DC 1100 MW at 75% CF Paul to Allston AC 1500 MW at 80% CF Allston to SF DC 1500 MW at 80% CF	218	13.6%	132	10.4%
3	Northern Alberta (NAB) to NCA AC - Westside Route 50/50% flow split between Northern BC and AB 95% CF Dover to Peace Canyon to Nicola 750 MW • using available capacity from PC to Nicola Dover to Nicola using existing capacity 750 MW • existing AB – assumed 500 MW load on a 500 kV line plus 750 MW new (based on 1500 MW at Ft. McMurray)	431	28.7%	390	27.4%
4A	NAB to NCA - AC Central Washington Route Same loss calculation as 3 except • Counter flow credit for 750 MW between Nicola and Vaseux Lake Losses for 4B are similar (based on 1500 MW at Ft. McMurray)	374	24.9%	339	23.8%
5A	NAB to NCA AC East Side Route Dover to Tesla 1500 MW at 95% CF except Reverse flow credit from Ellerslie to Keephills Losses for 5B are similar	385	25.6%	347	24.4%

Opt	Description	Peak Losses (MW)	% of Peak	Energy Losses (Avg MW)	% of generated Energy
6A	NAB to NCA Fort McMurray to Celilo 3000 MW DC 95% CF Celilo to Tesla 1500 MW AC	442	14.8%	402	14.1%
6B	NAB to NCA Fort McMurray to Celilo 3000 MW DC 95% CF Celilo to Tesla 1500 MW DC at 95% CF	360	12.0%	326	11.4%
6C	NAB to Celilo Fort McMurray to Celilo 3000 MW DC 95% CF	342	11.4%	311	10.9%
6D	NAB to NCA Fort McMurray to Adelanto 3000 MW DC 95% CF	558	18.6%	504	17.7%
7A	NAB to Townsend to SCA Dover to Townsend 1500 MW AC 90% CF Townsend to Adelanto 3000 MW DC 90% CF	483	16.1%	410	15.3%
7B	NAB to Coulee via BC and Townsend to SCA Dover to Coulee 1500 MW AC flow same as 4A Townsend to Adelanto 3000 MW DC 90% CF	392	13.1%	331	12.4%
7C	Montana to Southern CA DC Townsend to Adelanto 3000 MW DC at 84% CF	318	10.6%	230	9.1%
7C’	Montana to Las Vegas Townsend to Marketplace 3000 MW DC: 84% CF	257	8.6%	187	7.4%
7D	Northern Alberta to Southern California 3000 MW DC at 95% CF	508	16.9%	460	16.1%
8A	NAB to NCA Dover to Townsend 1500 MW AC at 90% CF Townsend to Tesla 3000 MW DC at 90% CF	485	16.2%	411	15.3%
8B	Montana to NCA Townsend to Tesla 3000 MW DC at 84% CF	320	10.7%	232	9.2%

Table 9: New System Losses

Table 10 summarizes the physical parameters that were used to calculate the losses.

	Conductor	Resistance	Losses
500 kV AC lines	3 – Falcon 1590 kcmil ACSR	0.0122 ohms/1000 ft. per conductor at 40 °C	0.094 MW/mile with 1000 MW load at 90% power factor
230 kV AC lines	1 – Falcon	0.0122 ohms/1000 ft. at 40 °C	0.22 MW/mile with 400 MW load at 90% power factor
500/230 kV transformations	N/A		ignored
+/- 500 kV DC lines merchant	4 – Falcon	0.0122 ohms/1000 ft. per conductor	0.115 MW/mile at 2000 MW load
+/- 500 kV submarine DC cable 600 MW	1600 mm^2	0.0113 ohms/km at 20 deg C	0.0326 MW/km at 1200 MW bi-pole load
+/- 500 kV submarine DC cable 800 MW	1800 mm^2	0.0098 ohms/km at 20 deg C	0.0502 MW/km at 1600 MW bi-pole load
Converter stations	N/A	N/A	0.7% per 2000 MW terminal

Table 10: Physical Parameters for Loss Calculations

The formula used to adjust losses for distance and load is:

Peak Losses = Distance x Losses per mile x $(\text{load/standard load})^2$

Energy Losses = Distance x Losses per mile x $(\text{load/standard load})^2$ x capacity factor^2

Where the standard load is 1000 MW for a 500 kV AC system and 2000 MW for a 500 kV DC overhead system.

9. Transmission Option Analysis and Cost of Delivered Energy Workbook (Phase 5)

Having identified the transmission reinforcements for the different options and estimated their costs, the last phase of the study involved developing a workbook for calculating the delivered cost of energy. The workbook is available for use by any interested party, including load serving entities and resource developers who want to explore possible development scenarios. The workbook can be downloaded from the NTAC web site using: (***www.nwpp.org/ntac/pdf/CNC_Options_Analysis_Tool_-_2006.xls***). A Users' Manual for the Transmission Options Analysis and Cost of Delivered Energy workbook is provided in Appendix 3.

The workbook records detailed cost estimates for each transmission option. These are set out on estimating sheets that are specific to each option. The workbook also contains an economic analysis for each option. A transmission option may serve one more generating resource or combinations of generating resources[38]. The economic analysis sheet calculates first year costs and levelized real costs for each resource in US dollars and $US per MWh. Costs of generating systems, transmission systems and losses show separately.

A "Console" sheet at the start of the workbook allows the unit costs of transmission system components and other variables to be changed for all options simultaneously. It is informative, for example, to change the natural gas price on the console and see how the rankings of the resources change.

A "Gen Costs" sheet provides generating cost data from published sources that can be referenced in the economic analysis sheets. This sheet also acts as a console. Changing a heat rate or unit cost on this sheet will change values in the economic analysis sheets that refer to it.

Several summary sheets in different formats allow comparison of the options and the resources within the options. Analysts can add other generating resources to the transmission options or change the parameters on the console. Sample costs of delivered energy for each transmission option for a medium gas forecast are shown in Figure 6[39].

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[38] A significant portion of the cost of delivered energy stems from the assumed generation resource. Each generation resource has several variables, such as cost for installed capacity, availability, unit size and project life, readers are encouraged to varying or investigate what the appropriate installed generation costs would be for their particular scenario of interest.

[39] The Gas Price Forecasts used in the CNC study are consistent with the forecasts used in the SSG-WI (Seams Steering Group – Western Interconnect) 2015 IRP-RPS Reference Case, Production Cost Modeling Results that can be found at http://ssgwi.com in the working groups, planning section.

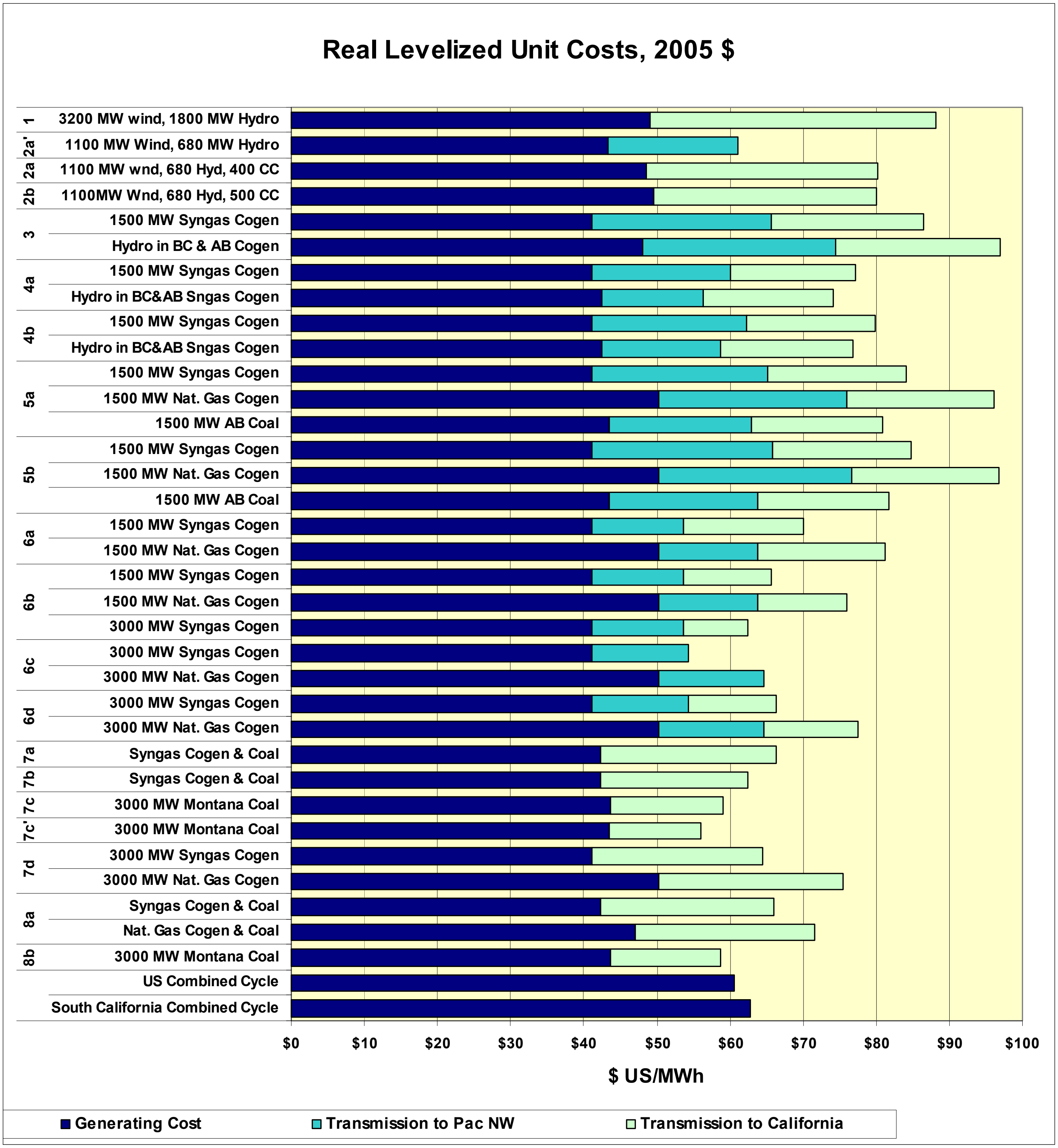

Figure 6: Examples of Costs of Delivered Energy
(Assuming Medium Gas Forecast of $7/MMBTU at HH)

10. Results and Conclusions

NTAC established the Canada-Northwest-California (CNC) Study Group because there are vast undeveloped generation resources in Canada and the Pacific Northwest that would require capacity increases in the transmission system in order to deliver energy to west coast load centers. The CNC group developed transmission options that could integrate these remote resources by increasing the North to South transfer capability between 1500 MW – 3200 MW. The costs for the Canada to California projects range from $2.2 billion to $6.4 billion and are primarily a function of distance.

A primary benefit of these transmission projects is providing access to economic resources and this study estimated that it is possible to deliver resources from western Canada to the Pacific Northwest at costs ranging from approximately $50/MWh to $75/MWh[40]. Similarly the study estimated that the delivered cost of energy to California for remote Canadian resources ranges from $60/MWh to $100/MWh. Other benefits of developing some of the transmission alternatives include energy diversity (including renewable energy source), geographic diversity and economic development in resource areas. A further benefit of several of the transmission options is the potential reductions in RAS requirements.

This study does not endorse any particular transmission option, but rather provides information to all interested parties. Before any particular option proceeds, further analysis will be required, including detailed power system analysis.

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[40] Costs represent levelized life cycle costs in $2005.

11. Next Steps

Feedback from the readers of this report will be important to help define the scope of any subsequent studies. Written comments in particular are encouraged and can be sent to the CNC study Co-chairs: mjlandauer@bpa.gov or gdeshazo@caiso.com. Alternatively, comments can be forewarded to all members of NTAC by sending an e-mail to: NTAC@nwpp.org.

WECC is initiating its Transmission Expansion Planning Policy Committee in order to perform economic review of transmission expansion projects, including production cost modeling. The CNC group believes that subregional planning groups need to provide WECC information on possible regional infrastructure projects. Through this report the CNC has developed several feasible transmission scenarios and recommends that TEPPC analyze the economic benefits of these projects shortly after the Committee begins its work.

If a proponent wants to move forward with any particular option at this stage, they would need to follow the WECC Regional Planning Project Review process under WECC's Planning Coordination Committee[41].

If it is determined that a second CNC study group be convened to perform more detailed analysis of selected options it is recommended that the next stages include the following:

1) Refine the selected options: in this phase the group would work together to refine each selected option based on the results of the economic analysis.

2) Complete Analysis of selected options, including:
    a) Powerflow and Transient Stability studies for DC and Hybrid options, including the receiving end transmission;
    b) Transient Stability for AC options

3) Determine additional benefits:
    a) Quantify additional North-to-South Transfer Capability
    b) Quantify South to North Transfer Capability
    c) Quantify the RAS reduction

4) Compare the selected options against common measures, including:
    a) Reliability improvements,
    b) NWPCC Portfolio Risk Analysis;
    c) Congestion improvements;
    d) Capital cost;
    e) Economic gains;
    f) Loss impacts

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[41] Details of WECC's Regional Planning Project Review process can be found at: http://www.wecc.biz/documents/library/procedures/planning/Overview_Policies_Procedures_RegionalPlanning_ProjectReview_ProjectRating_ProgressReports_07-05.pdf.

Appendix 1 – CNC Study Participants

Name	**Company**
Elroy Switlishoff	Fortis BC
Bob Chow	AESO - Alberta Electric System Operator
Trevor Cline	AESO - Alberta Electric System Operator
Ed Groce	AVA - Avista
Scott Waples	AVA - Avista
Amir Amjadi	BCTC – BC Transmission Corporation
Anita Ha	BPA – Bonneville Power Adminstration (TBL)
Marv Landauer	BPA – Bonneville Power Adminstration (TBL)
Mike Kreipe	BPA – Bonneville Power Adminstration (TBL)
Rebecca Berdahl	BPA – Bonneville Power Adminstration (PBL)
Gary DeShazo	CAISO – California Independent System Operator
Janice Zewe	CAISO – California Independent System Operator
Scott Buehn	Chelan PUD
Ron Zeilstra	Columbia Power Corp
Julia Souder	DOE-DC – Department of Energy
John Montgomery	ENE
Chris Joy	ENMAX
Barry Flynn	Flynn Assoc
John Leland	NWE – Northwest Energy
Julie Reichle	NWE – Northwest Energy
Jeff King	NWPCC – Northwest Power Planning and Coordination Council
Wally Gibson	NWPCC – Northwest Power Planning and Coordination Council
Dana Reedy	NWPP – Northwest Power Pool
Stefan Brown	OPUC
Phil Carver	OR-DOE
Don Johnson	PAC - Pacifcorp
Jamie Austin	PAC - Pacifcorp
Jeff Miller	PAC - Pacifcorp

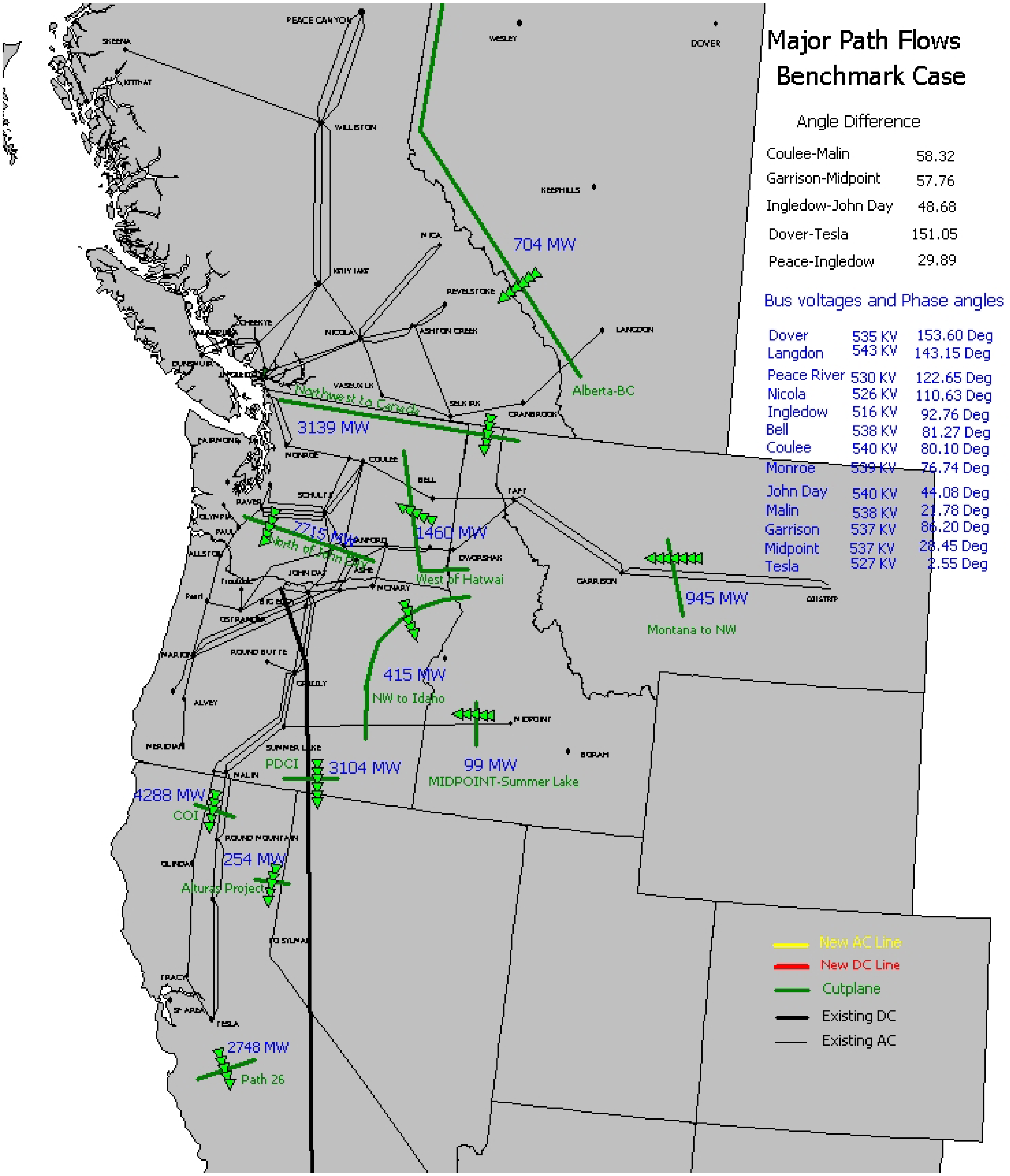
Kurt Granat	PAC - Pacifcorp
Sherman Chen	PG&E – Pacific Gas & Electric
Jerry Thale	PGE-PS – Portland General Electric
Jim Eden	PGE-PS – Portland General Electric
Gordon Dobson-Mack	Powerex
Mahta Boozari	Powerex
Nancy Baker	PPC
Chris Reese	PSE – Puget Sound Energy
John Phillips	PSE – Puget Sound Energy
Sal Avalos	PSE – Puget Sound Energy
Natalie McIntire	RNP
Jim Polvi	SBP-RTS – Sea Breeze Pacific Regional Transmission System
E. John Tompkins	SBP-RTS – Sea Breeze Pacific Regional Transmission System
Rod Lenfest	SBP-RTS – Sea Breeze Pacific Regional Transmission System
Tony Duggleby	Katabatic Power Corp.
Franklin Lu	SCL – Seattle City Light
Dilip Mehendra	SMUD
John Martinsen	SNPD – Snohomish PUD
Monte Meredith	TANC
Bill Hosie	TC-NLT – TransCanada: Northern Lights Transmission
Cliff Perigo	TC-NLT – TransCanada: Northern Lights Transmission
Stew Jenkinson	TC-NLT – TransCanada: Northern Lights Transmission
Margaret Kirk	TPWR
Roger Hamilton	WWW – West Wind Wires

Appendix 2 – Transmission Options: Table & Maps

Transmission Option	Transfer Capacity	Resource Scenario
OPTION 1: Prince Rupert to San Francisco		
Option 1: DC Submarine cable from Prince Rupert to Vancouver Island to San Francisco 230 kV Kitimat – Minette – Skeena – Prince Rupert. Keogh – Gold River – Dunsmuir 2 x 230 kV lines 500 kV DC submarine cable (SC) Prince Rupert (RUP) – Port Hardy; 500 kV DC overhead (OH) Port Hardy – Dunsmuir (DMR) – Port Alberni; 500 kV DC submarine Port Alberni - San Francisco Bay area. Converters: Prince Rupert 2400 MW, Dunsmuir 3200 MW, San Francisco West Bay 1600 MW and East Bay 1600 MW, optional tap in NW.	2400 MW Rupert – Dunsmuir 3200 MW Dunsmuir – San Francisco	Coastal Wind and Hydro in North West BC, Wind on Northern Vancouver Island.
OPTION 2: Vancouver Island to Northern California using Westside route		
Option 2A: DC submarine cable from Vancouver Island to Olympic Peninsula with 500 kV AC line to Northern California using westside route Keogh – Gold River – Dunsmuir 2 x 230 kV lines; Dunsmuir – Sahtlam – Pike Lake conversion to 500 kV Pike – Fairmount DC cable, Fairmount – Shelton – Olympia 230 line; Paul – Troutdale; Pearl – Marion - Alvey – Dixonville – Meridian -Captain Jack – Olinda – Tracy – Tesla 500 kV lines Converters: Pike 2 X 550 MW, Fairmont and Port Angeles 550 MW Option 2A' terminates in the PNW at Troutdale.	1100 MW to Paul 1500 MW Paul to Tesla	Wind on Northern Vancouver Island, BC Resources, South Seattle CTs. (1000 MW at Fairmont and 500 MW at Paul assumed for studies)
Option 2B: DC submarine cable from Vancouver Island to Olympic Peninsula with 500 kV AC line to Northern California using Westside route Keogh – Gold River – Dunsmuir 2 x 230 kV lines; Dunsmuir – Sahtlam – Pike Lake conversion to 500 kV Pike – Fairmount DC cable, Fairmount – Shelton – Olympia 230 kV; Paul – Longview – Troutdale 500 kV; Longview – Allston 500 kV; Allston to San Francisco Bay area Converters: Pike 2 X 550 MW, Fairmont and Port Angeles 550 MW; Alston 1600 MW, San Francisco West Bay 800 MW and East Bay 800 MW (Newark D, Newark	1100 MW to Paul 1600 MW to San Francisco Bay	Wind on Northern Vancouver Island, BC Resources, South Seattle CTs. (1000 MW at Fairmont and 600 MW at Paul assumed for studies)

Transmission Option	**Transfer Capacity**	**Resource Scenario**
OPTION 3: Northern Alberta to Northern California using westside route		
Option 3: 500-kV AC line from Northern Alberta/BC to Northern California using Westside route (Dover-Wesley-Peace Canyon; Nicola-Meridian - Ingledow – Custer - Monroe – Echo Lake; Raver – Paul – Troutdale: Pearl – Marion - Alvey – Dixonville - Meridian - Captain Jack – Olinda – Tracy - Tesla)	1500 MW	Fort McMurray Cogen, Alberta Coal. Hydro or Wind in North East BC, Coastal Wind and Hydro in North West BC, Wind on Northern Vancouver Island, and NW WA Cogen. (1500 MW at Fort McMurray assumed for studies),
OPTION 4: Northern Alberta to Northern California using central Washington route		
Option 4A: 500-kV AC line from Northern Alberta/BC to Northern California using mid-WA/OR route (Dover-Wesley-Peace Canyon; Meridian – Ingledow; Vasuex Lake - Coulee - Hanford - John Day – Grizzly - Captain Jack - Olinda – Tracy - Tesla)	1500 MW	Hydro in South Interior BC, Southern Alberta Wind, Central WA Wind. (1500 MW at Fort McMurray assumed for studies)
Option 4B: 500-kV AC line from Northern Alberta/BC to Northern California using mid-WA route via McNary (Dover-Wesley-Peace Canyon; Meridian – Ingledow; Vasuex Lake - Coulee - Hanford – McNary - John Day – Grizzly - Captain Jack - Olinda – Tracy - Tesla)	1500 MW	Hydro in South Interior BC, Southern Alberta Wind, Central WA Wind. (1500 MW at Fort McMurray assumed for studies)
OPTION 5: Northern Alberta to Northern California using eastside route		
Option 5A: 500-kV AC line from Northern Alberta to Northern California using eastside route (Dover – Ellerslie; Meridian – Ingledow; Keephills – Langdon - Bell - Ashe - John Day – Grizzly - Captain Jack - Olinda – Tracy – Tesla)	1500 MW	Fort McMurray Cogen, Northern Alberta Hydro, Lake Wabamun Coal, Southern Alberta Wind, Central WA Wind, SE BC Resources. (1500 MW at Fort McMurray assumed for studies)
Option 5B: 500- kV AC line from Northern Alberta to Northern California using eastside route via Selkirk (Dover – Ellerslie; Meridian – Ingledow; Keephills - Langdon – Cranbrook – Selkirk - Bell - Ashe – John Day – Grizzly - Captain Jack - Olinda – Tracy – Tesla)	1500 MW	Fort McMurray Cogen, Northern Alberta Hydro, Lake Wabamun Coal, Southern Alberta Wind, Central WA Wind, SE BC Resources. (1500 MW at Fort McMurray assumed for studies)
OPTION 6: Northern Alberta – Celilo- California		
Option 6A: DC line from Northern Alberta to Celilo, AC line from Celilo to Northern California (Fort McMurray – Milo – Bell – Ashe - Celilo DC line, Big Eddy - Grizzly - Captain Jack - Olinda – Tracy – Tesla 500-kV AC line)	3000 MW from FM to Celilo, 1500 MW from Celilo to Tesla.	Fort McMurray Cogen, Northern Alberta Hydro, Lake Wabamun Coal, Southern Alberta Wind. (3000 MW at Fort McMurray assumed for studies)
Option 6B: DC line from Northern Alberta to Northern California via Celilo (Fort McMurray – Milo –Pincher Creek - Bell (optional DC terminal) – Ashe - Celilo (optional DC terminal) – Capt Jack – Olinda - Tesla DC line)	3000 MW from FM to Celilo, 1500 MW from Celilo to Tesla.	Fort McMurray Cogen, Northern Alberta Hydro, Lake Wabamun Coal, Southern Alberta Wind. (3000 MW at Fort McMurray assumed for studies)
Option 6C: DC line from Northern Alberta to Celilo (Fort McMurray – Milo – Pincher Creek - Bell (optional DC terminal) – Ashe – Celilo DC line)	3000 MW from FM to Celilo.	Fort McMurray Cogen, Northern Alberta Hydro, Lake Wabamun Coal, Southern Alberta Wind. (3000 MW at Fort McMurray assumed for studies)
Option 6D: DC line from Northern Alberta to Celilo and LA (Fort McMurray – Milo – Pincher Creek - Bell (optional DC terminal) – Ashe - Celilo (optional DC terminal) – Adelanto DC line).	3000 MW from FM to Adelanto.	Fort McMurray Cogen, Northern Alberta Hydro, Lake Wabamun Coal, Southern Alberta Wind. (3000 MW at Fort McMurray assumed for studies)

Transmission Option	**Transfer Capacity**	**Resource Scenario**
OPTION 7: Northern Alberta – Townsend – Southern California		
Option 7A: AC line from Northern Alberta to Townsend, DC line from Townsend to Southern California via Borah and SWIP (Dover - Ellerslie – Langdon - Westbrooks – Townsend 500-kV AC line; Townsend - Borah (Optional DC term) - Marketplace (Optional DC term) - Adelanto DC line).	1500 from Alb/BC, 1500 from Mt, 3000 MW DC south of Townsend	Fort McMurray Cogen, Northern Alberta Hydro, Lake Wabamun Coal, Southern Alberta Wind, Montana, Wyoming and Idaho generation. (1500 MW at Fort McMurray and 1500 MW at Townsend assumed for studies)
Option 7B: AC line from Northern Alberta to Coulee via BC, DC line from Townsend to Southern California via Borah and SWIP (Dover-Wesley-Peace Canyon, Meridian – Ingledow; Vasuex Lake -Coulee, Townsend - Borah (Optional DC term) - Marketplace (Optional DC term) - Adelanto.	1500 from Alb/BC, 1500 from Mt, 3000 MW DC south of Townsend	Fort McMurray Cogen, Northern Alberta Hydro, Lake Wabamun Coal, Southern Alberta Wind, Montana, Wyoming and Idaho generation. (1500 MW at Fort McMurray and 1500 MW at Townsend assumed for studies)
Option 7C: DC line Townsend to Southern California via Borah and SWIP (Townsend - Marketplace (Optional DC terminal) – Marketplace (Optional DC terminal) - Adelanto). Option 7C' terminates at Marketplace (Las Vegas)	3000 MW from Montana	Montana, Wyoming and Idaho generation (3000 MW at Townsend assumed for studies).
Option 7D: DC line from Northern Alberta to Southern California through Townsend, Borah and SWIP corridor – (Fort McMurray – Genesee – Langdon - Westbrooks – Townsend (Optional DC terminal) - Borah – SWIP corridor – Marketplace (Optional DC terminal) – Adelanto).	3000 MW	Fort McMurray Cogen, Northern Alberta Hydro, Lake Wabamun Coal, Southern Alberta Wind, Montana, Wyoming and Idaho generation. (3000 MW at Fort McMurray assumed for studies)
OPTION 8: Northern Alberta – Townsend – Northern California		
Option 8A: AC line from Northern Alberta to Townsend, DC line from Townsend to Northern California via Borah and SWIP – (Dover – Ellerslie – Langdon - Westbrooks - Townsend 500-kV AC line, Townsend - Midpoint – Captain Jack – Olinda - Tracy – Tesla DC line)	3000 MW	Fort McMurray Cogen, Northern Alberta Hydro, Lake Wabamun Coal, Southern Alberta Wind, Montana, Wyoming and Idaho generation. (1500 MW at Fort McMurray and 1500 MW at Townsend assumed for studies)
Option 8B: DC line from Townsend to Northern California via Borah (Townsend - Borah (Optional DC term) – Midpoint – Captain Jack – Olinda - Tracy – Tesla DC line)	3000 MW	Montana, Wyoming and Idaho generation (3000 MW at Townsend assumed for studies)



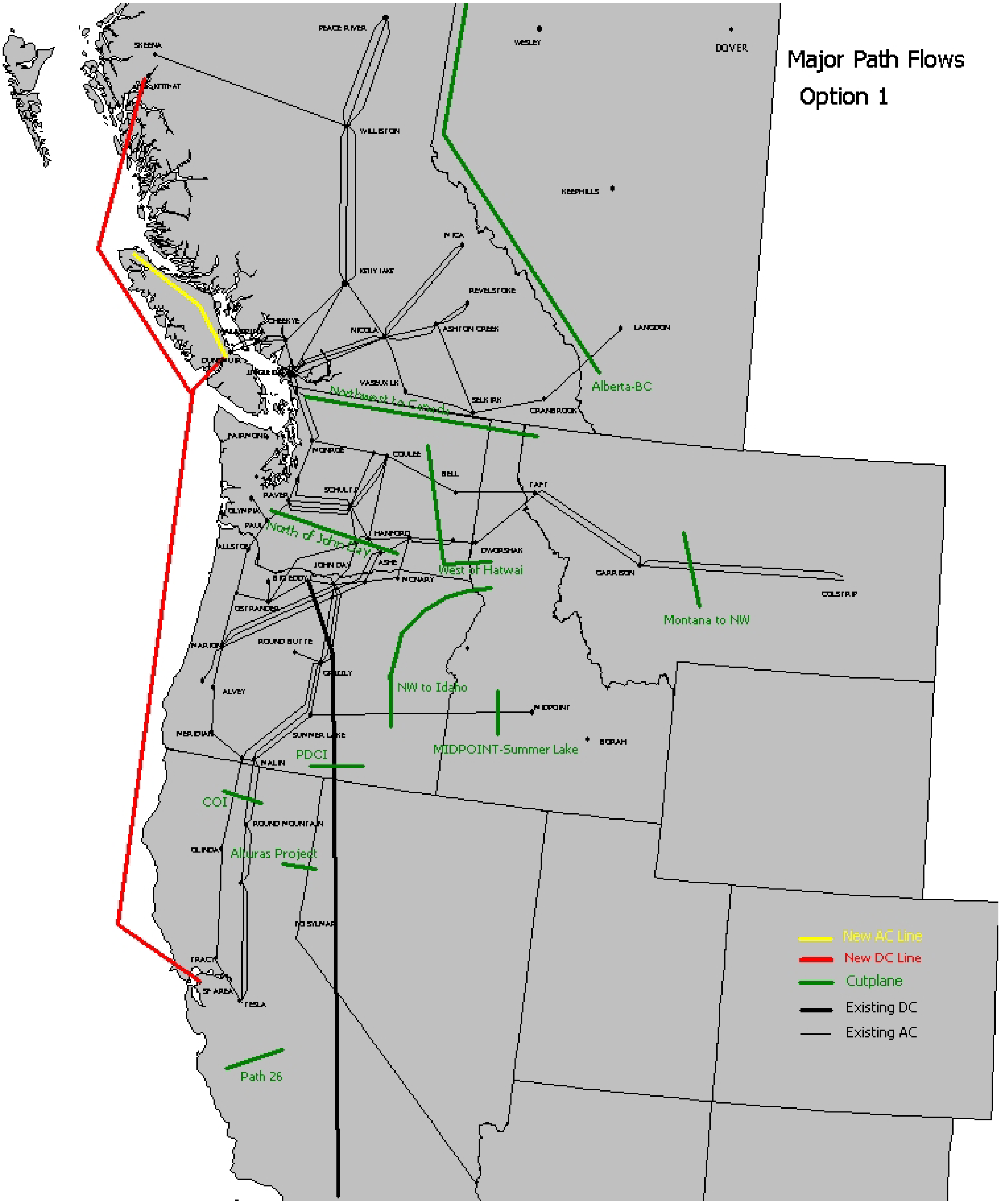
Major Path Flows
Benchmark Case

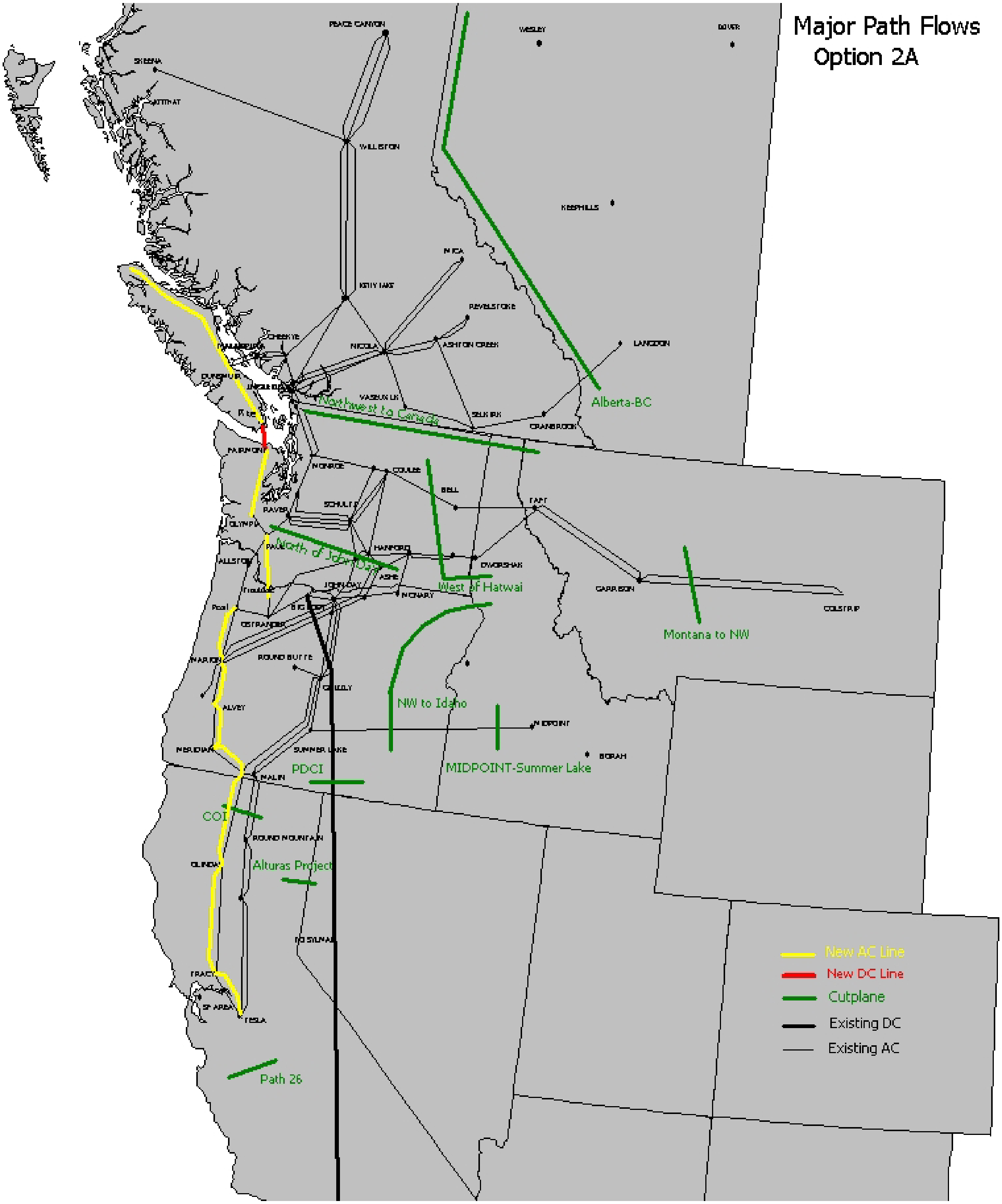
Angle Difference

Coulee-Malin	58.32
Garrison-Midpoint	57.76
Ingledow-John Day	48.68
Dover-Tesla	151.05
Peace-Ingledow	29.89

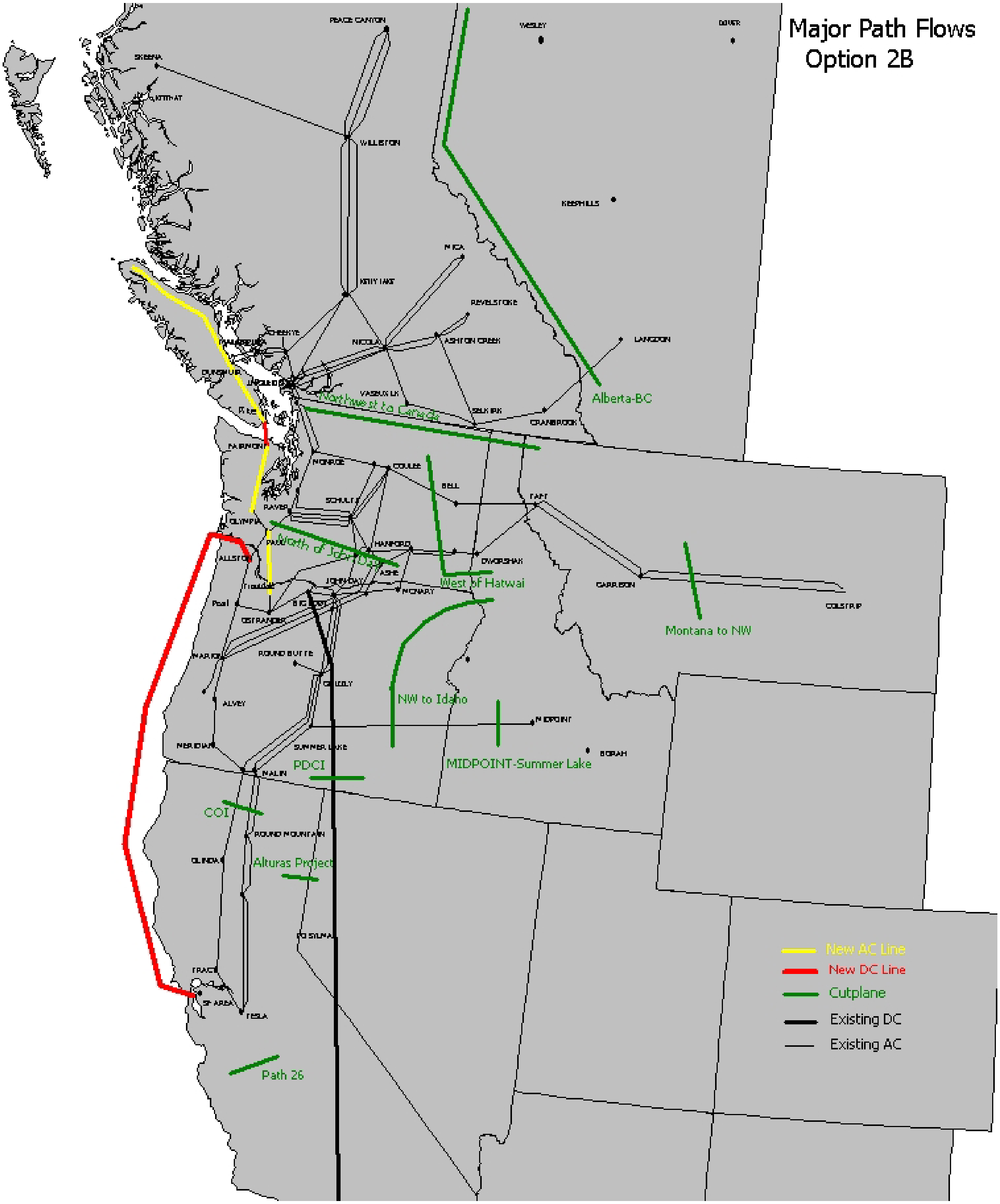
Bus voltages and Phase angles

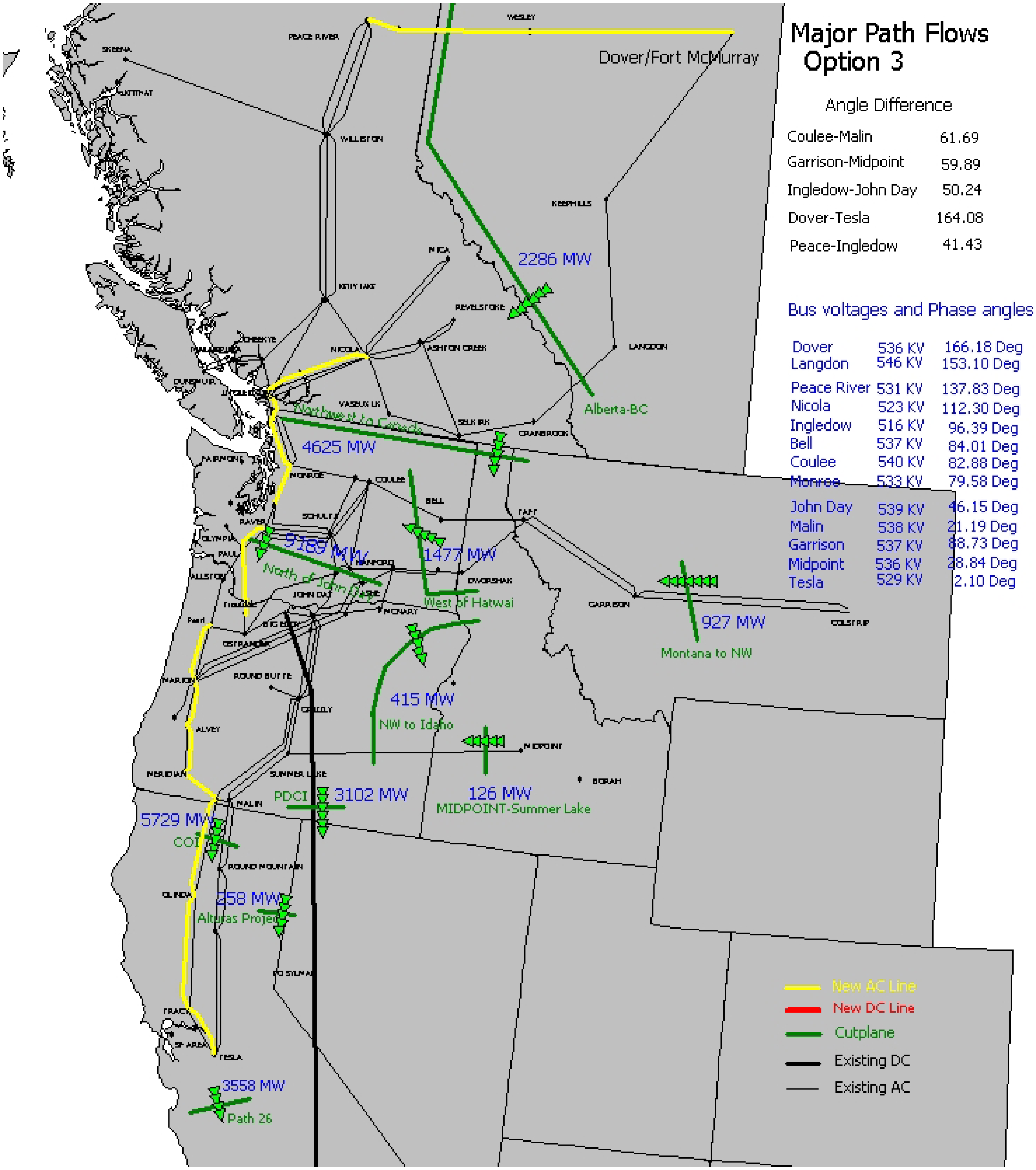
Dover	535 KV	153.60 Deg
Langdon	543 KV	143.15 Deg
Peace River	530 KV	122.65 Deg
Nicola	526 KV	110.63 Deg
Ingledow	516 KV	92.76 Deg
Bell	538 KV	81.27 Deg
Coulee	540 KV	80.10 Deg
Monroe	539 KV	76.74 Deg
John Day	540 KV	44.08 Deg
Malin	538 KV	21.78 Deg
Garrison	537 KV	86.20 Deg
Midpoint	537 KV	28.45 Deg
Tesla	527 KV	2.55 Deg


Major Path Flows
Option 1
PEACE RIVER
WESLEY
DOVER
SKEENA
KITIMAT
WILLISTON
KEEPHILLS
MICA
KELLY LAKE
REVELSTOKE
CHEEKYE
NICOLA
ASHTON CREEK
LANGDON
DUNSMUIR
INGLEDOW
VASEUX LK
Alberta-BC
Northwest to Canada
SELKIRK
CRANBROOK
FAIRMONT
MONROE
COULEE
BELL
TAFT
SCHULTZ
RAVER
OLYMPIA
PAUL
North of John Day
HANFORD
DWORSHAK
ALLSTON
JOHN DAY
ASHE
West of Hatwai
GARRISON
BIG EDDY
MCNARY
COLSTRIP
OSTRANDER
Montana to NW
MARION
ROUND BUTTE
GRIZZLY
ALVEY
NW to Idaho
MIDPOINT
MERIDIAN
SUMMER LAKE
BORAH
MIDPOINT-Summer Lake
PDCI
MALIN
COI
ROUND MOUNTAIN
OLINDA
Alturas Project
TO SYLMAR
TRACY
SF AREA
TESLA
Path 26
New AC Line
New DC Line
Cutplane
Existing DC
Existing AC



Major Path Flows
Option 2A

Major Path Flows
Option 2B
PEACE CANYON
WESLEY
DOVER
SKEENA
KITIMAT
WILLISTON
KEEPHILLS
MICA
KELLY LAKE
REVELSTOKE
CHEEKYE
NICOLA
ASHTON CREEK
LANGDON
DUNSMUIR
VASEUX LK
Northwest to Canada
SELKIRK
CRANBROOK
Alberta-BC
FAIRMONT
MONROE
COULEE
BELL
TAFT
SCHULTZ
RAVER
OLYMPIA
PAUL
North of John Day
HANFORD
DWORSHAK
ALLSTON
Troutdale
JOHN DAY
ASHE
MCNARY
West of Hatwai
GARRISON
COLSTRIP
Pearl
BIG EDDY
OSTRANDER
Montana to NW
MARION
ROUND BUTTE
GRIZZLY
ALVEY
NW to Idaho
MIDPOINT
MERIDIAN
SUMMER LAKE
BORAH
MIDPOINT-Summer Lake
PDCI
MALIN
COI
ROUND MOUNTAIN
OLINDA
Alturas Project
SYLMAR
TRACY
SF AREA
TESLA
Path 26
New AC Line
New DC Line
Cutplane
Existing DC
Existing AC



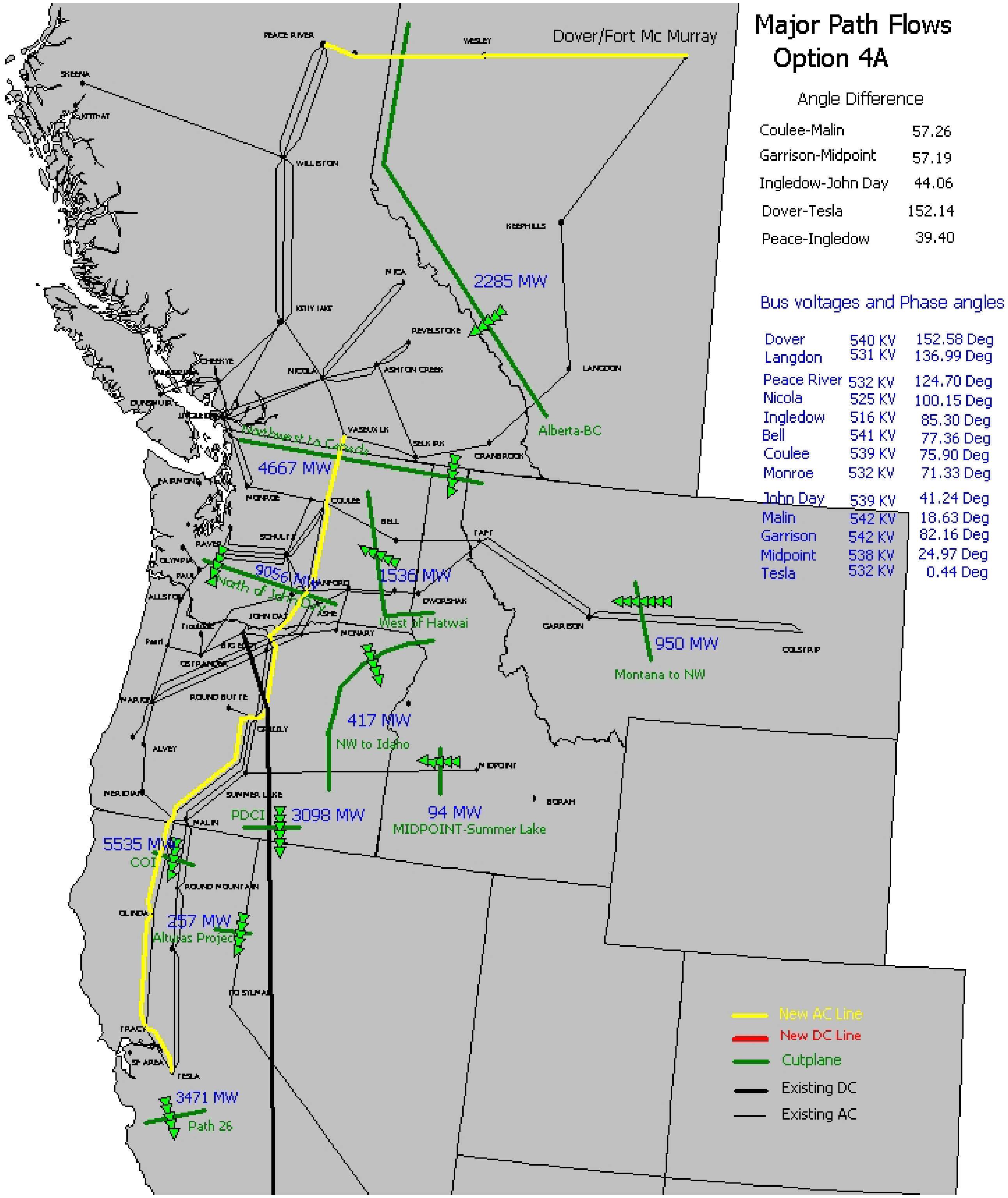
Major Path Flows
Option 3

Angle Difference

Coulee-Malin	61.69
Garrison-Midpoint	59.89
Ingledow-John Day	50.24
Dover-Tesla	164.08
Peace-Ingledow	41.43

Bus voltages and Phase angles

Dover	536 KV	166.18 Deg
Langdon	546 KV	153.10 Deg
Peace River	531 KV	137.83 Deg
Nicola	523 KV	112.30 Deg
Ingledow	516 KV	96.39 Deg
Bell	537 KV	84.01 Deg
Coulee	540 KV	82.88 Deg
Monroe	533 KV	79.58 Deg
John Day	539 KV	46.15 Deg
Malin	538 KV	21.19 Deg
Garrison	537 KV	88.73 Deg
Midpoint	536 KV	28.84 Deg
Tesla	529 KV	2.10 Deg



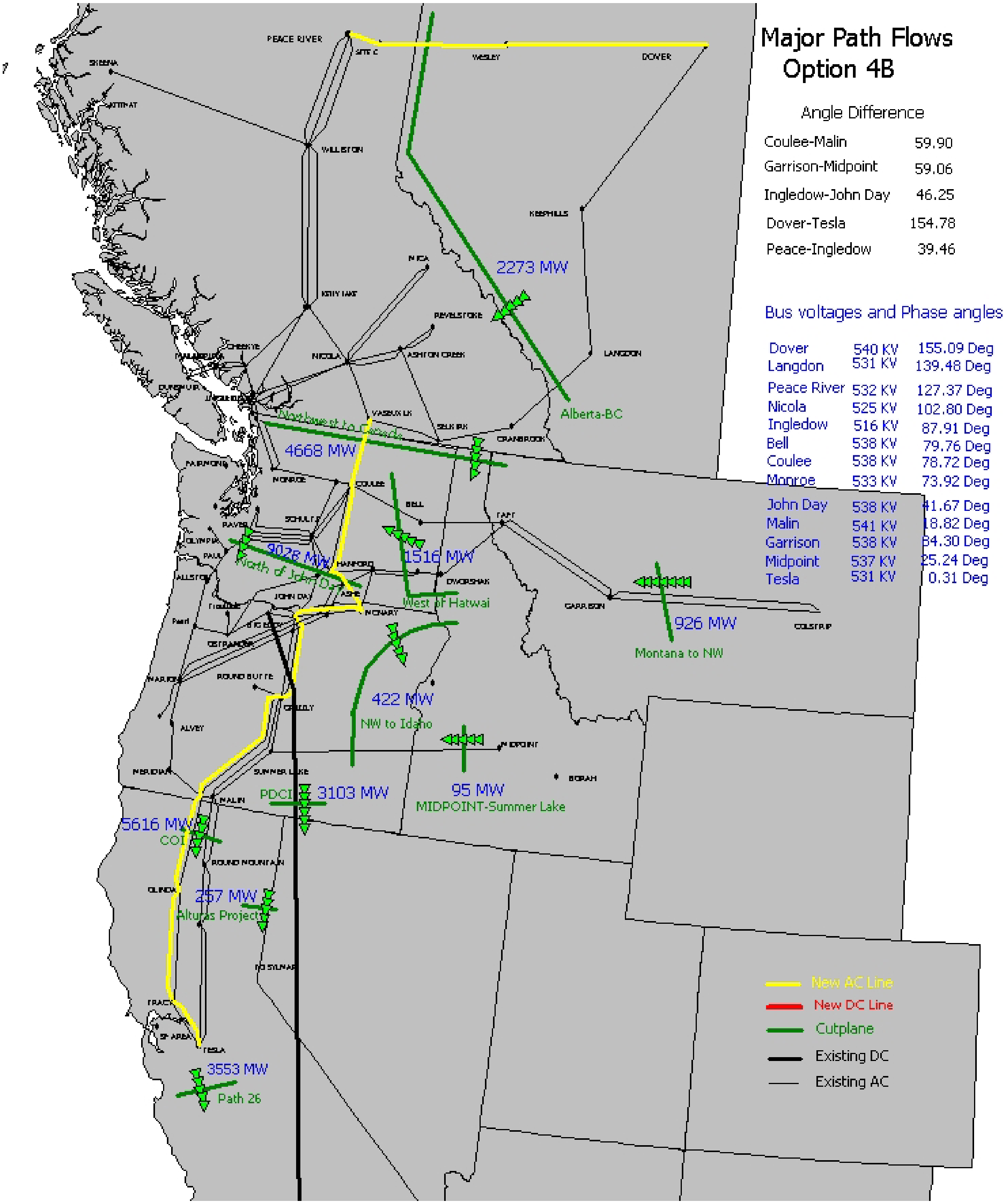
Major Path Flows Option 4A

Angle Difference

Coulee-Malin	57.26
Garrison-Midpoint	57.19
Ingledow-John Day	44.06
Dover-Tesla	152.14
Peace-Ingledow	39.40

Bus voltages and Phase angles

Dover	540 KV	152.58 Deg
Langdon	531 KV	136.99 Deg
Peace River	532 KV	124.70 Deg
Nicola	525 KV	100.15 Deg
Ingledow	516 KV	85.30 Deg
Bell	541 KV	77.36 Deg
Coulee	539 KV	75.90 Deg
Monroe	532 KV	71.33 Deg
John Day	539 KV	41.24 Deg
Malin	542 KV	18.63 Deg
Garrison	542 KV	82.16 Deg
Midpoint	538 KV	24.97 Deg
Tesla	532 KV	0.44 Deg



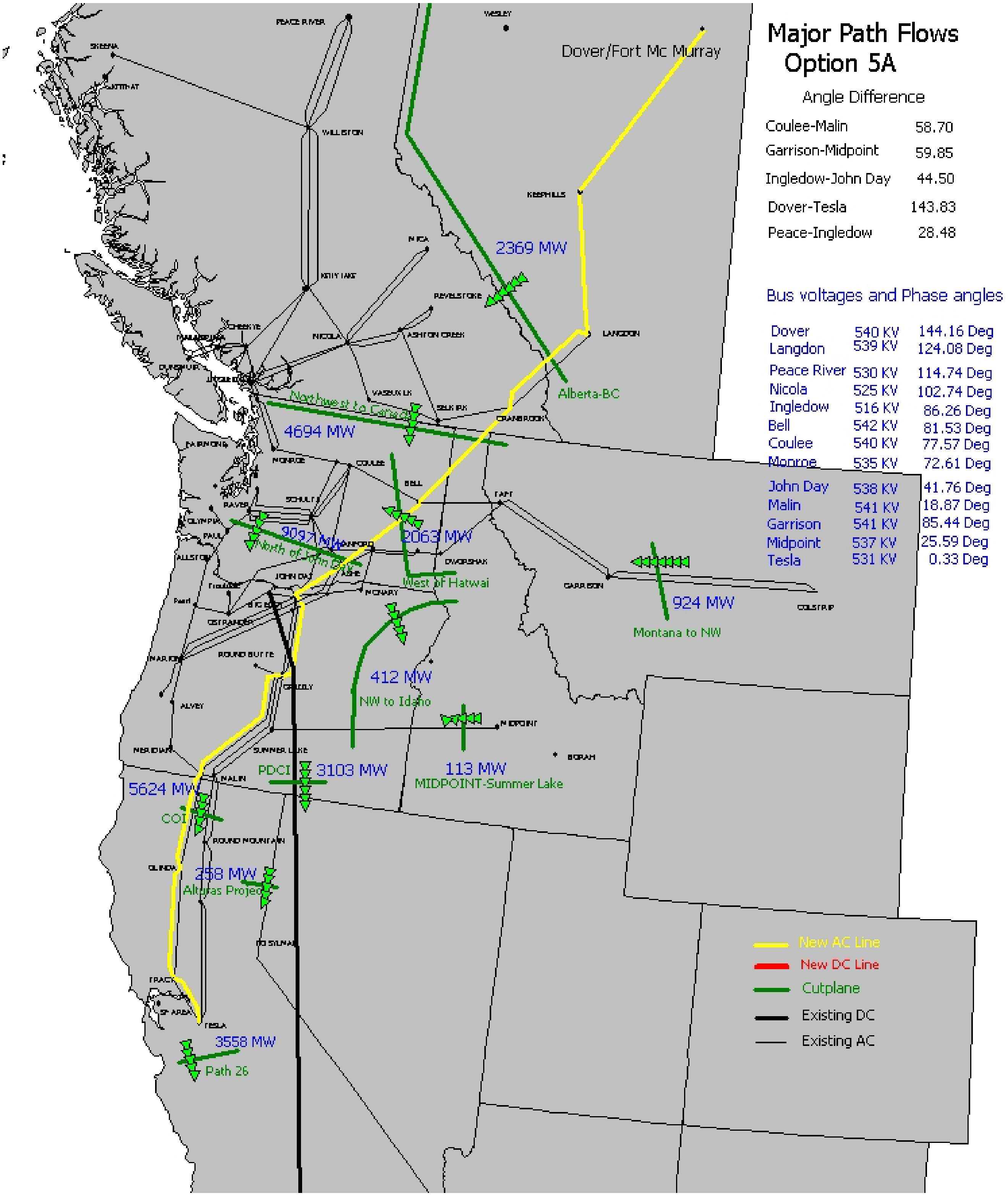
Major Path Flows Option 4B

Angle Difference

Coulee-Malin	59.90
Garrison-Midpoint	59.06
Ingledow-John Day	46.25
Dover-Tesla	154.78
Peace-Ingledow	39.46

Bus voltages and Phase angles

Dover	540 KV	155.09 Deg
Langdon	531 KV	139.48 Deg
Peace River	532 KV	127.37 Deg
Nicola	525 KV	102.80 Deg
Ingledow	516 KV	87.91 Deg
Bell	538 KV	79.76 Deg
Coulee	538 KV	78.72 Deg
Monroe	533 KV	73.92 Deg
John Day	538 KV	41.67 Deg
Malin	541 KV	18.82 Deg
Garrison	538 KV	84.30 Deg
Midpoint	537 KV	25.24 Deg
Tesla	531 KV	0.31 Deg



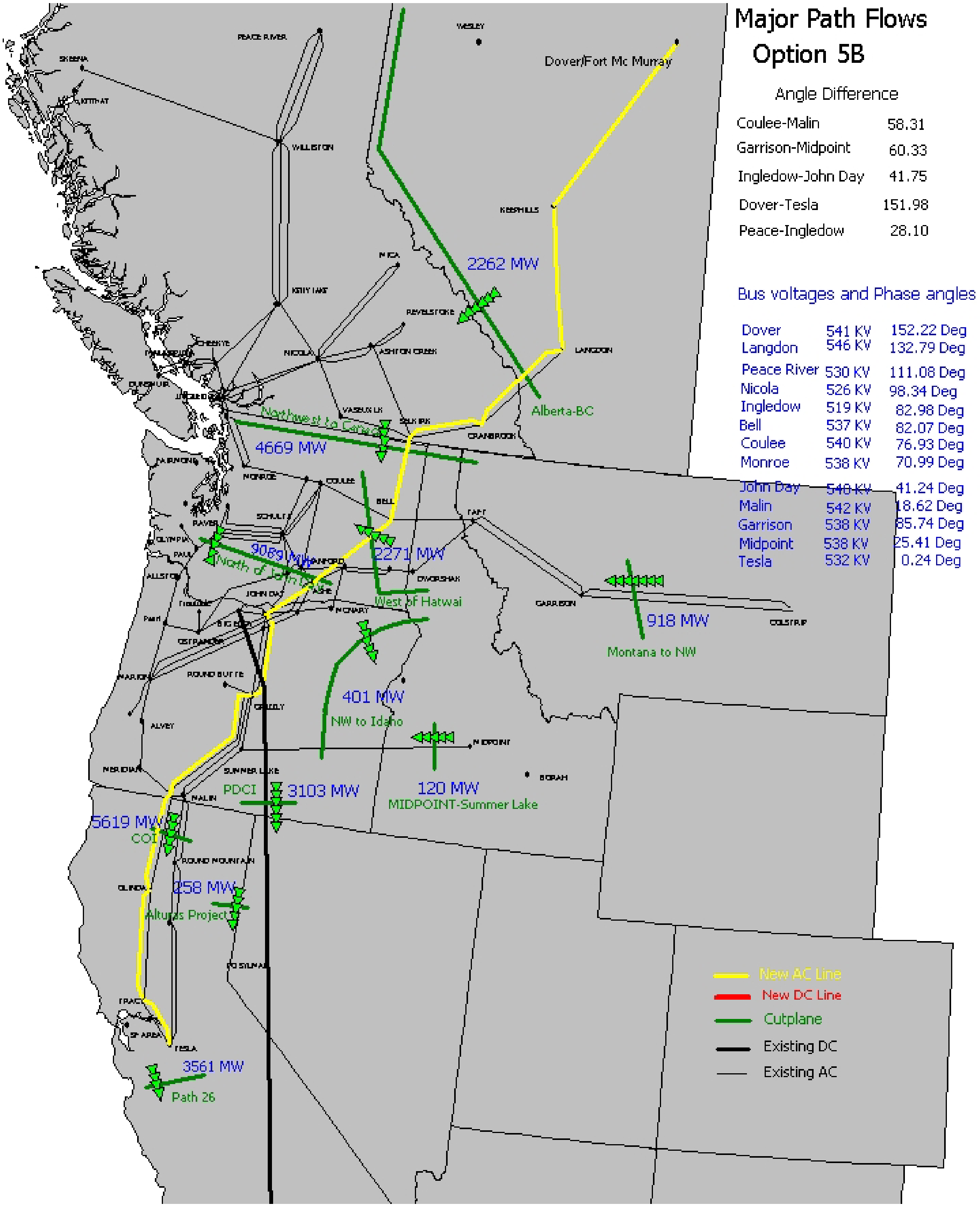
Major Path Flows
Option 5A

Angle Difference

Coulee-Malin	58.70
Garrison-Midpoint	59.85
Ingledow-John Day	44.50
Dover-Tesla	143.83
Peace-Ingledow	28.48

Bus voltages and Phase angles

Dover	540 KV	144.16 Deg
Langdon	539 KV	124.08 Deg
Peace River	530 KV	114.74 Deg
Nicola	525 KV	102.74 Deg
Ingledow	516 KV	86.26 Deg
Bell	542 KV	81.53 Deg
Coulee	540 KV	77.57 Deg
Monroe	535 KV	72.61 Deg
John Day	538 KV	41.76 Deg
Malin	541 KV	18.87 Deg
Garrison	541 KV	85.44 Deg
Midpoint	537 KV	25.59 Deg
Tesla	531 KV	0.33 Deg



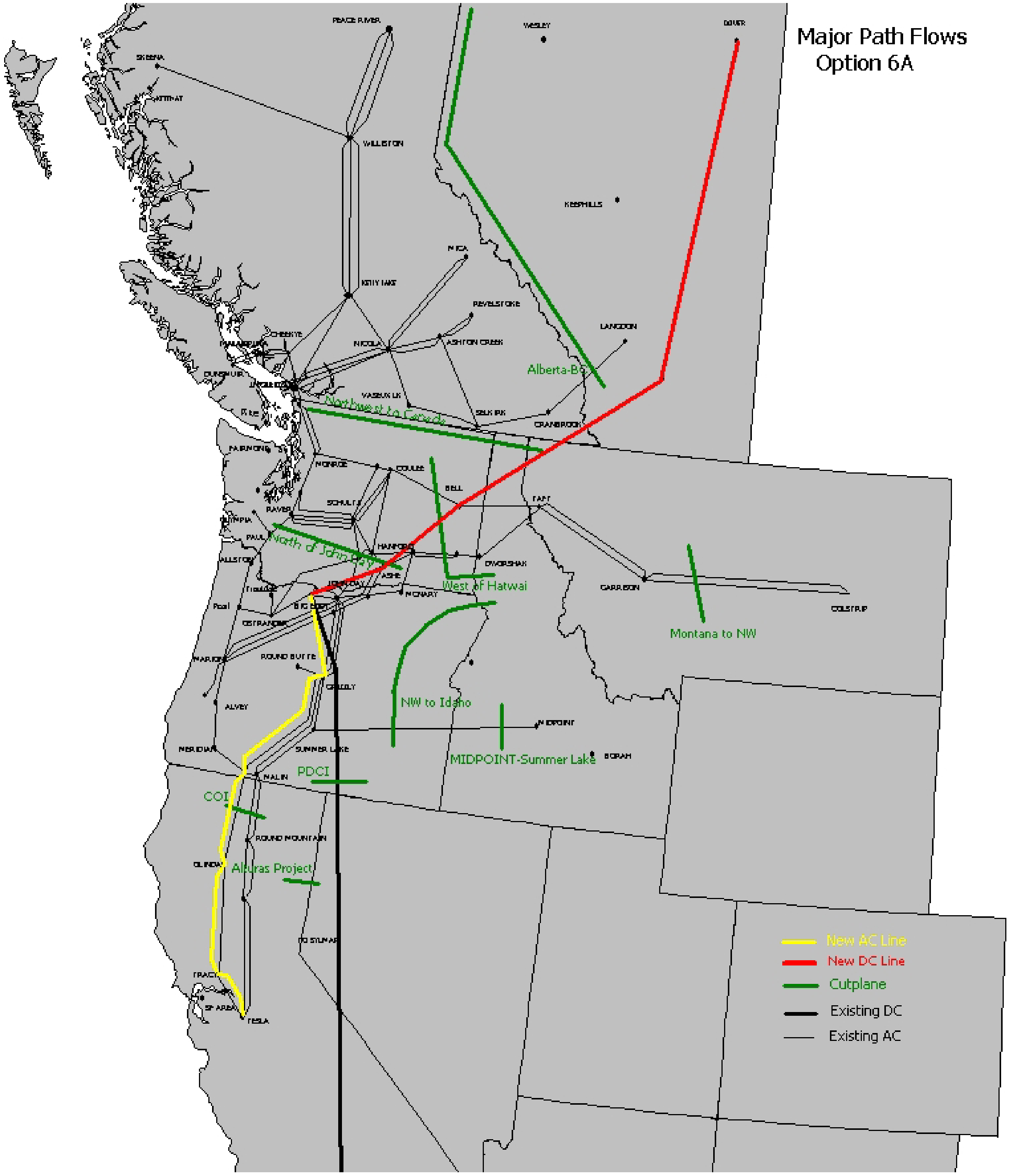
Major Path Flows
Option 5B

Angle Difference

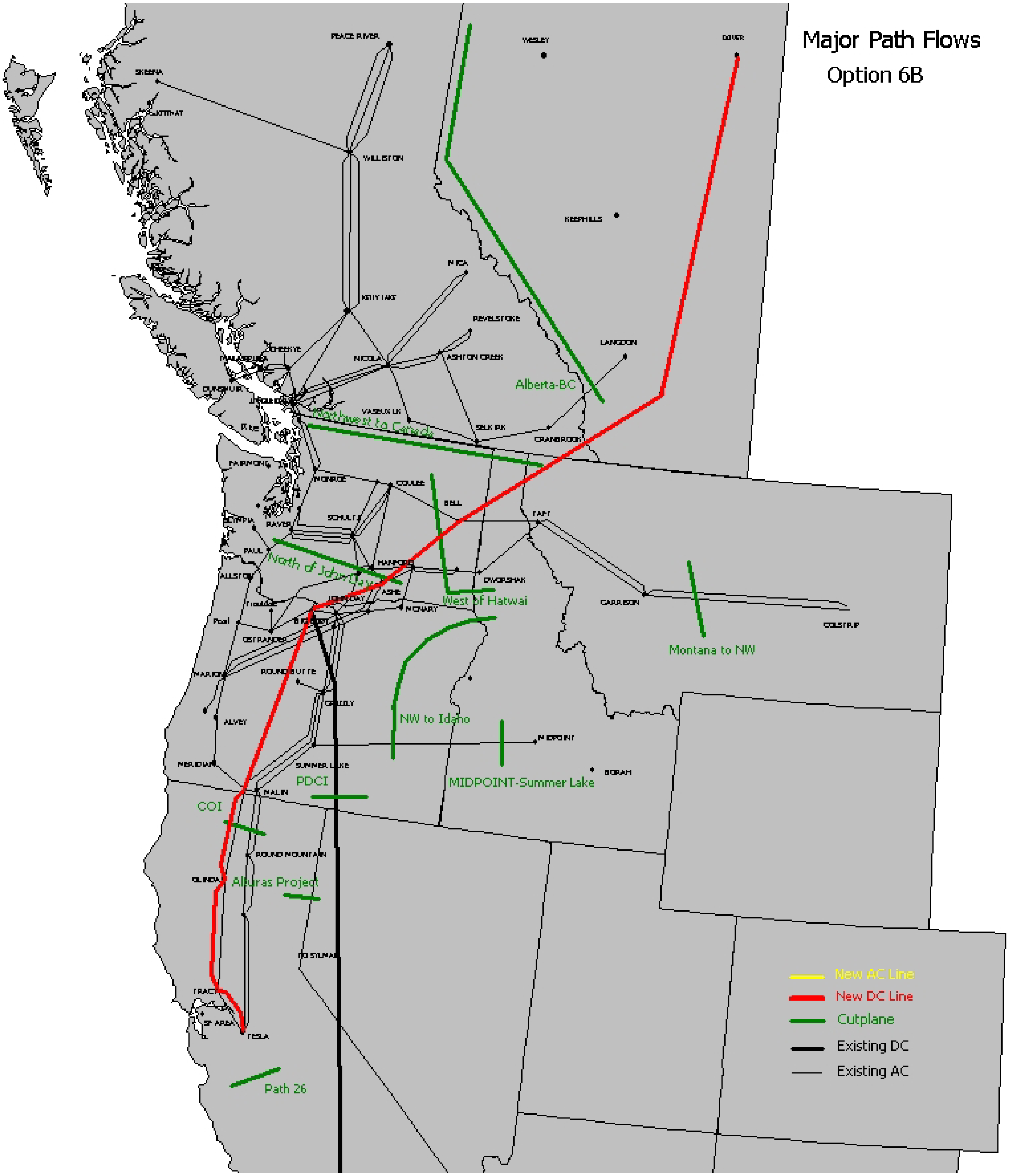
Coulee-Malin	58.31
Garrison-Midpoint	60.33
Ingledow-John Day	41.75
Dover-Tesla	151.98
Peace-Ingledow	28.10

Bus voltages and Phase angles

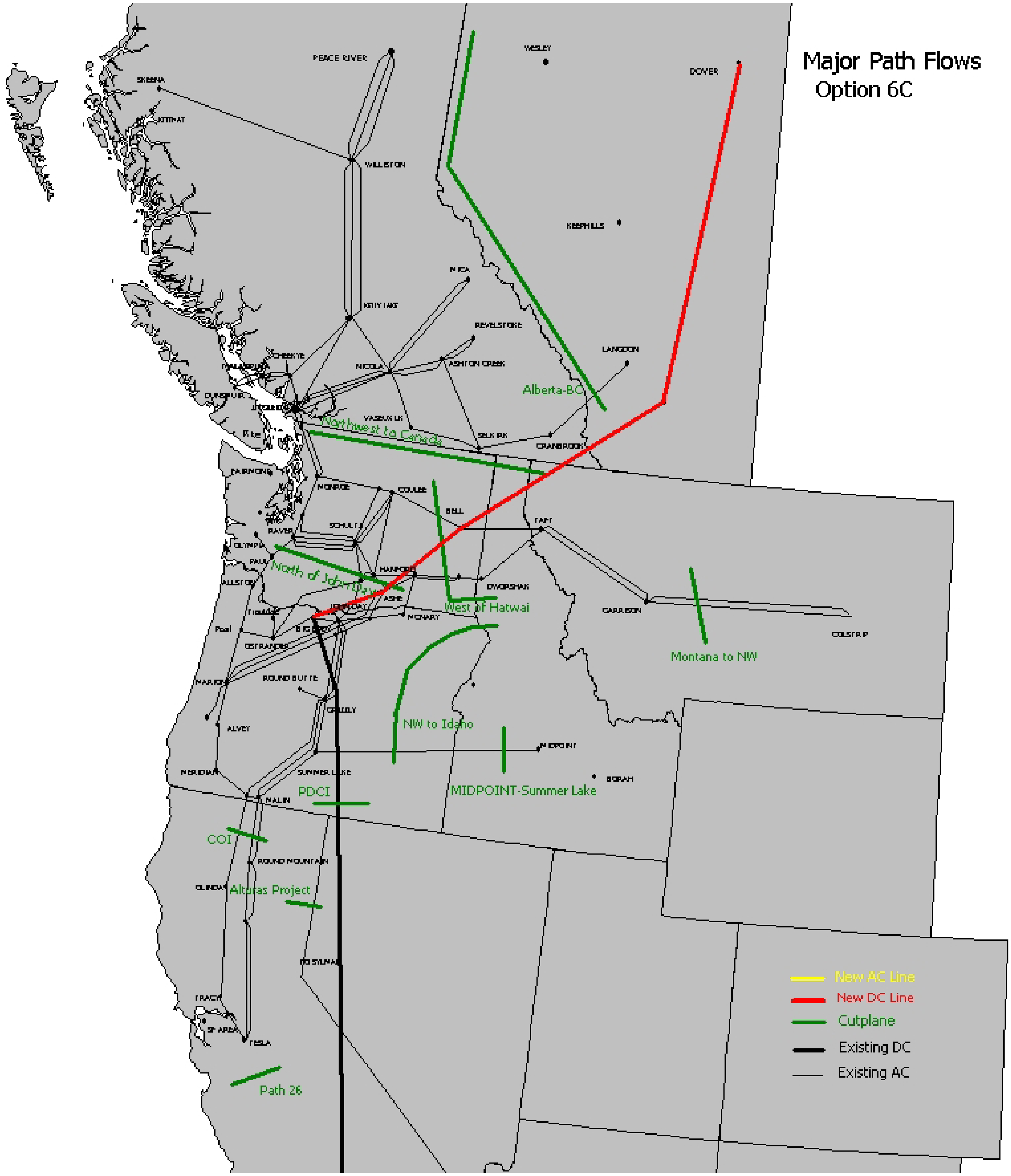
Dover	541 KV	152.22 Deg
Langdon	546 KV	132.79 Deg
Peace River	530 KV	111.08 Deg
Nicola	526 KV	98.34 Deg
Ingledow	519 KV	82.98 Deg
Bell	537 KV	82.07 Deg
Coulee	540 KV	76.93 Deg
Monroe	538 KV	70.99 Deg
John Day	540 KV	41.24 Deg
Malin	542 KV	18.62 Deg
Garrison	538 KV	85.74 Deg
Midpoint	538 KV	25.41 Deg
Tesla	532 KV	0.24 Deg

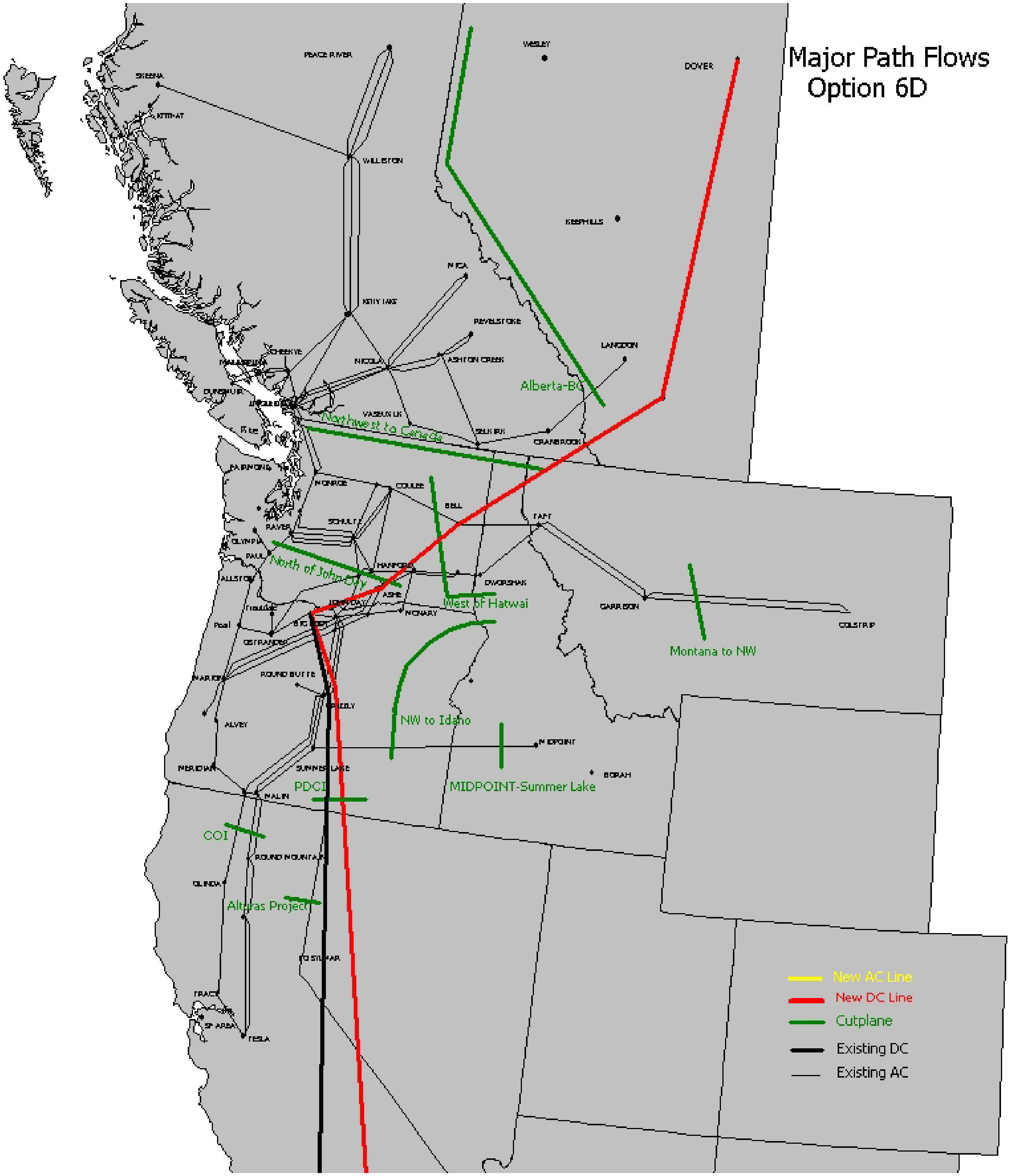


Major Path Flows
Option 6A

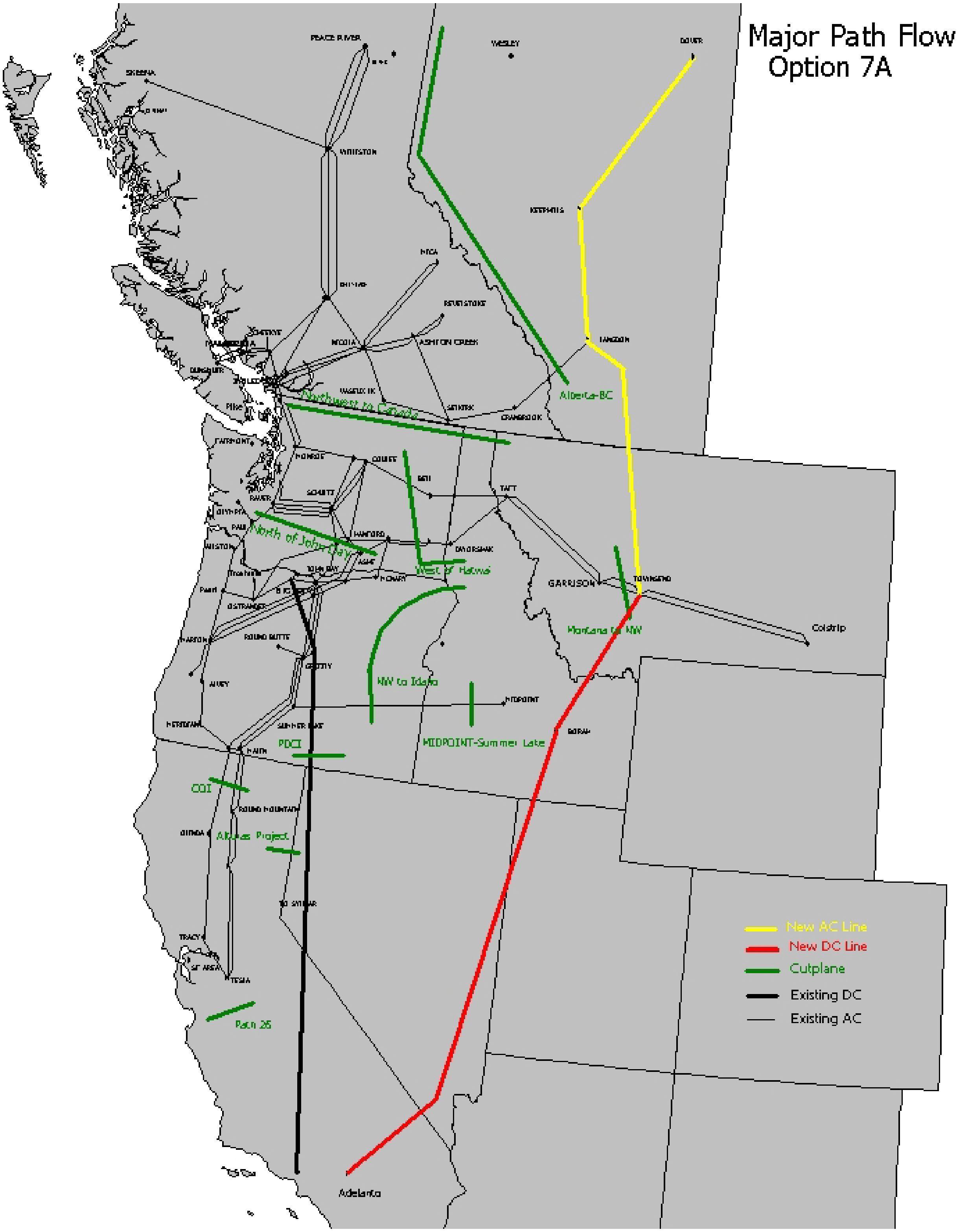


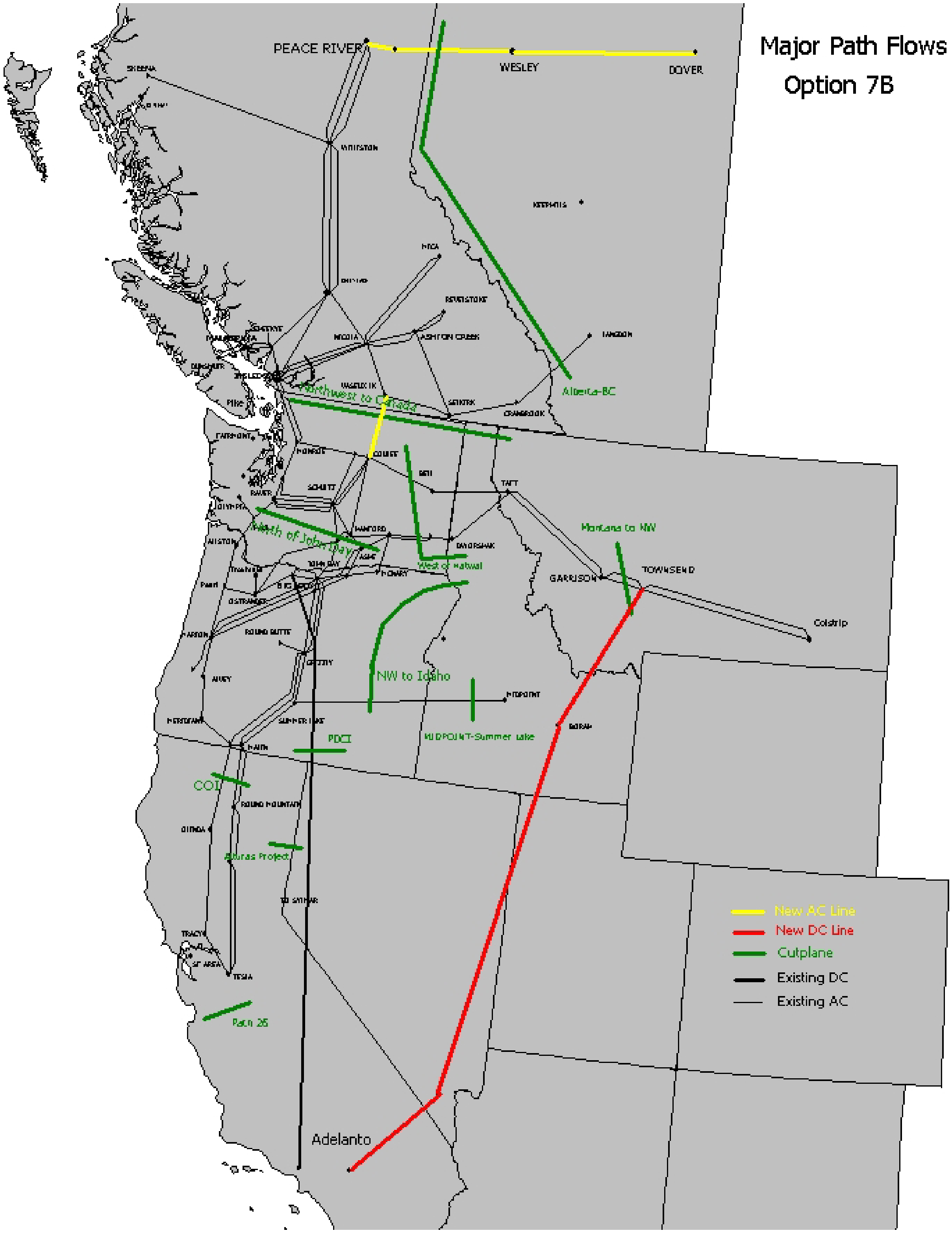
Major Path Flows
Option 6B
PEACE RIVER
WESLEY
DOVER
SKEENA
KITIMAT
WILLISTON
KEEPHILLS
MICA
KELLY LAKE
REVELSTOKE
LANGDON
CHEEKYE
MALASPINA
NICOLA
ASHTON CREEK
DUNSMUIR
INGLEDOW
Alberta-BC
VASEUX LK
Northwest to Canada
Pike
SELKIRK
CRANBROOK
FAIRMONT
MONROE
COULEE
BELL
TAFT
SCHULTZ
OLYMPIA
RAVER
PAUL
North of John Day
HANFORD
DWORSHAK
ALLSTON
ASHE
JOHN DAY
West of Hatwai
GARRISON
Troutdale
MCNARY
Pearl
BIG EDDY
COLSTRIP
OSTRANDER
Montana to NW
MARION
ROUND BUTTE
GRIZZLY
ALVEY
NW to Idaho
MIDPOINT
MERIDIAN
SUMMER LAKE
BORAH
PDCI
MIDPOINT-Summer Lake
MALIN
COI
ROUND MOUNTAIN
OLINDA
Alturas Project
LOS BANOS
TRACY
SF AREA
TESLA
Path 26
New AC Line
New DC Line
Cutplane
Existing DC
Existing AC

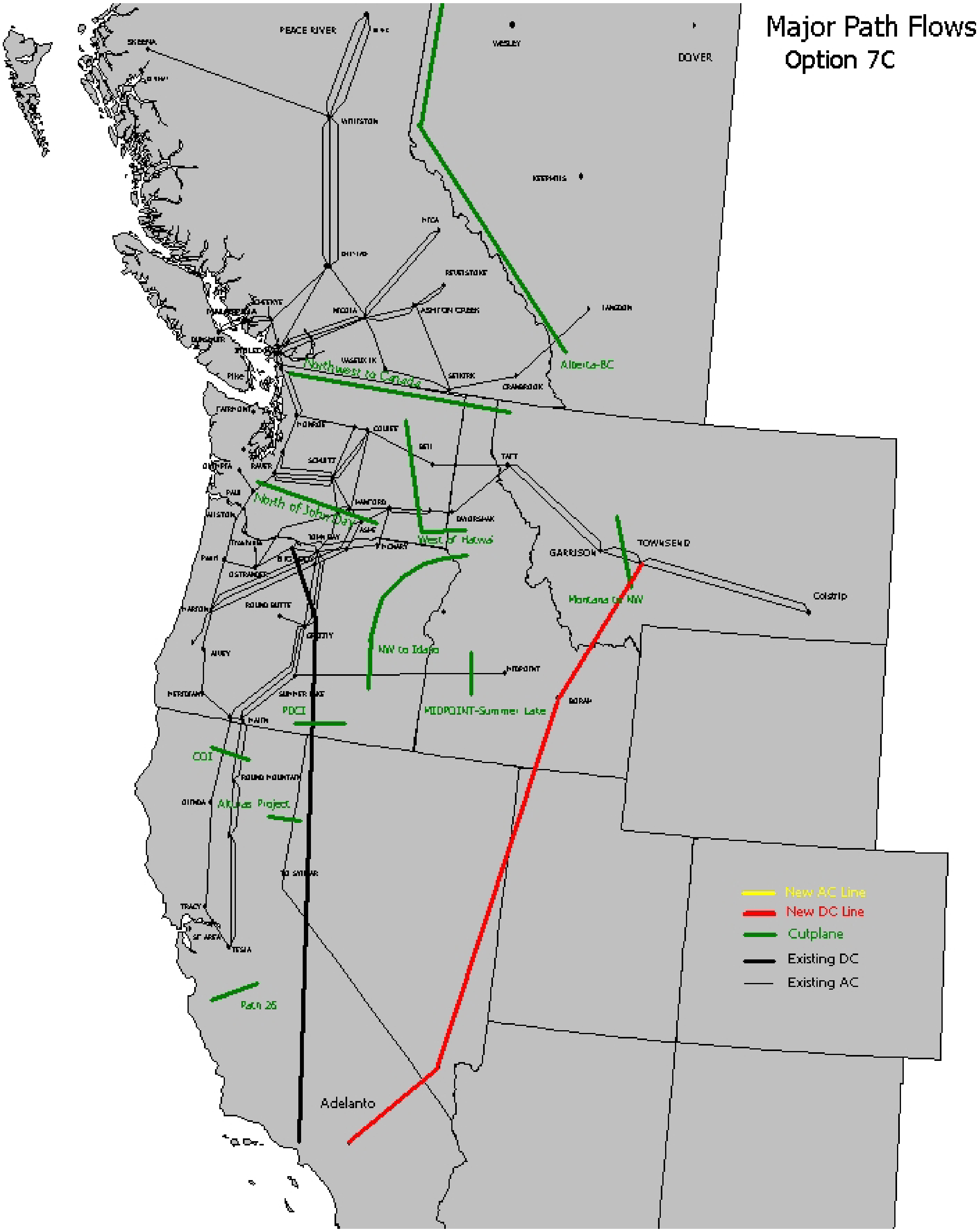

Major Path Flows
Option 6C
PEACE RIVER
WESLEY
DOVER
SKEENA
KITIMAT
WILLISTON
KEEPHILLS
MICA
KELLY LAKE
REVELSTOKE
LANGDON
CHEEKYE
ASHTON CREEK
NICOLA
DUNSMUIR
Alberta-BC
VASEUX LK
Northwest to Canada
SELKIRK
CRANBROOK
MONROE
COULEE
BELL
TAFT
SCHULTZ
RAVER
OLYMPIA
PAUL
North of John Day
HANFORD
DWORSHAK
ALLSTON
ASHE
West of Hatwai
GARRISON
Troutdale
JOHN DAY
MCNARY
Pearl
BIG EDDY
COLSTRIP
OSTRANDER
Montana to NW
ROUND BUTTE
MARION
GRIZZLY
ALVEY
NW to Idaho
MIDPOINT
MERIDIAN
SUMMER LAKE
BORAH
PDCI
MALIN
MIDPOINT-Summer Lake
COI
ROUND MOUNTAIN
OLINDA
Alturas Project
TO SYLMAR
TRACY
SF AREA
TESLA
Path 26
New AC Line
New DC Line
Cutplane
Existing DC
Existing AC

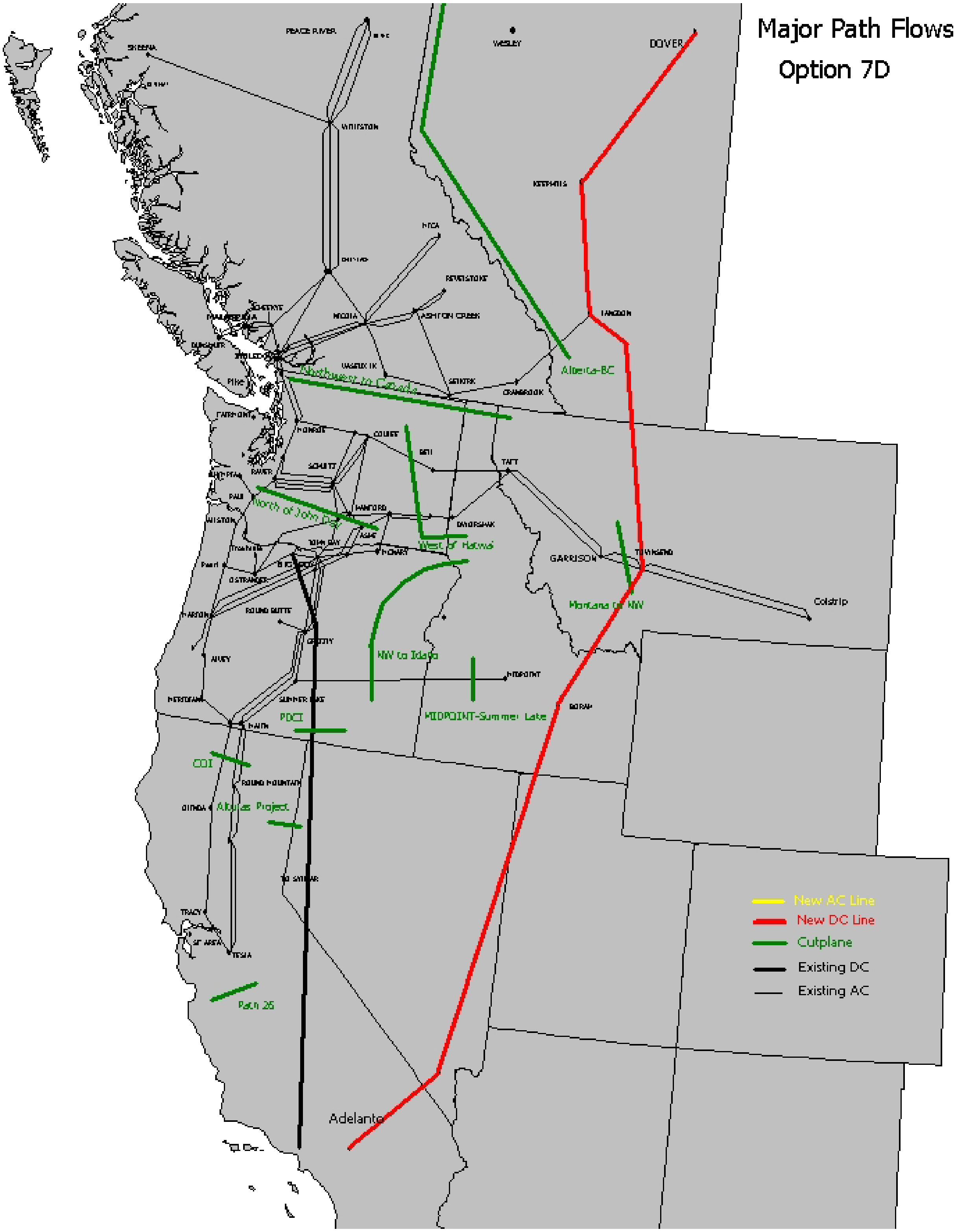

Major Path Flows
Option 6D
PEACE RIVER
SKEENA
KITIMAT
WILLISTON
WESLEY
DOVER
KEEPHILLS
MICA
KELLY LAKE
REVELSTOKE
LANGDON
CHEEKYE
NICOLA
ASHTON CREEK
MALASPINA
DUNSMUIR
Alberta-BC
VASEUX LK
Northwest to Canada
SELKIRK
CRANBROOK
MONROE
COULEE
BELL
TAFT
RAVER
SCHULTZ
OLYMPIA
PAUL
North of John Day
HANFORD
DWORSHAK
ALLSTON
ASHE
West of Hatwai
GARRISON
Troutdale
MCNARY
COLSTRIP
Pearl
BIG EDDY
OSTRANDER
Montana to NW
MARION
ROUND BUTTE
GRIZZLY
ALVEY
NW to Idaho
MIDPOINT
MERIDIAN
SUMMER LAKE
BORAH
PDCI
MIDPOINT-Summer Lake
MALIN
COI
ROUND MOUNTAIN
OLINDA
Alturas Project
TRACY
SF AREA
TESLA
New AC Line
New DC Line
Cutplane
Existing DC
Existing AC

Major Path Flows Option 7A



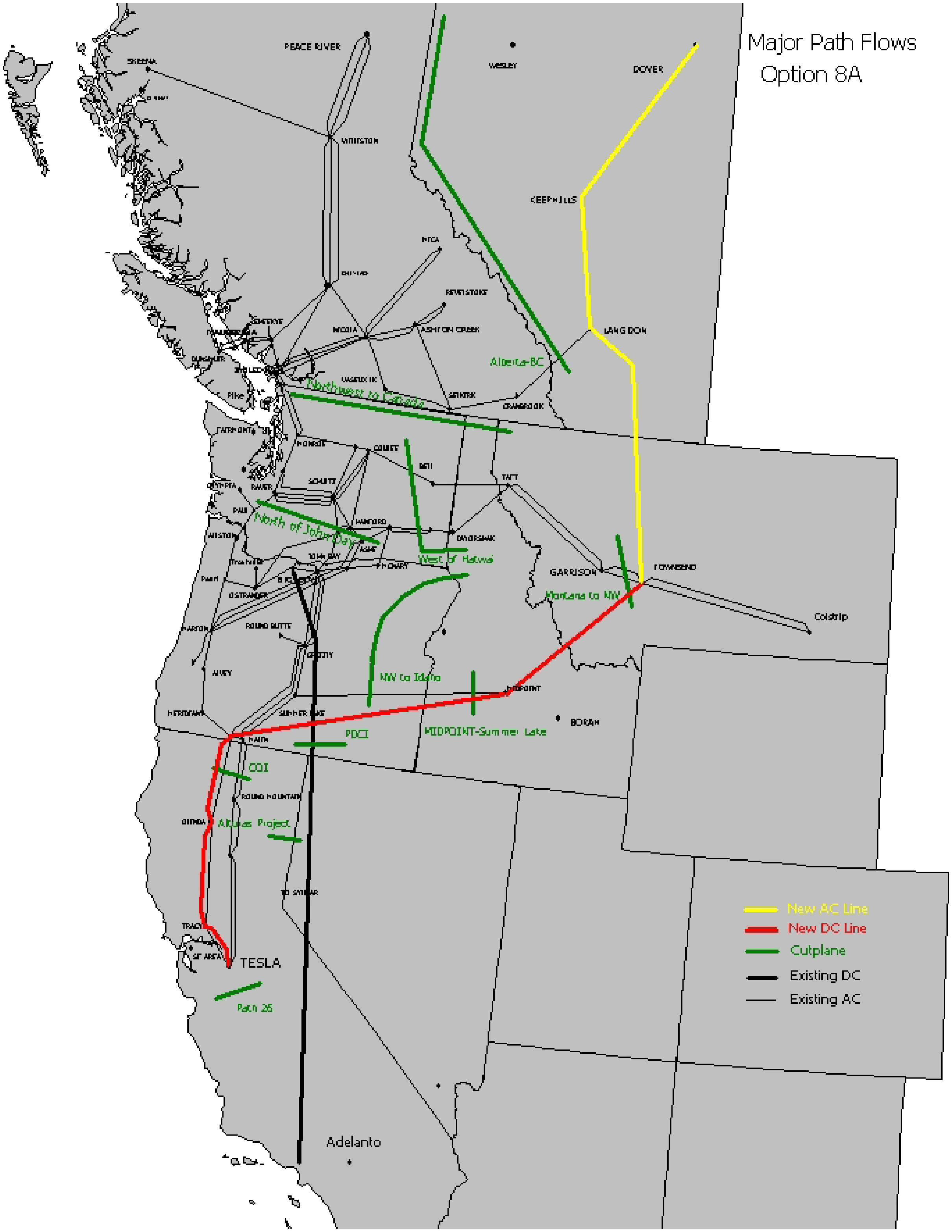

Major Path Flows
Option 7B
PEACE RIVER
WESLEY
DOVER
SKEENA
WILLISTON
KEEPHILLS
MICA
REVELSTOKE
LANGDON
NICOLA
ASHTON CREEK
Alberta-BC
Northwest to Canada
SELKIRK
CRANBROOK
FAIRMONT
MONROE
COULEE
BELL
TAFT
SCHULTZ
RAVER
OLYMPIA
North of John Day
HANFORD
ALLSTON
Montana to NW
DWORSHAK
West of Hatwai
TOWNSEND
GARRISON
JOHN DAY
ASHE
McNARY
BIG EDDY
OSTRANDER
Colstrip
PEARL
ROUND BUTTE
GRIZZLY
NW to Idaho
ALVEY
MIDPOINT
MERIDIAN
SUMMER LAKE
BORAH
MIDPOINT-Summer Lake
PDCI
MALIN
COI
ROUND MOUNTAIN
Alturas Project
OLINDA
TABLE MTN
TRACY
SF AREA
TESLA
Path 26
Adelanto
New AC Line
New DC Line
Cutplane
Existing DC
Existing AC

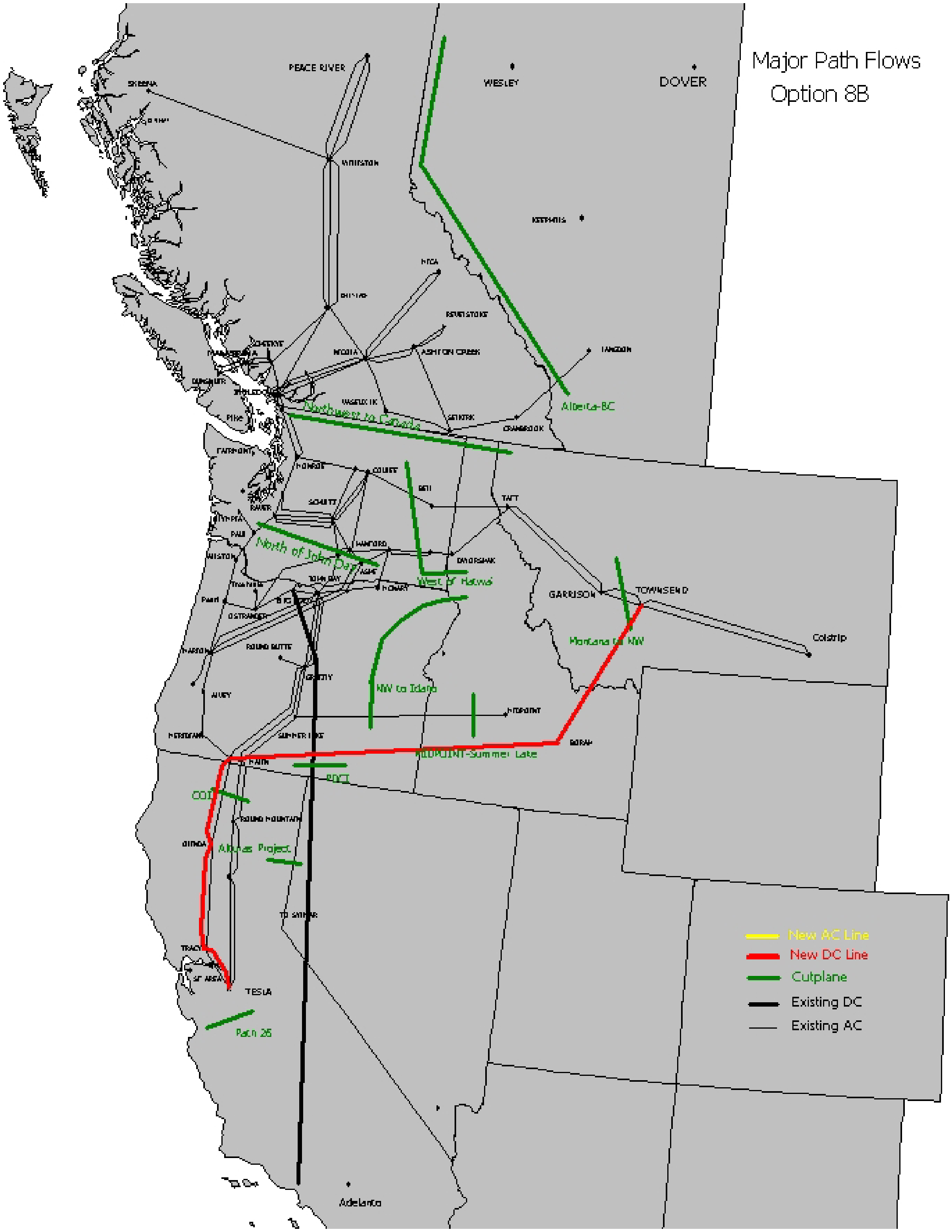

Major Path Flows
Option 7C
PEACE RIVER
WESLEY
DOVER
SKEENA
WILLISTON
KEEPHILLS
NICOLA
ASHTON CREEK
REVELSTOKE
LANGDON
Alberta-BC
Northwest to Canada
CRANBROOK
MONROE
COULEE
BELL
TAFT
SCHULTZ
RAVER
North of John Day
HANFORD
DWORSHAK
ASHE
JOHN DAY
West of Hatwai
GARRISON
TOWNSEND
Colstrip
Montana to NW
ROUND BUTTE
GRIZZLY
NW to Idaho
MIDPOINT
SUMMER LAKE
PDCI
MIDPOINT-Summer Lake
BORAH
MALIN
COI
ROUND MOUNTAIN
Alturas Project
TRACY
TESLA
Path 26
Adelanto
New AC Line
New DC Line
Cutplane
Existing DC
Existing AC



Major Path Flows

Option 7D


Major Path Flows
Option 8A
PEACE RIVER
SKEENA
WESLEY
DOVER
WILLISTON
KEEPHILLS
MICA
REVELSTOKE
NICOLA
ASHTON CREEK
LANGDON
Alberta-BC
Pike
Northwest to Canada
SELKIRK
CRANBROOK
FAIRMONT
MONROE
COULEE
BELL
SCHULTZ
TAFT
OLYMPIA
RAVER
PAUL
North of John Day
HANFORD
ALLSTON
DWORSHAK
ASHE
JOHN DAY
West of Hatwai
GARRISON
TOWNSEND
Montana to NW
Colstrip
OSTRANDER
ROUND BUTTE
GRIZZLY
ALVEY
NW to Idaho
MIDPOINT
BORAH
SUMMER LAKE
MERIDIAN
MALIN
PDCI
MIDPOINT-Summer Lake
COI
ROUND MOUNTAIN
OLINDA
Alturas Project
TO SYLMAR
TRACY
TESLA
Path 26
Adelanto
New AC Line
New DC Line
Cutplane
Existing DC
Existing AC



Major Path Flows
Option 8B

Appendix 3 – User Manual for Options Analysis Workbook

Introduction

This is a manual for the Options Analysis Workbook, an Excel workbook created by the project team in early 2006 to present the transmission cost estimates and to derive unit costs of delivering energy from resources in Western Canada and in Montana to the US Pacific Northwest and to California. The model resides on the NTAC web site ***www.nwpp.org/ntac/pdf/CNC_Options_Analysis_Tool_-_2006.xls.***

The workbook provides:

- Schematics of 8 basic transmission expansion schemes
- Capital cost estimates for these.
- Capital, fuel and operating costs for numerous types of generating resources, as derived from recent publications including the Northwest Power and Conservation Council's 5th Development Plan and BC Hydro's Integrated Resource Plan.
- Derivations of costs of electricity at the plant gate and at US load centers.
- Summaries of the results in alternative formats.

The workbook is incorporates contributions and suggestions from a great many individuals in the CNC Study Group.

Program Requirements and Machine Settings

The workbook was created with a screen resolution of 1024 x 768 pixels and may be awkward to use or appear unattractive with other settings. (To view or change your settings go Start→ Control Panel→ Display → Settings.)

It was created in Excel 2003. Some of the worksheets have buttons to allow the user to choose between cost estimates put forth by public enterprises or merchant enterprises. These do not seem to work in versions preceding Excel 2000.

The Visual Basic logic that operates the buttons registers as a macro in Excel and invokes a warning if the security level on your own Excel program is set at a high level. If you elect to stay at a high security level, the buttons will be disabled. To change to a lower level go Tools→Macros→Security and choose Moderate or Low. With a "moderate" setting, it will still be necessary to click "enable macros".

Component Sheets

The model comprises the following sheets or types of sheets:

Console

The console is for data entry for items that are common to several or all options such as escalation rates, capital charge rates, unit costs for transmission equipment items, primary energy costs, loss factors and exchange rates. Cells where data can be entered are shaded in light green.

For coding purposes (and for ease of interpreting the code) all variables that appear on the console are “named variables”. In cells that contain formulas, the variable name appears in the formula in place of the cell address. A list of variable names and their location in the workbook is provided in the “Variable List” sheet at the far right of the workbook.

Summary

This summarizes the levelized real unit costs for each resource option within each of the transmission options. There are:

- Up to 3 resource alternatives (coal , hydro or cogeneration, for example) for each transmission option.
- 8 major transmission options.
- Several sub-options to the major transmission options. (Option 2 comprises sub-options 2a and 2b for example.)

The unit cost are provided for generating costs at the plant gate (exiting the power plant), for the transmission system (capital charges plus operating costs) and for transmission system losses.

The “real levelized unit cost” is the value that, when escalated at the general rate of inflation over the project life, provides a revenue stream with the same present worth as the capital and operating outlays.

Summary Chart 1

This sets out levelized real unit costs for each transmission option. Only the resource alternative that gives the lowest delivered cost is shown for each. (The resource option with the lowest cost at the plant gate is not always the alternative with the lowest delivered cost since some require less transmission investment.)

Summary Chart 2

This sets out levelized real unit costs for each resource alternative within each transmission option. All of the cases that are reviewed in the subsequent worksheets appear in this summary.

Chart 3 and Summary Chart 3

These set out the levelized real unit costs for the resource alternatives and transmission options that were deemed to be of most interest for the executive summary of the Can-NW-Cal study report.

Option Cost Summary

This summarizes the total capital costs for each transmission option.

Gen Costs

This contains the parameters for each generating resource.

The top section, “System Parameters”, is where information is entered on capital costs (in $.kW), efficiencies, operating costs project lives, and greenhouse gas emissions.

The lower section derives unit costs of energy on two bases:
for the first year assuming capital charges (in 2005 dollars) are fixed for the project life and
on a levelized real basis.

X Map (where X has the value 1 to 8)

These are schematics/maps showing the route and type of transmission system for each option.

X System

This sheet is the cost estimate for the transmission option.

Segments of the transmission line route appear in rows. The number of equipment items of each type that are required for the segment appear in columns. For options capable of delivering to the US Pacific Northwest and to California, a green line marks the where investment required solely for California begins.

The lengths of each type of line and the numbers of each type of equipment are totalled for each column and these are multiplied by the unit costs from the console. The column totals are summed to obtain the total estimate for the option.

X Econ (Where X is the number of the transmission option or sub-option)

This sheet derives the unit costs of the generating resource at the plant gate, the unit cost of the transmission system, the loss percentage and the cost of losses.

There is provision for 3 alternative generating alternatives, alternatives A, B and C, (color coded green, blue and yellow) for each resource. Each alternative has a sub-alternative 1 and 2 – “1” for delivery to California and “2” for delivery to the US Pacific Northwest.

Section 1 Case Description:

The key description of the transmission line routing appears here. The cell containing the description is referenced in the “Summary” and flows from the “Summary” sheet to the sheets containing the summary chart data. (If you want to change the option description, here is where to do it.)

This section also contains the description of the generating resource and its location. These are also referenced in the summary and flow from the summary to the summary charts.

Section 2 Generating System:

This section contains parameters for the generating resource in a format similar to the "Gen Costs" sheet so data can conveniently be copied from the "Gen Costs" sheet or referenced to it. It is not necessary to use data from the "Gen Costs" sheet here, however. Users may wish to use most of the "Gen Costs" parameters but apply unique capacities and capacity factors here.

Several alternatives use combinations of generating alternatives, the types of generating plant being at different locations. In these cases the costs of each resource are calculated separately and the values are weighted according to the energy produced by each resource, to obtain a combined value. In these cases, the calculations for each generating resource are carried out at the right of the spreadsheet and the weighted values are carried to the appropriate column.

Section 3 Transmission System Additions:

The "Total Capital Additions" row in this section references the appropriate cell in the "X Sys" sheet.

The "Loss Percentage" row derives the loss percentages (or references cells to the right where loss values are weighted for combinations of generating alternatives).

Section 4a Costs at Start of 2005 ($US x 1000)

This section sets out the revenue that would be required in 2005$ (and the corresponding tariff) if the capital charges were fixed for the project life, as in a home mortgage. With this tariff, unit capital charges would remain the same from year to year but operating costs would escalate.

Section 4b Levelized Real Costs ($US x 1000) (All components escalating from the start of 2005)

This section sets out the revenue that would be required in 2005$ (and the corresponding tariff) if the charges were allowed to escalate each year.

Data Entry

Data can be entered in 4 locations:

- On Console Sheet. These are global items that can be readily changed for sensitivity analysis.
- On the System Parameters Section of the Gen Costs Sheet. This is for generating system parameters and costs.
- In the top 28 rows of the “X Sys” sheets. Lengths of segments and numbers of components for each segment can be changed here but care should be taken that totals to the Pac NW and California are being calculated correctly.
- In the “X Econ” sheets. Descriptions can be changed in the Case Description Section and generating unit parameters can be changed in the “Generating System” section

Viewing Results

Totals for transmission system cost estimates can seen at the bottom left corner of the “X Sys” sheets.

Total unit costs for each resource alternative for each transmission option can be seen at the bottom of sections 4a and 4b of the X Econ Sheets.

Unit cost for standard generating alternatives can be seen on the bottom half of the Gen Costs sheets.

Total capital costs for each transmission option appear on the Option Cost Summary sheet.

Real Levelized Unit Costs appear on the Summary, Summary Chart 1, Summary Chart 2, Chart 3 and Summary Chart 3 sheets.

Appendix 4 – Glossary

AFUDC: Allowance for Funds Used During Construction.

Avg MW: The average amount of energy (in megawatts) supplied or demanded over a specified period of time; equivalent to the energy produced by the continuous operation of one megawatt of capacity over the specified period.

CHP: Combined Heat and Power, used in this report in the context of congeneration opportunities for the Oil Sands

IGCC: Integrated coal Gasification Combined Cycle;

Levelized Costs: The present value of the total cost of building and operating a generating plant over its economic life, converted to equal annual payments. Costs are levelized in real dollars (i.e., adjusted to remove the impact of inflation).

N-1 Contingency: An event that results in a single transmission line being forced (or taken) out of service.

N-2 Contingency: An event that results in two transmission lines being forced (or taken) out of service.

P50 estimates: A cost estimate for which there is an equal probability that the actual costs will be higher or lower than the estimate

RAS: Remedial Action Schemes are special protection systems that ensure that corrective actions take place immediately following the forced outage of a transmission line or transmission system element.