Montana – Dakotas
Regional Transmission Study

WEST SIDE STUDIES
PROJECT 3

Western
AREA POWER
ADMINISTRATION

UPPER GREAT PLAINS REGION
Transmission Planning

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PROJECT 3 SUMMARY

Project 3 modeled a 500 megawatt (MW) thermal generator installed near Billings, Montana. This project evaluated three different transmission line alternatives and six different power flow schedules to find their individual impacts on the power system.

The first transmission line alternative, referred to as Line 1, was a new 500 kV transmission line from Billings, Montana to Great Falls, Montana to Spokane, Washington; and a new 230 kV transmission line was added from Shelby, Montana to North Lethbridge, Alberta. With these line improvements in place, the power flow was scheduled separately to Spokane, Salt Lake City, and Lethbridge. For this transmission alternative it was shown that power scheduled to Spokane introduced the least amount of new violations, and power scheduled to the Lethbridge area introduced the most new violations.

The second transmission line alternative, referred to as Line 2, was a new 500 kV transmission line from Billings to Denver, Colorado; and with this line in place, the power flow was scheduled to Denver and Salt Lake City. For this transmission alternative it was shown that power scheduled to Denver introduced the least amount of new violations, and power scheduled to the Salt Lake City area introduced the most new violations.

The third transmission line alternative, referred to as Line 3, was a new 500 kV transmission line from Billings to Salt Lake City. With this line in place, the power flow was scheduled to Salt Lake City. For this transmission alternative it was shown that, as expected, there were very few new violations.

The estimated cost for each transmission line alternative studied was $343 million for Line 2, $391 million for Line 3, and $414 million for Line 1. Each transmission option was shown to be viable for its intended market. System intact and stability was acceptable for these line options and corresponding schedules.

Table 5 summarizes the conclusions on feasibility of each transmission alternative and schedule. Contingencies that were impacted by the Project are summarized in the appendices for the viable alternatives. Two of the viable alternatives that are the line to Spokane and the line to Denver indicate localized impacts at the delivery point during contingencies. The third viable alternative shows that the impact is mainly on the existing 161 kV constraint adjacent to Amps. Recommendations for mitigation are included in the contingency summaries and would need to be addressed during project development.

1. INTRODUCTION AND PROJECT SCOPE

Project 3 of the Montana Transmission Study investigated the effects of a 500 MW thermal power plant near Billings, Montana. Several 230 kV and/or 500 kV transmission line routes to deliver power to remote load centers were considered.

1.1 Scope

The Project simulated a 500 MW thermal generation facility located within 40 miles of Billings. A 40 mile 500 kV single circuit tap tied the new generation to a new 500 kV bus at Billings. This new bus tied to the existing Billings 230 kV bus via a transformer. The following transmission alternatives were investigated with corresponding load flow schedules. For this Project, the 500 MW thermal facility was modeled as one 500 MW generator. For the purpose of discussion, each transmission alternative is referred to as "Line 1", "Line 2", and "Line 3" hereafter.

Line 1: 500 kV line from Billings, Montana to Spokane, Washington; 230 kV line from Shelby to North Lethbridge.

- Scheduled to Spokane
- Scheduled to Salt Lake City
- Scheduled to Lethbridge

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

- Scheduled to Denver
- Scheduled to Salt Lake City

Line 3: 500 kV line from Billing, Montana to Salt Lake City, Utah

- Scheduled to Salt Lake City

Project maps illustrating the line routing for each of the transmission alternatives can be found in the Appendices. Figure 1 shows the line routing for Line 1. From the new Billings 500 kV bus the new 500 kV transmission line was connected to the existing Broadview 500 kV bus. A new 500 kV transmission line is connected from the existing Broadview 500 kV bus to the new 500 kV Great Falls bus. A new 500 kV transmission line connects from Great Falls to the existing 500 kV Hot Springs bus. From Hot Springs a new 500 kV line connects to the existing Bell 500 kV bus. A 230 kV line was added from Shelby to North Lethbridge and tied to the existing 230 kV bus at Shelby and the new 230 kV bus at Lethbridge. At the existing 230 kV Great Falls and Billings buses, transformers were added in order to connect the new buses to the existing system, and a transformer was added from the new 230 kV Lethbridge bus to the existing 138 kV North Lethbridge bus.

Figure 2 shows the studied line route for Line 2. From a new 500 kV Billings bus, the new 500 kV transmission line was connected to a new 500 kV bus at Dave Johnston, and from Dave Johnston to a new 500 kV bus at Daniels Park. A 500 kV to 230 kV transformer was added at Dave Johnston as well as at Daniels Park in order to connect to the existing system.

Figure 3 shows the studied line route for Line 3. From the new 500 kV Billings bus the new 500 kV transmission line was connected to a new 500 kV bus at Dillon, to a new 500 kV bus at Kinport, and to a new 500 kV bus at Ben Lomond. Transformers were added at the existing 345 kV Kinport, 345 kV Ben Lomond, and 161 kV Dillon South buses in order to the connect the new buses to the existing system.

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 areas.

2.1 Line 1 Scheduled to Spokane

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

Static VAR Compensators (SVC's) were added at the new Great Falls 500 kV and Lethbridge 230 kV buses to counteract excessive voltage rise due to the line charging of the added transmission lines. SVC's were also added to the existing Hot Springs and Broadview 500 kV buses.

Area schedules were modified to reflect the additional exports from Montana to the Northwest Area. The swing generators in each of the areas experienced small changes in their swing megawatts. A total schedule of 491 MW was achieved with minimal effect on the swing generators.

2.2 Line 1 Scheduled to Salt Lake City

The Salt Lake City Line 1 model simulates 500 MW of new generation scheduled to Salt Lake City with Line 1 in service. It is based on the WECC 2002 Heavy Summer model. A total schedule of 477 MW was achieved with minimal effect on the swing generators. SVC's were added at the new Great Falls 500 kV bus, the new Lethbridge 230 kV bus, and the existing Hot Springs and Broadview 500 kV buses to maintain appropriate voltage levels.

2.3 Line 1 Scheduled to Lethbridge

The Lethbridge Line 1 model represents the Project generator scheduled to the North Lethbridge area and is based on the WECC 2002 Heavy Summer model. A total schedule of 484 MW was achieved with minimal effect on the swing generators. SVC's were added at the new Great Falls 500 kV bus, the new Lethbridge 230 kV bus, and the existing Hot Springs and Broadview 500 kV buses to maintain appropriate voltage levels.

2.4 Line 2 Scheduled to Denver

Line 2 scheduled to Denver is based on the WECC 2002 Heavy Summer model. The swing generator in Montana experienced minimal changes in swing megawatts. A total schedule of 491 MW was achieved with minimal effect on the swing generators. SVC's were added on the new Billings 500 kV and Dave Johnston 500 kV buses to maintain appropriate voltage levels.

2.5 Line 2 Scheduled to Salt Lake City

For this case based on the WECC 2002 Heavy Summer model, the new generation was scheduled to Salt Lake City with Line 2 to Denver in service. A total schedule of 484 MW was achieved with minimal effect on the swing generators. SVC's were added on the new Billings 500 kV and Dave Johnston 500 kV buses to maintain appropriate voltage levels.

2.6 Line 3 Scheduled to Salt Lake City

The next model represents the Project generation scheduled to Salt Lake City with Line 3 to Salt Lake City in service. The Salt Lake City Line 3 model is based on the WECC 2002 Heavy Summer model. A total schedule of 483 MW was achieved with minimal effect on the swing generators. SVC's were added at the new Dillon and Kinport 500 kV buses to maintain appropriate voltage levels.

3. POWER FLOW ANALYSIS

Two power flow conditions were studied: Category A and Category B. The effect of the Project on the system 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 power has been scheduled.

Table 1 - Project Effect on System Losses by Area

Line Code-->	L1		L1		L1		L2		L2		L3	
Schedule	Spokane		Salt Lake City		Lethbridge		Denver		Salt Lake City		Salt Lake City	
	MW	MVAR	MW	MVAR	MW	MVAR	MW	MVAR	MW	MVAR	MW	MVAR
Total System	42	-736	115	-156	-4	-1277	-41	-1442	16	-982	-65	-1717
Northwest	**27**	**-467**	51	-84	-14	-943	-6	-80	4	31	-26	-383
B.C. Hydro	4	43	4	44	5	79	0	6	1	9	-1	-7
Alberta	1	-19	0	-38	**-19**	**-220**	0	0	0	0	0	0
Idaho	2	14	4	-1	2	18	-2	-14	5	34	-10	-47
Montana	7	-321	21	-248	15	-273	8	-453	13	-415	15	-580
WAPA U.M.	0	0	1	16	0	5	0	3	-1	-3	-1	-17
PACE	0	8	**27**	**116**	4	36	-2	6	**27**	**209**	**-39**	**-659**
Colorado	0	1	0	-3	0	1	**-24**	**-796**	-30	-868	0	-1
WAPA R.M.	0	9	9	53	3	22	-14	-112	-3	25	-2	-16

The effect of the Project on system 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 for this Project occurred for Line 1 scheduled to Salt Lake City. The most beneficial change overall occurred for Line 3 scheduled to Salt Lake City where the off-loading of existing lines due to an improved flow path caused by Line 3 resulted in a 39 MW reduction of losses in the PACE area. The overall reduction in real power losses was approximately 65 MW.

Throughout Table 1 there are large reductions in reactive power losses (MVARs). These decreases are the result of line charging of the added transmission lines.

As can be expected, significant changes occur in the Montana export area and the import area (values in bold). For each schedule, however, due to the physical power flow paths, the Project can be seen to also have some impact on surrounding areas. This is particularly evident for Line 1 scheduled to Salt Lake City. Because Line 1 does not route directly to the Salt Lake City area, a significant amount of the additional imports must come from other transmission paths and sources.

3.2 Category A Violations

Table 2 presents the number of Category A rating and voltage violations for 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	1
		Alberta	-	-	-	6

		Montana	-	-	-	1
		Sierra	-	1	-	-
	Salt Lake City	Northwest	-	-	-	1
		B.C. Hydro	-	-	-	6
		Alberta	-	-	-	1
		Montana	-	4	-	1
		PACE	3	2	-	2
		WAPA R.M.	-	1	-	-
	Lethbridge	Northwest	-	-	-	2
		B.C. Hydro	-	18	-	1
		Alberta	1	12	1	23
		Montana	-	1	-	1
		W. Kootenay	-	3	-	-
L2	Denver	Montana	-	-	-	1
		PACE	-	-	-	1
	Salt Lake City	Northwest	-	-	-	2
		B.C. Hydro	-	-	-	2
		Montana	-	-	-	1
		PACE	2	-	-	2
L3	Salt Lake City	PACE	-	1	-	-

3.2.1 Line 1 Scheduled to Spokane

As can be seen in Table 2, only one new voltage violation and no new rating violations occurred for this case. This is not unexpected, since the added transmission line routes directly from Billings to the Spokane area, and the new transmission line mostly carries the additional generation.

The addition of Line 1 to Spokane also fixed 3 rating violations. The two "CHIEFJO" Generator Step-Up (GSU) transformers, and the "COUGAR T" GSU experience 4% and 3% decreases respectively in their loading. This decrease is due to a reduction of generator output due to the scheduling method, and cannot be considered an improvement brought about by the Project.

There were 8 voltage violations fixed compared to base case power flows. All were minor overvoltages, with 6 of them in the ALBERTA area. The new transmission line to Lethbridge would be expected to improve bus voltages in the ALBERTA area.

3.2.2 Line 1 Scheduled to Salt Lake City

The three new rating violations caused by the Line 1 schedule to Salt Lake City are in the known constraint area around Amps in Idaho. The 161 kV phase-shifting transformer at Jefferson reached 112% of its rating, and two 161 kV lines out of Fish Creek reached 109% and 106%, respectively.

For Line 1 scheduled to Salt Lake City, seven voltage violations were caused and 11 violations were fixed. The 11 voltage violations that were fixed were all very minor overvoltages. Four of the seven voltage violations that were caused occurred in the Montana area and all were undervoltage violations, with the worst

violation at PTRSNFLT 230 at 0.930 per unit. Most of the new voltage violations for this case are in the Montana area.

3.2.3 Line 1 Scheduled to Lethbridge

For this case, Table 2 shows one new rating violation, which occurred in the ALBERTA area. The new rating violation in Alberta occurred on the RED DEE9 138 kV to 240 kV transformer which became113.2% overloaded. One rating violation occurring in the base case was fixed with the new line in place, also in the Alberta area.

Line 1 scheduled to Lethbridge caused a total of 34 new overvoltage violations, 30 of which were in Alberta and British Columbia. Line 1 also fixed 27 undervoltage and overvoltage violations for this scenario, 24 of which were in Alberta and British Columbia. Further investigation into the system model indicates that all but one of the overvoltage violations were just above 1.05 per unit and represent small percentage changes of less that one half percent over the base model values. The majority of voltage violations that were fixed were only slightly above voltage criteria limits, and were fixed by very small percentage changes.

3.2.4 Line 2 Scheduled to Denver

As can be seen in Table 2, no new rating or voltage violations occurred for this case. This is not unexpected, since the added transmission line goes directly to the Denver area, and the new transmission line mostly carries the increased power flow.

Line 2 scheduled to Denver corrected two very minor overvoltages that occurred in the base case in the MONTANA area.

3.2.5 Line 2 Scheduled to Salt Lake City

There were two new rating violations. The Fish Creek to Goshen 161 kV line reached 102% of its rating, but this line is in the known Amps constraint area in Idaho. The 345 kV line from Bonanza to Mona line became loaded to 113% in the system model. This overload may be explained by the power being scheduled to the Salt Lake City area with no new direct transmission paths.

Line 2 scheduled to Salt Lake City did not cause any new voltage violations, and fixed seven voltage violations that existed without the line in place. Two minor undervoltages at OPORTUNE 115 kV and IRVIN 115 kV were fixed in the Northwest area . Slight overvoltages near the 1.05 pu criteria threshold were slightly reduced on two 345 kV buses at Pinto, one 115 kV bus in Montana, and two buses in British Columbia.

3.2.6 Line 3 Scheduled to Salt Lake City

No new rating violations were caused by Line 3. There was one new voltage violation at the 161 kV Swan Valley bus, which was a slight overvoltage. Line 3 scheduled to Salt Lake City did not fix any rating or voltage violations.

3.3 Category B Violations

Table 3 shows the number of rating and voltage violations affected by the Project for Category B Power Flow. For Line 1 to Spokane, 1,900 single-outage contingencies were analyzed (Light Summer model), and 1,913 single-outage contingencies were analyzed for all other cases (Heavy Summer model).

Note that Table 3 is only relevant to continuous ratings (Rate 1).

Table 3 - 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	12	8	-	1
		Alberta	-	1	-	-
		Montana	1	4	-	1
		WAPA R.M.	-	3	-	-
	Salt Lake City	Northwest	11	39	3	1
		Alberta	-	1	-	-
		Idaho	4	1	1	-
		Montana	3	15	-	6
		WAPA U.M.	-	1	-	-
		PACE	21	10	8	2
		WAPA R.M.	8	4	4	4
	Lethbridge	Northwest	6	10	12	3
		Alberta	3	-	-	-
		Montana	-	6	-	-
		PACE	1	-	-	-
		WAPA R.M.	2	1	1	-
L2	Denver	Northwest	1	6	2	2
		Montana	-	7	-	-
		PACE	2	2	2	1
		Colorado	4	1	12	41
		WAPA R.M.	3	2	9	4
	Salt Lake City	Northwest	1	7	10	-
		Idaho	-	1	-	1
		Montana	2	7	-	2
		PACE	21	13	-	1
		Colorado	5	2	-	41
		WAPA R.M.	11	26	7	7
L3	Salt Lake City	Northwest	1	5	5	5
		Idaho	2	1	4	1
		Montana	2	24	-	-

		PACE	5	2	20	18
		WAPA R.M.	-	-	2	4

3.3.1 Line 1 Scheduled to Spokane

For Line 1 scheduled to Spokane,12 rating violations occurred in the Northwest area. The most serious new rating violation occurred on the BELL BPA 500 kV to BELL SO 230 kV transformer which reached 127% of its rating for the Dworshak to Taft 500 kV line contingency.

Five of the sixteen voltage violations introduced by this scenario occurred during an outage on the new Lethbridge 230-138 kV transformer. The most severe of these undervoltage violations occurred in Alberta at the new Lethbridge 230 kV that dropped to 0.847 per unit. The Lethbridge 230 kV bus no longer had the voltage support of the autotransformer during this contingency.

The eight new voltage violations in the Northwest area are due to contingencies with Dworshak to Hatwai 500 kV and Dworshak to Taft 500 kV line outages. The worst undervoltage is 0.94 per unit occurring at four separate buses. An overall observation of the results for the Line 1 scheduled to Spokane is that there are few new Category B rating violations.

This case had one new non-converged outage: Broadview to Great Falls 500 kV, which is a section of the new transmission line of this option. Revisiting this outage indicated that the Colstrip Unit 4 GSU reached 102% of its continuous rating. Simultaneously tripping the SVC located on the new Great Falls 500 kV bus reduces the overload to 101%, which the transformer should be able to carry for a short time.

3.3.2 Line 1 Scheduled to Salt Lake City

For Line 1 scheduled to Salt Lake City, of the 47 new Category B rating violations, 21 occurred mainly in PACE, 11 occurred in the Northwest area, and 8 occurred in the WAPA R.M. area. This case caused 70 new Category B voltage violations in the model: 39 violations in the Northwest area, 15 in the Montana area, and 10 in the PACE area . The most severe new rating violation occurred on the Antelope to Goshen 161 kV line which reached 121% of its rating for the Anaconda-Peterson Flats 230 kV line contingency. Further investigation shows that the majority of the new rating violations occur around the known Amps constraint area in Idaho or along the eastern Utah border.

The most severe voltage violation occurred at AEC IPC 138 kV with an undervoltage of 0.748 per unit for the Anaconda-Peterson Flats 230 kV line outage. This particular outage produced large undervoltages for five buses.

There was one new outage that did not converge for this case: Amps to Antelope 230 kV. The non-convergence of this contingency on a constraint path indicates an undesirable increase in loading on the existing transfer. The

transmission line to Spokane does not provide acceptable performance for the Salt Lake City market.

3.3.3 Line 1 Scheduled to Lethbridge

For Line 1 scheduled to Lethbridge, six of the 12 new rating violations were in the Northwest area, and three were in the PACE area. The location of the rating violations indicate that the new generation at Billings is not supplying sufficient power to North Lethbridge. The addition of a phase shifting transformer to the new Shelby-Lethbridge 230 kV transmission line would improve the flow along this path. However, stability issues, as was shown in Project 2 stability analysis of a new Great Falls to Lethbridge 500 kV line would limit transfers.

The most serious new voltage violation occurred at Irvin 115 kV, which reached undervoltage of 0.865 per unit. An overall observation of the results for the Line 1 scheduled to Lethbridge is that more new Category B rating violations occurred than were fixed.

3.3.4 Line 2 Scheduled to Denver

Ten new rating violations occurred for Line 2 scheduled to Denver. The most severe rating violations were of the two Waterton 115-230 kV transformers that increased from 116% to 122% overloaded.

The most severe voltage violation occurred in Montana area at the Shelby 115 kV bus, which dropped to 0.94 per unit for the Great Falls 230 kV to Bole 230 kV contingency.

For Line 2 scheduled to Denver, 28 Category B violations were caused or worsened by the Project whereas 73 were shown to be fixed or improved. The net effect indicates that Line 2 scheduled to Denver has a desirable impact on the system. This result is not unexpected, since the added 500 kV transmission lines connect Billings to the Denver area, and the new lines would support the increased power flow.

This case had one new outage that failed to converge. The outage was on the new Daniel Park 500-230 kV transformer, and indicates that additional or redundant transmission ties to the PSCOLORADO grid would be desirable from a reliability standpoint.

3.3.5 Line 2 Scheduled to Salt Lake City

For Line 2 scheduled to Salt Lake City, most new rating and voltage violations occurred in the PACE and WAPA R.M. areas. The most serious new rating violation was on the Artesia to Hayden 138 kV line which reached 145% of its rating for the Bears to Bonanza 345 kV line contingency. The most severe voltage violation occurred in the Northwest area at the Irvin 115 kV bus, which dropped to 0.867 per unit for the PLUMMER to OGARA 115 kV contingency.

Although 67 Category B rating and voltage violations were fixed or improved in the Colorado and WAPA R.M. areas due to the new Line 2 Project, 48 violations were caused or worsened in the PACE area. The majority of the rating and voltage violations occurred during contingencies on the 345 kV line that traverses the Colorado-Utah border. This is an indication that Line 2 is not the preferred Project when power is scheduled to Salt Lake City. Another observation is the desirable impact on the Colorado area when Line 2 is installed, even if power is not scheduled to Denver.

There were two new outages that did not converge for this case. The two new outages were EMMAPARK to UPALCO 138 kV, and Bears to Craig 345 kV. This transmission line options is not the preferred alternative for scheduling the new generation to Salt Lake City due to the heavy dependence of the existing 345 kV system in western Colorado and eastern Utah.

3.3.6 Line 3 Scheduled to Salt Lake City

Ten rating violations were caused or worsened by the Project with Line 3 in service. Six of these were in the Montana area for contingencies involving outages on the new transmission lines or transformers. The worst rating violation occurred on the Jefferson 161 kV phase shifting transformer which reached 191% of its 100 MVA rating for the contingency outage of the Project's Kinport-Dillon 500 kV transmission line. The rating violation on the Jefferson phase shifting transformer represents an incremental increase of 74% over the pre-Project case. This indicates that the Project transmission lines are critical for scheduling the new generation to the Salt Lake City area.

Contingencies on the Bonanza-Mona constraint were shown to be less severe due to the additional transmission support provided by this line option. Fourteen rating violations were improved by 10% to 20% over the pre-Project contingency. Most of these improvements occurred in the PACE area on the 138 kV system near the Colorado-Utah border. Seventeen rating violations were shown to be brought within criteria by the Project. Most of these were originally only slightly overrated.

There were 32 new and worsened voltage violations, 19 of these were caused by the Project's contingency outage of the new Billings-Dillon 500 kV transmission line. Almost all of the other violations were very slight undervoltages. There were 28 voltage violations that were improved or corrected. The majority of the improvements were in the PACE area.

There was one new outage that failed to converge. The non-converged outage occurred on the Billings 500-230 kV transformer, indicating that this is a critical contingency for the new Project generation.

4. DYNAMIC STABILITY ANALYSIS

4.1 Fault Scenarios

The dynamic stability of the power system was studied for both a three-phase fault and a single-line to ground fault applied to six different buses. 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.

When the fault is applied to an existing bus in the system, the effect of the Project on the system is gauged by comparing pre-Project and post-Project dynamic responses to the disturbance. When the fault is applied to a new bus added to the system by the Project, there is no pre-Project information available, and the effect of the Project is measured by inspecting the post-Project dynamic responses to the disturbance.

The six fault locations chosen for stability analysis are described below:

4.1.1 Fault Location 1

Faults (pre- and post-Project, and both 3-phase and single-line-to-ground) were selected to be applied near the new MTSBLGS1 500 kV bus that was added by the Project at Billings. The model used for this simulation is Line 1 with power scheduled to Spokane that had heavy power flows through the region of the fault (WECC Light Summer model). The pre-Project scenarios were run on the corresponding base case model. Manual simulation of the Colstrip ATR was executed for the post-Project single-line-to-ground fault.

After the duration of the fault, the new 500 kV transmission line from MTSBLGS1 to MTSBLGS2 was dropped to clear the fault. Tripping the faulted line in a normal 3 cycle clearing time cleared the three-phase fault. The single-line-to-ground fault was cleared by tripping the faulted line in a normal 9 cycle clearing time.

The tripping of the 500-kV transmission line had the effect of tripping off the 500 MW of new generation for this scenario.

4.1.2 Fault Location 2

Faults (pre- and post-Project, and both 3-phase and single-line-to-ground) were selected to be applied to the existing GARRISON 500 kV bus. The model used for this simulation is Line 1 with power scheduled to Spokane which had heavy power flows through the region of the fault (WECC Light summer model). The pre-Project scenarios were run on the corresponding base case model. Manual simulation of the Colstrip ATR was executed for the pre-Project 3-phase and single-line-to-ground faults, and the post-Project single-line-to-ground fault.

After the duration of the fault, the existing 500 kV line from GARRISON 500 kV to TAFT 500 kV was dropped to clear the fault. The three-phase fault was cleared by tripping the faulted line in a normal 3 cycle clearing time. The single-line-to-ground fault was cleared by tripping the faulted line in a normal 9 cycle clearing time.

4.1.3 Fault Location 3

Faults (post-Project, and both 3-phase and single-line-to-ground) were selected to be applied the new MTSBLGS1 500 kV bus that was added by the Project at Billings. The model used for this simulation is Line 2 with power scheduled to Denver that had heavy power flows through the region of the fault (WECC Heavy Summer model). Manual simulation of the Colstrip ATR was executed for the post-Project 3-phase fault.

After the duration of the fault, the new 500 kV transmission line from MTSDAVEJ to MTSBLGS1 500 kV was dropped to clear the fault. The three-phase fault was cleared by tripping the faulted line in a normal 3 cycle clearing time. The single-line-to-ground fault was cleared by tripping the faulted line in a normal 9 cycle clearing time.

4.1.4 Fault Location 4

Faults (post-Project, and both 3-phase and single-line-to-ground) were selected to be applied to the new MTSDAVEJ 500 kV bus that was added by the Project at Billings. The model used for this simulation is Line 2 with power scheduled to Denver that had heavy power flows through the region of the fault (WECC Heavy Summer model).

After the duration of the fault, the new 500 kV transmission line from MTSDAVJ to MTSDAN 500 kV was dropped to clear the fault. The three-phase fault was cleared by tripping the faulted line in a normal 3 cycle clearing time. The single-line-to-ground fault was cleared by tripping the faulted line in a normal 9 cycle clearing time.

4.1.5 Fault Location 5

Faults (post-Project, and both 3-phase and single-line-to-ground) were selected to be applied to the new MTSBLGS1 500 kV bus that was added by the Project at Billings. The model used for this simulation is Line 3 with power scheduled to Salt Lake City that had heavy power flows through the region of the fault (WECC Heavy Summer model). Manual simulation of the Colstrip ATR was executed for the post-Project 3-phase and single-line-to-ground faults.

After the duration of the fault, the new 500 kV transmission line from MTSBLGS1 to MTSDILL 500 kV was dropped to clear the fault. The three-phase fault was cleared by tripping the faulted line in a normal 3 cycle clearing time. The single-line-to-ground fault was cleared by tripping the faulted line in a normal 9 cycle clearing time.

4.1.6 Fault Location 6

Faults (pre- and post-Project, both 3-phase and single-line-to-ground) were selected to be applied to the existing SHELBY 230 kV bus. The model used for this simulation is Line 1 with power scheduled to Lethbridge that had heavy power flows through the region of the fault (WECC Heavy Summer model). The pre-Project scenarios were run on the corresponding base case model.

After the duration of the fault, the existing 230 kV transmission line from CNRDWAPA to SHELBY 230 kV was dropped to clear the fault. The three-phase fault was cleared by tripping the faulted line in a normal 5 cycle clearing time. The single-line-to-ground fault was cleared by tripping the faulted line in a normal 25 cycle clearing time.

4.2 Dynamic Stability Study Results

4.2.1 Fault Location 1

Three-phase and single-line-to-ground faults at Location 1 did not cause any transient violations of stability criteria. The system proved to be transiently stable for these scenarios. No transient voltage violations or frequency dips exceeding criteria were observed during these faults. Post-Project voltage levels were near pre-contingency levels. This fault scenario meets all key stability criteria.

4.2.2 Fault Location 2

The system proved to be transiently stable for these scenarios. No transient voltage violations were observed for any of the scenarios. There were a number of pre-Project frequency dips that occurred in the Montana and WAPA U.M. area that were fixed by the Project. For the post-Project three-phase fault there were two frequency dips that occurred in the Montana area. The worst dip was 59.56 Hz for 6.8 cycles at BILGEN I 13 kV. For the post-Project single-line-to-ground fault there were three frequency dips. The worst dip was 59.56 Hz for 9 cycles at the new project generator 24 kV bus. This fault scenario meets all key stability criteria; however, the above mentioned momentary frequency fluctuations should be noted.

4.2.3 Fault Location 3

Fault scenarios at Location 3 were conducted on Project buses and lines, and are therefore not compared to any pre-Project case. The system proved to be transiently stable for these scenarios. Analysis of the results for faults at this location show that no voltage violations were created for three-phase or single-line-to-ground faults. There were no frequency dips exceeding criteria for the single-line-to-ground fault, and no three-phase fault frequency dips exceeding load bus criteria. For the three-phase fault one frequency violation occurred at the new project generator 24 kV bus, reaching 59.58 Hz for 6.8 cycles. Post-Project voltage levels were near the pre-contingency voltage levels.

4.2.4 Fault Location 4

Fault scenarios at Location 4 were conducted on Project buses and lines, and are therefore not compared to any pre-Project case. Analysis of the results for faults at this location show that no transient stability violations were created for the three-phase or single-line-to-ground faults. This fault scenario meets all key stability criteria.

4.2.5 Fault Location 5

Fault scenarios at Location 5 were conducted on Project buses and lines, and are therefore not compared to any pre-Project case. Analysis of the results for faults at this location show that no voltage or frequency violations were created for three-phase or single-line-to-ground faults. This fault scenario meets all key stability criteria.

4.2.6 Fault Location 6

Three-phase and single-line-to-ground faults at Shelby 230 kV caused minimal disturbances in both the pre- and post-Project cases. No transient voltage or frequency criteria were violated for the three-phase fault scenarios. This fault scenario meets all key stability criteria.

5. COST ANALYSIS

Transmission and substation estimated costs for the individual studies are as shown in Table 4. The generation substations do not include any distribution equipment. The estimated costs begin at the low side bushings of the Generator transformer and continue through to the transmission tie-in buses.

Table 4 - Transmission and Substation Cost - Project 3

Line Code	Substation Cost (thousands)	Transmission Costs (thousands)	Total Costs (thousands)
L1	$86,905	$327,214	$414,119
L2	$59,869	$283,018	$342,887
L3	$72,009	$319,131	$391,140

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 that 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 5 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 5 - Viability Summary

Project	Line Code: Description	Schedule	Comments	Viable Project?
Project 3 500 MW Coal-fired near Billings	**L1: 500 kV to Spokane; 230 kV Shelby to Lethbridge**	Spokane	One slight overvoltage. Correct by adjusting transformer tap.	**Yes**
		Salt Lake City	Line 1 is not adequate for this schedule.	No
		Lethbridge	Dependence on existing B.C.-Alberta transfer. Too many changes to Alberta system.	No
	L2: 500 kV to Denver	Denver	Meets Criteria.	**Yes**
		Salt Lake City	Overload: Bonanza-Mona 345 kV (known constraint)	No
	L3: 500 kV to Salt Lake City	Salt Lake City	One slight overvoltage. Correct by adjusting transformer tap.	**Yes**

The table above illustrates that each of the three transmission line alternatives studied in this Project are viable when the Project generation is scheduled to the corresponding market. Schedules that were deemed non-viable created overloads and contingency violations that may not be easily mitigated.

7. CONCLUSIONS

It has been shown through the completion of this study that a 500 MW thermal generation facility installed near Billings, Montana could have a desirable impact on the power system if implemented in conjunction with certain transmission line alternatives and power flow schedules. The results also indicate that some power schedules are not as feasible with the given transmission line alternatives as other power schedules.

For the Line 1 transmission line alternative, it was shown that the new generation scheduled to Spokane introduced the least amount of new violations, and power scheduled to the Salt Lake City area introduced the most new violations. Line 1 is viable when generation is scheduled to Spokane, but not viable to reach the Salt Lake City market.

For the Line 2 transmission line alternative, it was shown that power scheduled to Denver introduced the least amount of new violations and is a viable option for that market. When the new generation was scheduled to the Salt Lake City area, significant new violations occurred, making this a non-viable option for that market.

For the Line 3 alternative, it was shown that power scheduled to Salt Lake City fixed or improved more violations than it caused. Line 3 is a viable transmission alternative for the Salt Lake City market.