Montana – Dakotas Regional Transmission Study

WEST SIDE STUDIES
PROJECT 2

Western AREA POWER ADMINISTRATION

UPPER GREAT PLAINS REGION
Transmission Planning

JULY 2002

TABLE OF CONTENTS

PROJECT 2 SUMMARY

A 1000 MW gas-fired generation facility was modeled near Great Falls, Montana. Three separate 500 kV transmission line alternatives were studied in terms of their export capability for the new generation. Export areas studied included Spokane (NORTHWEST), North Lethbridge (ALBERTA), Salt Lake City (PACE), and Denver (PSCOLORADO). Estimated costs ranged from $263 million to $566 million for the three transmission line alternatives.

The Project caused an overall increase in real power losses for the Line 1 and Line 2 cases. Line 3 models experienced a net decrease in real power system losses. For most cases, reactive power losses were decreased, with the exception being the case with the Great Fall to Spokane line.

For each transmission line and schedule combination, the impact of the added facilities on the existing system was gauged in terms of the merged NERC/WECC Planning Standards. The largest quantity of Category A violations occurred for Line 3 scheduled to Lethbridge; however, this case also claimed the most improvements. Line 2 with schedule to Denver created the fewest new Category A violations.

Category B violations were most prominent for the Salt Lake City schedule with Line 2 routed to Denver in service. Line 3 scheduled to Lethbridge reported the least number of new violations and the most fixed violations, including significant offloading of the Northwest area. Line 2 routed to Denver also demonstrated minimal negative impact to the system during contingency conditions; however stability of the Fort Peck Unit 1 hydro generator was negatively affected.

In general, increased strain to existing facilities at the load centers of Spokane and Denver was observed. This increased strain is highlighted by Category B violations during nearby contingencies. Known constraints such as Amps and Bonanza were shown to be the most susceptible to contingencies on the Project line sections. These same constraints also received the largest benefits brought about by the offloading of power transfers to the new 500 kV transmission paths.

Most of the fault simulations performed during dynamic analysis demonstrated stable system performance. The Project created two cases which resulted in instability on parts of the system. Fort Peck hydro generator was shown to be unstable for the single-line-to-ground fault at Great Falls 230 kV with Line 2 scheduled to Denver. The majority of the Alberta system experienced voltage collapse followed by prolonged frequency depressions as low as 58.56 Hz for outages on the new Great Falls-Lethbridge 500 kV line. Additional power imports to Alberta will be limited by the system’s ability to respond promptly to branch interface outages.

An evaluation of each of the analyses was completed to determine the overall feasibility of each of the transmission alternatives. Table 7 summarizes these conclusions. The most viable transmission line options studied for Project 2 are Line 1 to Spokane and Line 3 to Salt Lake City. System intact and stability was acceptable for these two line options. Contingencies which were impacted by the Project would need to be addressed during project development. The specific impacts for Line 1 to Spokane are localized to the delivery point of Bell Substation. For Line 3 to Salt Lake City, impact is mainly on the existing Amps transfer constraint and adjacent 161 kV system. Recommendations for dealing with the contingency issues are included in the contingency analysis summaries found in the appendices.

1. INTRODUCTION AND PROJECT SCOPE

Project 2 of the Montana Transmission Study investigates the effects of a power plant near Great Falls, Montana. Three 500 kV transmission line routes were used to schedule power to four different load centers.

1.1 Scope

The Project simulated a 1000 MW Gas-fired generation plant near Great Falls. The new plant was attached to the existing system via a 40 mile double-circuit to a new 500 kV bus at Great Falls. The new 500 kV bus tied into the existing 230 kV bus via an transformer. The following transmission alternatives were investigated with corresponding load flow schedules. For the purpose of discussion, each alternative is referred to as “Line 1”, “Line 2”, and “Line 3” hereafter.

Line 1: 500 kV line from Great Falls, Montana to Spokane, Washington

- Scheduled to Spokane

Line 2: 500 kV line from Great Falls, Montana to Denver, Colorado

- Scheduled to Denver
- Scheduled to Salt Lake City

Line 3: 500 kV line from Lethbridge, Alberta to Great Falls, Montana to Salt Lake City, Utah.

- Scheduled to Salt Lake City
- Scheduled to Lethbridge

Project maps illustrating the line routing for each of the transmission alternatives can be found in the Appendices. Figure 1 illustrates the line routing for Line 1. From Great Falls, the transmission line was connected to the existing 500 kV bus at Hot Springs, and again at the existing 500 kV bus at Bell.

Figure 2 shows the studied line route for Line 2. Facility attachment points are Great Falls, Broadview, Colstrip, Dave Johnston, and Daniels Park. The new line route to Denver is discontinuous because the existing 500 kV double circuit from Broadview to Colstrip has sufficient capacity to carry scheduled power flows.

Figure 3 demonstrates line routing for Line 3. The line begins at North Lethbridge and makes connections at Great Falls, Townsend, Dillon, Kinport, and Ben Lomond. Based on power flow results from a similar line route in Project 1, Line 3 makes a connection point to the existing 500 kV system at Townsend. Although switching facilities do not presently exist at Townsend, this point was chosen in order to determine the effects that Line 3 would have on the existing Broadview to Garrison double circuit line.

2. DESCRIPTION OF THE BASE CASES

Two models obtained from the Western Electricity Coordinating Council (WECC) were used to build the Project models. From these, five additional system models were established in order to study and compare the different combinations of transmission lines and schedules. In all cases, the additional Project generation was scheduled by reducing generation in the destination area.

2.1 Line 1 Scheduled to Spokane

The Spokane Line 1 model represents the Project generator scheduled to the Spokane area. SPL1 is based on the WECC 2002 Light Summer model, which represents worst-case flows from Montana to Washington.

Static VAR Compensators (SVC's) were added at the new Great Falls 500 kV bus and at the Hot Springs 500 kV bus to counteract excessive voltage rise due to line charging.

Area schedules were modified to reflect 1000 MW of additional export from Montana, and 1000 MW of additional import to Northwest. The swing generators in each of these areas experienced minimal changes in their swing megawatts, and were therefore permitted to adjust for the new system conditions.

2.2 Line 2 Scheduled to Denver

This model represents Project generation scheduled to Denver with Line 2 in service. It is based on the WECC 2002 Heavy Summer model.

The following buses required additional SVC's to maintain desired voltage levels:

- Broadview 500 kV
- Colstrip 500 kV
- Dave Johnston 500 kV

Of the 1000 MW of new Project generation added to the system, 960 MW was scheduled to the Colorado area. This was done in order to minimize the changes to the swing generators.

2.3 Line 2 Scheduled to Salt Lake City

The next model represents the Project generation scheduled to Salt Lake City with Line 2 (to Denver) in service. Additional SVC's required are the same as for Line 2 Scheduled to Denver. This model is based on the WECC 2002 Heavy Summer model. Additional power scheduled to Salt Lake City was 940 MW.

2.4 Line 3 Scheduled to Salt Lake City

Based on the WECC 2002 Heavy Summer case, this model simulates power scheduled to Salt Lake City with Line 3 in service. SVC's were added at the Lethbridge, Great Falls, and Dillon 500 kV buses. Of the 1000 MW of new Project generation, 960 MW was scheduled to Salt Lake City.

2.5 Line 3 Scheduled to Lethbridge

With Line 3 in service, Project generation was scheduled to Lethbridge. SVC's are present on the new 500 kV system at Lethbridge, Great Falls, and Dillon. A schedule of 1000 MW was achieved with minimal effect on the swing generators. This model is based on the WECC 2002 Heavy Summer model.

3. POWER FLOW ANALYSIS

Two power flow conditions were studied: Category A and Category B. The effect of the Project was gauged by comparing Pre-Project and Post-Project rating and voltage violations. Additionally, power losses were studied for Category A conditions.

3.1 Category A Power Losses

Table 1 summarizes the change in system losses due to the Project. Losses are sorted by area, and are broken up into real power (MW) and reactive power (MVAR) losses. Please note that only those areas with significant changes are included in Table 1. Positive values in the table indicate an increase in system losses, whereas negative values indicate that losses decreased. Values in bold text indicate the area to which the Project has been scheduled. For example, Spokane is located in the Northwest area, and Salt Lake City is within the PACE area.

Table 1 - Project Effect on System Losses by Area

Line Code -->	L1		L2		L2		L3		L3	
Schedule -->	Spokane		Denver		Salt Lake City		Salt Lake City		Lethbridge	
	MW	MVAR	MW	MVAR	MW	MVAR	MW	MVAR	MW	MVAR
Total System	83	199	29	-1173	84	-755	-41	-1937	-126	-2964
Northwest	**56**	**-61**	10	173	31	444	-8	-93	-89	-1185
B.C. Hydro	9	70	1	14	2	25	2	16	4	106
Alberta	0	0	0	0	0	0	1	-522	**-4**	**-580**
Idaho	3	27	-2	-21	-21	-253	-44	-377	-7	31
Montana	13	138	38	-668	56	-577	49	-264	9	-720
WAPA U.M.	0	0	0	1	0	-2	0	0	-2	-27
PACE	1	13	-2	-23	**41**	**374**	**-38**	**-653**	-38	-597
Colorado	0	2	**-11**	**-600**	-30	-861	0	-3	1	6
WAPA R.M.	1	14	-5	-47	5	97	-2	-28	-1	7

The effect of the Project on power losses is primarily dependent on the combination of the Project line route and the Project schedule. Table 1 indicates that the most detrimental change in total system losses occurred for Line 1 scheduled to Spokane.

The most beneficial change overall occurred for Line 3 scheduled to Lethbridge. Large decreases in reactive power losses (MVARs) can be seen in the majority of Table 1. These decreases are the result of line charging on the new transmission line.

As can be expected, significant changes occur in the Montana export area and the import area (values in bold). However, due to the physical power flow paths, the Project can be seen to have a noticeable impact on surrounding areas as well. This is particularly evident for Line 2 when scheduled to Salt Lake City. Because Line 2 does not route directly to Salt Lake City, a significant amount of the additional imports must come from other transmission paths and sources. Heavier loading and longer power flow distances result in increased losses in the Northwest, Montana, PACE, and WAPA Rocky Mountain (R.M.) areas. Conversely, offloading of existing lines due to an improved flow path caused by Line 2 result in decreased losses in the Idaho and Colorado areas.

3.2 Category A Violations

Table 2 presents the number of Category A rating and voltage violations which were affected by the Project. The first results column gives the number of violations caused or worsened by the Project. The second results column gives violations which were fixed or improved by the Project.

Table 2 - Category A Violations Summary

Line Code	Schedule	Area Name	Violations caused or worsened by 5%		Violations fixed or improved by 5%	
			Ratings	Voltage	Ratings	Voltage
L1	Spokane	Northwest	-	-	3	2
		B.C. Hydro	-	3	-	-
L2	Denver	Northwest	-	1	-	1
		B.C. Hydro	-	-	-	2
		PACE	-	1	-	-
	Salt Lake City	B.C. Hydro	-	-	-	2
		Montana	-	4	-	-
		PACE	2	3	-	2
L3	Salt Lake City	B.C. Hydro	-	1	-	4
		Alberta	-	2	-	5
		PACE	-	2	-	-
	Lethbridge	Northwest	-	-	-	2
		B.C. Hydro	-	19	-	1
		W Kootenay	-	6	-	-
		Alberta	3	14	1	33
		PACE	-	1	-	2

3.2.1 Line 1 Scheduled to Spokane

For Line 1 scheduled to Spokane, Table 2 indicates the addition of three new voltage violations (1.05 pu) in British Columbia. The rise in voltage on these buses is likely the result of offloading of the BPA system due to Line 1. Two existing overvoltage violations (1.05 pu) on the 115 kV buses “HANLY R1” and “RINGOLD” were brought just below 1.05 pu of nominal by the Project.

Three rating violations in the Northwest area are shown to be fixed for the schedule to Spokane. The two “CHIEFJO” Generator Step-Up (GSU) transformers, and the “COUGAR T” GSU experience 6% and 4% decreases respectively in their loading. This decrease is due to a reduction of generator output due to the scheduling method, and can not be considered an improvement brought about by the Project.

3.2.2 Line 2 Scheduled to Denver

The Project’s Line 2 with schedule to Denver had minimal effect on the system in terms of violations. Table 2 indicates two new voltage violations. In the Northwest area, voltage on the “BELL BPA” 500 kV line is reduced from 1.07 pu to 1.049 pu. In the PACE area, voltage at Big Grassy 161 kV drops from slightly 0.96 pu to 0.948 pu, indicating slightly increased flows through the Amps constraint area.

An important observation should be made that the new power plant at Great Falls primarily helps to serve load requirements in the Northwest area despite the fact that the new generation was scheduled to Denver. In turn, some of the existing generation at Colstrip is offset from serving the Northwest loads to serving the new load centers in Denver. Recognition of this fact indicates that the transmission alternatives which best serve new generation near Great Falls are those which coincide with the flow direction to the Northwest area. In other words, a transmission alternative which focuses on supplying power from Colstrip to Denver, and power from Great Falls to Spokane may improve the ability to serve both markets. Improved system performance may also be realized through an overall reduction in system losses.

A total of three overvoltage violations were reported as fixed for this case, however the buses involved experienced minimal change in their actual voltage. All of these overvoltages were reduced from values slightly above 1.05 pu to just below 1.05 pu.

3.2.3 Line 2 Scheduled to Salt Lake City

Two new rating violations occur in the Line 2 to Salt Lake City case. They indicate heavy exports along the known Amps constraint in Idaho, and heavy flows from Colorado into Utah caused by the addition of Line 2 which is routed to Denver.

- Jefferson 161 kV phase shifting transformer in Idaho (PACE area); 119% of 100 MVA rating
- Bonanza 345 kV to Mona 345 kV line section in Utah (PACE area); 118% of 650 MVA rating

Category A voltage violations for this line and schedule combination are related to the Amps constraint. In southwestern Montana, the 161 kV transmission path through buses "ENNIS MT", "SHERDNMT", "DILLON S", "BIGGRASS", and "JFRSNPHA" experienced undervoltage as low as 0.919 pu (at Big Grassy). In comparison, the lowest base-case voltage along this 161 kV path is 0.961 pu (also at Big Grassy). Undervoltage violations were also observed on the Peterson Flats 230 kV bus and the Amps 230 kV bus. Voltage at Peterson Flats 230 kV dropped from 0.969 pu in the base-case to 0.925 pu in the scheduled case.

A total of four overvoltage violations just above 1.05 pu were reduced in the B.C. Hydro and PACE areas.

3.2.4 Line 3 Scheduled to Salt Lake City

In contrast to Line 2, no new rating violations occurred for Line 3 scheduled to Salt Lake City. Voltage violations in this case were minimal overvoltages in Canada and Goshen, Idaho located near Line 3 attachment points. Bus voltage at "GOSHEN" 161 kV went from 1.04 pu in the base case to1.06 pu, and voltage at "SWAN VAL" 161 kV increased from 1.05 pu to 1.06. These overvoltages can be resolved by fine-tuning transformer tap settings where Line 3 attaches to the existing system at buses Lethbridge 240 kV and at Kinport 345 kV, respectively.

A total of nine overvoltages in Canada were reduced by the Project. Of these, the largest per unit change in voltage (1.054 pu to 1.046 pu) occurred on Natal 138 kV located near the British Columbia - Alberta border.

3.2.5 Line 3 Scheduled to Lethbridge

Two existing 138 kV lines and one transformer in Alberta became overloaded with the introduction of the Project scheduled to Lethbridge. Table 3 summarizes the rating violations for this case.

Table 3 - Category A Rating Violations. Line 3 with Schedule to Lethbridge

Element Description	Rating [MVA]	Base Case Percent Loading	Scheduled Case Percent Loading
Transformer "848S901T" 240 kV to "RUTH LK4" 240 kV	100 MVA	90.0%	101.2%
Line "FOX CREE" 138 kV to "BENBOW 9" 138 kV	86 MVA	91.5%	100.5%
Line "METIS649" 138 kV to "KILRY TP" 138 kV	85 MVA	87.4%	100.5%

A significant number of buses crossed the overvoltage criteria threshold with the Project scheduled to Lethbridge. As can be seen in Table 2, 14 new voltage violations were introduced to the Alberta system, 19 were incurred in British Columbia, and 6 new voltage violations are present in the W. Kootenay area, all of which are overvoltages ranging from 1.05 pu to 1.07 pu. Of these, the worst overvoltage occurred on bus "KCL230" 230 kV in the B.C. Hydro area. The largest change in voltage (1.04 pu to 1.07 pu) occurred on bus "163ST2" 240 kV. A total of 34 other overvoltage violations were simultaneously fixed or reduced in Canada. The majority of the violation improvements were on 138 kV systems.

In the PACE area, one new overvoltage violation occurred on bus “SWAN VAL” 161 kV. The new voltage for bus “SWAN VAL” 161 kV is 1.06 pu. The violation also occurred for Line 3 when power was scheduled to Salt Lake City.

In the Northwest area, two voltage violations were fixed: an overvoltage on “WEED JPS” 115 kV was reduced from 1.05 pu to 1.04 pu, and an undervoltage on bus “OPORTUNE” 115 kV was raised from 0.949 pu to 0.950 pu.

3.3 Category B Violations

Table 4 introduces the number of violations affected by the project for Category B Power Flow. Approximately 1,915 single-outage contingencies were analyzed for each schedule. The number of contingencies varies based on which Project line is in service.

Note that Table 4 is relevant to continuous ratings (Rate 1).

Table 4 - Category B Violations Summary

Line Code	Schedule	Area Name	Violations caused or worsened by 5%		Violations fixed or improved by 5%	
			Ratings	Voltage	Ratings	Voltage
L1	Spokane	Northwest	29	49	1	-
		Montana	-	1	-	-
		WAPA U.M.	-	-	-	1
		WAPA R.M.	-	4	-	-
L2	Denver	Northwest	1	7	-	2
		Alberta	-	-	-	1
		Idaho	-	-	1	-
		Montana	-	15	3	-
		WAPA U.M.	-	1	-	-
		PACE	2	1	2	3
		Colorado	7	-	7	38
		WAPA R.M.	2	1	8	5
	Salt Lake City	Northwest	9	6	1	1
		Alberta	-	-	-	1
		Idaho	2	1	4	2
		Montana	3	22	3	4
		WAPA U.M.	-	3	-	-
		PACE	16	26	1	4
		Colorado	7	2	10	41
		WAPA R.M.	17	24	6	10
L3	Salt Lake City	Northwest	1	6	5	6
		Alberta	-	26	-	-
		Idaho	2	1	5	1
		Montana	5	14	-	4
		PACE	5	4	21	17
		WAPA R.M.	-	-	1	3
	Lethbridge	Northwest	-	3	20	10
		Alberta	5	-	2	1
		Idaho	1	1	3	1
		Montana	3	7	2	3
		PACE	5	-	21	20
		WAPA R.M.	2	3	2	10

3.3.1 Line 1 Scheduled to Spokane

For Line 1 scheduled to Spokane, the majority of violations occurred in the Northwest area. The most serious rating violation occurred on the Bell BPA 500 kV to Bell South 230 kV transformer (1220 MVA at Rate 1), which reached 149% of its rating for contingency Dworshak 500 kV to Taft 500 kV. This contingency is also responsible for most of the undervoltages created by the Project, including all 49 violations in the Northwest area. A 6% decrease in voltage was incurred on the Bell BPA 500 kV bus. The Northwest 115 kV system accounts for 47 undervoltage violations, ranging from 0.95 to 0.93 pu.

In comparison to the base case, two line outages did not converge for the schedule to Spokane. The first of these is the 500 kV line from Great Falls to Hot Springs which is a section of the Project Line 1. The system model did not converge when this line section was taken out of service indicating that it is a critical path for the Project generation at Great Falls. In other words, the surrounding system at Great Falls cannot support the transfer of the Project generation.

The second non-converging outage is a 230 kV line section from “BELL MI” to “BELL SO”. Line 1 introduces an additional 450 MW of power to the Bell 230 kV system where it is dispersed to meet the schedule. The “BELL MI” to BELL SO” line is an essential path for this new flow, carrying about 60% of the 450 MW. When the outage is taken the power flow must reroute through Beacon. In the base case, this outage causes 97% loading on two nearby 230-115 kV transformers at Beacon. A manual re-run of the outage indicates that these same transformers reach 126% of their continuous rating. Additionally, the 230 kV line from “BELL SO” to “BEACON N” becomes overloaded by 13%. Voltage values at Bell and Beacon are near their pre-contingency values.

3.3.2 Line 2 Scheduled to Denver

With the combination of Line 2 and the schedule to Denver, the influence of the Project appears to be widespread. New rating violations center around buses where Line 2 attaches to the existing system at Dave Johnston in Wyoming and at Daniels Park near Denver. The worst rating violation occurred for the Dave Johnston to Daniels Park 500 kV line outage, which is a section of Project Line 2. With this line out of service, loading reached 144% on an existing 230 kV line from Dave Johnston to Laramie River Station.

For contingencies near Daniels Park, a number of rating violations were caused by the Project indicating heavy loading of Daniels Park substation and nearby substations Waterton and Smoky Hill. The worst overload was on a 230-115 kV transformer at Waterton when an outage was taken on a parallel transformer. The remaining transformer reached 119% of its continuous rating (100 MVA).

Two contingencies did not converge for Line 2, and are both associated with the Project. A section of Line 2 from Colstrip to Dave Johnston, and the 500-230 kV transformer at Daniels Park are critical power flow paths for the Project.

The majority of voltage violations occur in Montana, as indicated in Table 4. They occur on the 115 kV, 161 kV, and 230 kV systems, and range from 0.92 pu to 0.95 pu. Eight of these undervoltages can be attributed to the outage on Line 2 from Great Falls 500 kV to Broadview 500 kV. The worst undervoltage caused by the Project was on bus “MT ASIMI” 161 kV at 0.92 pu for contingency Garrison 500-230 kV transformer.

Line 2 provides support for the 230 kV systems in Wyoming and Colorado as indicated by the improvements displayed in Table 4. The Colorado system and Western’s Rocky Mountain systems benefit from a reduction in rating violations during contingency conditions. The 500 kV line provides relief to surrounding

230 kV and 115 kV transmission lines due to its available capacity. The number of Category B undervoltage violations were also reduced, particularly in Colorado. A total of 37 undervoltages, slightly below 0.95 pu, on 230 kV buses were brought within 5% of nominal voltage.

3.3.3 Line 2 Scheduled to Salt Lake City

Table 4 shows extensive Category B violations for power flow scheduled to the Salt Lake City area. The introduction of contingencies magnifies the effect which the additional power flow has on the two primary transmission paths into Utah. As was discussed previously in Section 3.2.3, Line 2 has a negative impact on the Amps constraint in Idaho, and on the 345 kV transmission line across the Colorado-Utah border for a Salt Lake City schedule. According to the model, an outage on the Bonanza to Mona 345 kV line causes seven pre-Project rating violations which are made 12% to 27% worse by the Project, and introduces three new post-Project rating violations up to 104%.

The worst rating violations introduced by Line 2 scheduled to Salt Lake City occur on the 138 kV system in north-eastern Utah and north-western Colorado. Loadings of 100% to as high as 158% of ratings occurred for contingencies on nearby 345 kV lines. Most of the Category B voltage violations can also be attributed to 345 kV line outages, indicating that the system cannot support the additional power flow from Colorado to Utah during contingencies. In general, this case imposes additional strain on the Craig to Bonanza to Mona 345 kV transmission line.

Regardless of the schedule, the addition of Line 2 does improve system conditions in Colorado. Table 4 shows that a significant number of Category B rating and voltage violations were improved or eliminated in Colorado and Western's Rocky Mountain region.

3.3.4 Line 3 Scheduled to Salt Lake City

In comparison with Line 2, Line 3 presents fewer Category B violations when scheduled to Salt Lake City. Contingencies on Line 3 sections from Townsend to Dillon, and from Dillon to Kinport create severe rating violations on existing 161 kV transmission along the Anaconda-Dillon-Jefferson route due to the tie-in point at Dillon. A Line 3 connection to nearby Peterson Flats 230 kV bus instead of Dillon 161 kV would alleviate the overloads on the 161 kV system, but create similar albeit less severe problems on the 230 kV line from Anaconda to Peterson Flats to Amps.

Undervoltage conditions arise primarily in Alberta on 138 kV systems when the Line 3 outage from Great Falls to Lethbridge occurs. However, disconnecting the SVC located on the new 500 kV bus at Lethbridge restores previous levels. The majority of Category B undervoltage violations in Montana are minor; the worst being "MT ASIMI" 161 kV at 0.91 pu.

The most significant improvement brought about by Line 3 is evident during contingency Bonanza-Mona 345 kV. Seven rating violations and ten undervoltage violations are reduced or eliminated on the 138 kV system near the Utah-Colorado border.

3.3.5 Line 3 Scheduled to Lethbridge

Five new Category B rating violations occurred in Alberta on 138 kV and 240 kV lines as a result of Line 3 with schedule to Lethbridge. The most severe was 104% loading on "COALDAL9" 138 kV to "TABER A9" 138 kV, which is near Lethbridge. Rating violations also occurred in the PACE and Montana areas related to the Line 3 connection point at Dillon, as was discussed previously in Section 3.3.4.

The section of Line 3 from Great Falls to Lethbridge becomes a critical transmission path for the Project Generation, evidenced by the fact that the model fails to converge when an outage is taken on this line section. Note that contingency analysis was not run on systems in British Columbia and Alberta; however these facilities were monitored. The presence of Category A overloads in Canada, and the significant re-adjustment of power flows caused by the Project imply that additional Category B violations developed in Canada for this schedule.

One significant undervoltage violation occurred for this case. An undervoltage on the new 500 kV bus at Dillon exists for a Line 3 outage from Townsend to Dillon. Pre-contingency voltage is 1.07 pu on the Dillon 500 kV bus, versus 0.98 pu during the contingency. The pre-contingency voltage can be maintained by simultaneously adjusting the SVC on the Dillon 500 kV bus.

The number of Category B rating violations is widely reduced in the Northwest, PACE, and WAPA Rocky Mountain areas. The presence of Line 3 dampens the impact many contingencies would otherwise have on the system. For example, the model indicates that an overload on 161 kV line "FISHCREK" to "GOSHEN" in south-western Idaho occurs during 99 separate contingencies in the base case. Its worst-case loading is 117%. With the addition of Line 3, the worst-case loading on "FISHCREK" to "GOSHEN" is reduced by 10%, and the number of occurrences is also reduced from 99 to 4. Similar effects can be seen for other overloads in PACE and Northwest.

Many undervoltage conditions were also improved for Category B conditions. Line 3 helped to maintain pre-contingency voltage levels on several buses for contingencies on known constraint paths. Table 5 summarizes the voltage violations which were remedied in terms of existing constraints.

Table 5 - Correction of Category B Voltage Violations Near Constraint Paths

Constraint Path	Contingency	Worst Pre-Project Violation	Total Number of Voltage Violations Fixed by Project
Amps (Montana-Idaho border)	Antelope to Goshen 161 kV	0.94 pu on "AEC IPC" 138 kV	5
Yellowtail (Montana-Wyoming border)	"YELOWTLP" - "YELLOWBR" 230 kV	0.92 pu on "GREYBULL" 115 kV	6
Bonanza (Utah-Colorado border)	Bonanza - Mona 345 kV	0.93 pu on "EMMAPARK" 138 kV	10

4. DYNAMIC STABILITY ANALYSIS

4.1 Fault Scenarios

Seven fault locations were chosen for stability analysis and are described below. Each fault location listed was run on the indicated model corresponding to heavy flows through the location of the fault. Locations were chosen using engineering judgment based on a combination of proximity to the Project generators, magnitude of load interrupted, and dynamic response to contingencies on sections of the new transmission line options.

4.1.1 Fault Location 1

A three-phase fault was applied near the existing Great Falls 230 kV bus, and was cleared by tripping the 500-230 kV Project transformer at Great Falls after 5 cycles. Both pre- and post-Project faults scenarios were studied.

A single-circuit single-phase-to-ground fault near the existing Great Falls 230 kV bus was applied and subsequently cleared by tripping the 500-230 kV Project transformer at Great Falls after a delayed clearing time of 25 cycles. Both pre- and post-Project faults scenarios were studied. For the post-Project fault, Fort Peck Unit 1 was tripped at 25 cycles.

The post-Project fault scenarios at Location 1 were run on the Line 2 model scheduled to Denver, which models heavy flows to California and Denver (new flows to Denver due to the Project schedule), and moderate flows elsewhere (WECC Heavy Summer). Pre-Project fault scenarios were run on the corresponding base case model.

4.1.2 Fault Location 2

A single-circuit three-phase fault near the existing Garrison 500 kV bus was applied and subsequently cleared by tripping the Garrison-Taft 500 kV line after 3 cycles. Manual simulation of the Colstrip ATR was executed. Other events include:

- A reactor at Garrison 500 kV was tripped at 6.5 cycles.

- Reactors at Colstrip 230 kV and Broadview 230 kV were brought online at 5 seconds.

A single-circuit single-phase-to-ground fault near the existing Garrison 500 kV bus was applied and subsequently cleared by tripping the Garrison-Taft 500 kV line after a delayed clearing time of 9 cycles. Manual simulation of the Colstrip ATR was executed. Other events include:

- A reactor at Garrison 500 kV was tripped at 12.5 cycles.
- Reactors at Colstrip 230 kV and Broadview 230 kV were brought online at 5 seconds.

The post-Project faults at Location 2 were run on the Line 1 model scheduled to Spokane, which models heavy flows to the Northwest area (WECC Light Summer model), including the additional heavy flows introduced by the Project. Pre-Project fault scenarios were run on the corresponding base case model.

4.1.3 Fault Location 3

A single-circuit three-phase fault near the new Dave Johnston 500 kV bus was applied and subsequently cleared by tripping the Dave Johnston to Daniels Park 500 kV section of Line 2 after 3 cycles.

A single-circuit single-phase-to-ground fault near the new Dave Johnston 500 kV bus was applied and subsequently cleared by tripping the Dave Johnston-Daniels Park 500 kV section of Line 2 after a delayed clearing time of 9 cycles.

The post-Project faults at Location 3 were run on the Line 2 model scheduled to Denver, which is based on the WECC Heavy Summer model, and includes the additional heavy flows to Denver created by the Project. Pre-Project fault scenarios were run on the corresponding base case model.

4.1.4 Fault Location 4

A single-circuit three-phase fault near the new Great Falls 500 kV bus was applied and subsequently cleared by tripping the new 500-230 kV transformer at Great Falls after 3 cycles.

A single-circuit single-phase-to-ground fault near the new Great Falls 500 kV bus was applied and subsequently cleared by tripping the new 500-230 kV transformer at Great Falls after a delayed clearing time of 9 cycles.

The post-Project faults at Location 4 were run on the Line 2 model scheduled to Salt Lake City, which is based on the WECC Heavy Summer model, and includes the additional heavy flows to Salt Lake City created by the Project.

4.1.5 Fault Location 5

A single-circuit three-phase fault near the new Dillon 500 kV bus was applied and subsequently cleared by tripping the Dillon-Kinport 500 kV section of Line 3 after 3 cycles.

A single-circuit single-phase-to-ground fault near the new Dillon 500 kV bus was applied and subsequently cleared by tripping the Dillon-Kinport 500 kV section of Line 3 after a delayed clearing time of 9 cycles.

The post-Project faults at Location 5 were run on the Line 3 model scheduled to Salt Lake City, which is based on the WECC Heavy Summer model, and includes the additional heavy flows to Salt Lake City created by the Project.

4.1.6 Fault Location 6

A single-circuit three-phase fault near the new Kinport 500 kV bus was applied and subsequently cleared by tripping the new 500-345 kV transformer at Kinport after 3 cycles.

A single-circuit single-phase-to-ground fault near the new Kinport 500 kV bus was applied and subsequently cleared by tripping the new 500-345 kV transformer at Kinport after a delayed clearing time of 9 cycles.

The post-Project faults at Location 6 were run on the Line 3 model scheduled to Salt Lake City, which is based on the WECC Heavy Summer model, and includes the additional heavy flows to Salt Lake City created by the Project.

4.1.7 Fault Location 7

A single-circuit three-phase fault near the new Great Falls 500 kV bus was applied and subsequently cleared by tripping the Great Falls-Lethbridge 500 kV section of Line 3 after 3 cycles. Other events include:

- A reactor at Great Falls 500 kV was tripped at 6.5 cylces.
- A reactor at Lethbridge 500 kV was tripped at 6.5 cycles.

A single-circuit single-phase-to-ground fault near the new Great Falls 500 kV bus was applied and subsequently cleared by tripping the Great Falls-Lethbridge 500 kV section of Line 3 after a delayed clearing time of 9 cycles. Other events include:

- A reactor at Great Falls 500 kV was tripped at 6.5 cylces.
- A reactor at Lethbridge 500 kV was tripped at 6.5 cycles.

The post-Project faults at Location 7 were run on the Line 3 model scheduled to Lethbridge, which is based on the WECC Heavy Summer model, and includes the additional heavy flows to Lethbridge created by the Project.

4.2 Dynamic Stability Study Results

4.2.1 Fault Location 1

During initial runs, the Project was shown to have an adverse effect on the Fort Peck hydro generator. During the post-Project single-line-to-ground fault scenario, FT PECK1 became unstable. The fault scenario was rerun with the assumption that the FT PECK1 unit would trip. This was done in order to determine if additional system stability violations occurred with respect to the NERC/WECC criteria. This case does not meet stability criteria due to the fact that the Fort Peck hydro unit was adversely affected.

For the three-phase and single-line-to-ground faults, the system was shown to be stable (with the exception of FT PECK1). Post-fault voltages at Great Falls stabilized at new values which were only slightly less than their pre-fault values.

One voltage dip exceeding the 25% criteria for load buses was caused by the Project at FT PECK1 161 kV for the three-phase fault scenario. Voltage at FT PECK1 161 kV dipped from an initial value of 1.03 pu to 0.77 pu for a period of 2 cycles. Due to the short duration of this violation, it is not likely to result in any voltage violations on load buses at or near Fort Peck. Three voltage dips exceeding the 30% criteria and one exceeding the 25% load bus criteria appear to have been corrected by the Project for the single-line-to-ground case; however they are likely the result of tripping FT PECK1 in the post-Project case. The worst of these voltage dips occurred on the FT PECK1 13.8 kV bus, which dipped from a pre-fault value of 1.03 pu to 0.67 pu for 18 cycles.

4.2.2 Fault Location 2

The system was observed to be transiently stable for all fault scenarios, both pre- and post-Project. No transient voltage violations occurred for any of the fault scenarios at Location 2; however, post-transient voltage at Townsend exceeded 5% of its initial value for the post-Project case. This result was observed in both the pre- and post-Project scenarios, but is not consistent with historical data for the 500 kV system.

The number of frequency dips exceeding criteria was reduced by the Project. The worst pre-Project frequency dip to 59.32 Hz at FT PECK1 13.8 kV was improved to 59.45 Hz.

This case does not meet the post-transient voltage deviation criteria, which requires all buses to settle within 5% of their initial voltage levels. A shunt reactor (in addition to the existing 96 MVAR) at the Broadview 500 kV bus may be necessary to maintain post-transient voltage following a disturbance.

4.2.3 Fault Location 3

Fault scenarios at the new Dave Johnston 500 kV bus introduced minor disturbances to the system, resulting in stability in Montana, Wyoming, and Colorado. No transient events exceeding criteria were observed. Post-transient voltage levels on Daniels Park 500 kV were down by approximately 4%, but do not constitute a violation of voltage criteria. This case meets all key stability criteria.

4.2.4 Fault Location 4

Fault scenarios run at Location 4 were all observed to be stable. No transient or post-transient criteria violations occurred for either the three-phase or the single-line-to-ground cases. This case meets all key stability criteria.

4.2.5 Fault Location 5

Fault scenarios run at Location 5 were all observed to be stable. No transient or post-transient criteria violations occurred for either the three-phase or the single-line-to-ground cases. This case meets all key stability criteria.

4.2.6 Fault Location 6

All fault scenarios at Location 6 were observed to be stable. No transient criteria violations occurred for either the three-phase or the single-line-to-ground cases. Post-transient voltages on the Dillon 500 kV bus and the Dillon 161 kV bus experienced a 6% increase over initial levels. The 6% increase is a violation of the post-transient voltage deviation criteria. Recognizing that the SVC located on the new Dillon 500 kV bus does not sink any reactive power in the steady state model, refining this device's control settings may correct this post-transient voltage deviation.

4.2.7 Fault Location 7

Faults at Location 7 resulted in instability on systems in Canada. Following the clearing of the Great Falls-Lethbridge 500 kV line, voltage collapse was observed on systems across British Columbia and Alberta. Several undervoltage and underfrequency relays operated to trip lines and reduce load. The Colstrip ATR operated as well. The following events occurred after the three-phase fault.

- The Colstrip ATR operated to trip the Miles City DC tie approximately 11 cycles after the fault cleared.
- A 138 kV line at Natal, B.C. (NTL VR to NTL138) opened approximately 1.3 seconds after the fault was cleared.
- A 500 kV line from Cranbrook, B.C. to Langdon, Alberta (CBK500 to LANGDON2) opened approximately 1.5 seconds after the fault was cleared.
- The Colstrip ATR operated to trip Colstrip Unit 2 (operating at 330 MW) approximately 3.2 seconds after the fault was cleared.
- The Colstrip ATR operated to trip Colstrip Unit 1 (operating at 330 MW) approximately 3.3 seconds after the fault was cleared.
- Load shedding schemes operated at three locations (FRO138, LCC138, GRH138) in the B.C. Hydro area between 3.4 to 3.8 seconds after the fault cleared.

Events were similar but generally less severe for the single-line-to-ground fault. The Colstrip ATR refrained from operating, but the 138 kV line and the 500 kV line in B.C. opened. The same three load shedding schemes operated as well.

Frequency dropped to 58.56 Hz at Lethbridge shortly after the Cranbrook-Langdon 500 kV line opened, and did not fully recover within the 10 second simulation time.

It is readily apparent that the new Great Falls to Lethbridge 500 kV tie becomes a critical link for the Alberta system when heavy transfers exist along this line. The Project model scheduled to Lethbridge indicates that Alberta requires a net import of 1400 MW. Only one 500 kV transmission line from Cranbrook to Langdon provides for power imports from B.C. to Alberta. When the Great Falls-Lethbridge section of Line 3 is suddenly taken out of service, its pre-contingency power flows must be made up either by increased flows through the Cranbrook-Langdon line, or by machines on the Alberta system. For significant transfers from Montana to Alberta, VAR margins are inadequate to support additional flows on the Cranbrook-Langdon 500 kV line, and the response of machines in Alberta is too gradual to prevent system collapse.

This case does not meet stability criteria due to the cascading effect of the contingency, and the voltage collapse observed on the Alberta system.

5. COST ANALYSIS

Transmission and substation estimated costs for the individual studies are as shown in Table 6. The generation substations do not include any distribution equipment. The estimated costs began at the low side bushings of the GSU transformer and went through to the designated transmission tie-in buses.

Table 6 - Cost Analysis by Project Line

Line Code	Substation Cost (thousands)	Transmission Costs (thousands)	Total Costs (thousands)
L1	$60,213	$202,981	$263,194
L2	$115,147	$381,606	$496,753
L3	$137,373	$428,683	$566,056

Line 1 represents the least in cost of the Project lines estimated at $263 million. The realization of Line 3 is most expensive at $566 million.

6. VIABILITY ANALYSIS

The feasibility of each transmission line alternative was ascertained given the results of the power flow and dynamic stability analyses. Transmission line options which are considered viable were shown to be acceptable in terms of Category A and dynamic stability criteria.

Appropriate project refinements and the mitigation of noted Category B contingencies is expected to be performed with any further project development. Table 7 presents the transmission line options in terms of their viability. A contingency summary table can be found in the appendices for each of the cases determined to be viable.

Table 7 - Viability Summary

Project	Line Code: Description	Schedule	Comments	Viable Project?
Project 2 1000 MW Gas near Great Falls	**L1: 500 kV to Spokane**	Spokane	Slight overvoltages can be corrected by adjusting transformer taps.	**Yes**
	L2: 500 kV to Denver	Denver	Instability at Fort Peck hydro Unit 1	No
		Salt Lake City	Overloads: 161 kV Jefferson Phase transformer; Bonanza-Mona 345 kV (known constraints)	No
	L3: 500 kV Lethbridge to Salt Lake City	Salt Lake City	Slight overvoltages can likely be corrected by adjusting transformer tap.	**Yes**
		Lethbridge	Alberta Voltage collapse during contingency.	No

The viable transmission alternatives, as shown in Table 7, are Line 1 routed to Spokane and Line 3 routed and scheduled to Salt Lake City. Both of these cases met stability and Category A criteria with the exception of minor overvoltages which could likely be corrected by adjusting appropriate transformer taps near the affected buses.

Line 2 scheduled to Denver did not meet stability criteria for a fault scenario on the Great Falls 230 kV bus due to the fact that the Fort Peck Unit 1 hydro generator became unstable. The same line with generation scheduled to Salt Lake City did not provide sufficient transfers to Salt Lake City due to Category A overloads on existing constraint paths.

Although Line 3 provided a good transfer path to Lethbridge, stability analysis indicated voltage collapse and subsequent islanding of the Alberta system from British Columbia when the Line 3 Great Falls-Lethbridge section was faulted and removed from service. The conditions experienced during this outage do not meet criteria.

7. CONCLUSIONS

The 1000 MW generation facility located at Great Falls presents specific advantages and disadvantages to exporting power from Montana. In general, the presence of the Project lines provides offloading to adjoining facilities, especially during contingencies in constraint areas. However, the additional power flows created adverse loading conditions in the areas of intended export and along the transmission path for contingencies on the Project line sections.

Substations near load centers, specifically at Bell Substation near Spokane, and at Daniels Park Substation near Denver were observed to be strained due to the Project. Transmission improvements outlined in the Contingency Analysis Summaries (found in the appendices) may be necessary for the two viable Projects in addition to the radial transmission routes.

Despite the additional capacity provided by the new lines, the Project created additional stress on existing export constraints. Line 1 and the corresponding schedule to Spokane caused numerous Category B violations in the Northwest area, the most severe of which occurred near the Bell Substation. The mitigation of these contingency violations would make this a viable transmission alternative.

Line 2 created both Category A and Category B violations on the 161 kV Montana-PACE interface from Dillon to Big Grassy. For schedules to Salt Lake City (both Line 2 and Line 3) the 230 kV Amps constraint and the adjacent 161 kV path suffered Category B rating violations. Line 2 was most advantageous for the 230 kV systems in Wyoming and Colorado regardless of the schedule. Category B rating violations were reduced in Colorado and Western's Rocky Mountain region. The Montana system was also observed to benefit from Line 2 in terms of increased dynamic stability.

Improved performance was provided by Line 3 for the 161 kV system near Bonanza, Utah. The severity of violations was reduced for the Bonanza-Mona 345 kV contingency. Faults along the route of Line 3 caused minimal disturbances to the system during stability analysis. This is a viable transmission option.

Although the schedule to Lethbridge provided improved voltage levels near the Amps, Yellowtail, and Bonanza constraints, dependence on the Great Falls-Lethbridge tie was demonstrated by dynamic stability analysis. Voltage collapse and severe frequency dips were observed on the Alberta system for faults on the Great Falls-Lethbridge 500 kV section of Line 3. Line 3 is not viable for a 1000 MW schedule to Lethbridge due to system instability.