British Columbia Transmission CORPORATION™

System Impact Study of

Network Integrated Transmission Service (NITS) Update

Mica and Revelstoke Peaking Units

Contingency Resource Plan 2

Version 0

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System Planning and Performance Assessment

British Columbia Transmission Corporation

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Executive Summary

Following the British Columbia Utilities Commission approval of BC Hydro's Contingency Resource Plans (CRP) from the 2006 IEP, BC Hydro submitted two CRPs to BCTC on December 18 2007 as a generation resource data update for the Network Integrated Transmission Service (NITS). In CRP2, after the addition of Revelstoke Unit 5 in 2010, the peaking units Mica Unit 5, Mica Unit 6 and Revelstoke Unit 6 are scheduled in 2013, 2014 and 2018 respectively. Thereafter, BCTC was requested to perform System Impact Study (SIS) to identify the resulting transmission requirements and schedule the transmission reinforcement projects to accommodate the system interconnections of these peaking units.

The major generation dispatching pattern that BC Hydro specified in this SIS is dispatching all generation resources in the South Interior to their maximum continuous ratings. Based on the comprehensive transmission system studies, the following transmission system reinforcements have been recommended to accommodate the peaking unit system interconnections:

Mica Unit 5 integration in 2013:

(1) 50% series compensation on 5L71 and 5L72 with 2960 Amps of nominal rating.

Even thought 40% series compensation on 5L71 and 5L72 has been identified to be the minimum transmission requirement to accommodate the integration of Mica Unit 5, due to only one year time difference of In-Service-Date (ISD) from the Mica Unit 6 in CRP2, 50% series compensation is proposed at this stage to accommodate both Unit 5 and Unit 6 in Mica plant.

If this project definition phase is approved in the Commission's Decision on BCTC's F2010/F2011Transmission System Capital Plan around May 2009 and BCTC commences the project definition phase immediately, the project lead time may not be adequate for project CPCN application, engineering and construction.

Mica Unit 6 integration in 2014:

With Mica Unit 5 system upgrades in place, the transmission requirements for Mica Unit 6 interconnection include:

(2) Install one 500 kV 250 MVAR Mechanically Switched Capacitor (MSC) bank at Nicola substation. The size of the MSC bank will be optimized in project definition phase.

(3) Load shedding RAS scheme for double contingency of 5L71 and 5L72.

Revelstoke Unit 6 integration in 2018:

The Revelstoke Unit 5 integration is assumed to have been done by adding only one 250 MVAR MSC at Ashton creek substation. Because the 1-hour summer circuit ratings can be used to address the post-contingency transfer requirement at the Revelstoke cut-plane and the West of Ashton Creek/Vaseux Lake cut-plane, no thermal upgrades would have been done on 5L77 and 5L76 for the Revelstoke Unit 5 stage. On the base of South Interior system configuration by 2014 and without the consideration of Waneta Expansion (WAX), the transmission requirements for Revelstoke Unit 6 includes:

(4) 50% series compensation on 5L91 and 5L98 with 2730 amps of nominal rating.

(5) An additional 250 MVAR MSC bank at Nicola substation.

(6) RAS load shedding scheme for double contingency of 5L75 and 5L77.

The series compensation on 5L91 and 5L98 project, named as SISC, was proposed in F2009 Transmission System Capital Plan for Waneta Expansion integration and presently this SISC project is under definition phase. If the Waneta Expansion becomes nominated as a BC Hydro's network resource in the near future, in service before Revelstoke Unit 6, the alternative transmission reinforcements of the SISC project to accommodate the interconnection of Revelstoke Unit 6 are:

(7) 50% series compensation on 5L76 and 5L79 with 3040 amps of nominal rating.

(8) 50% series compensation on 5L96 with 2730 amps of nominal rating.

In the recommended transmission reinforcements for the peaking units in Mica and Revelstoke plants, a simultaneous outage of 5L75 and 5L77 (the two REV-ACK) would result in the loss of the entire 3000 MW Revelstoke plant; a simultaneous outage of 5L71 and 5L72 would result in the loss of the entire 2880 MW Mica plant. Under some system conditions, the sudden loss of 3000 MW of generation in BC would result in unacceptable voltage and frequency deviations in the BC and US systems unless some load is immediately shed in BC. Therefore load-shedding RAS were proposed to address these rare but severe double contingency events for the considerations of cost-effectiveness, acceptability and the overall impact on the reliability of supply to BC Hydro's customers. The load shedding RAS logic design is out of the study scope and will be fully addressed in operational planning study. However, building the Downie substation and associated 500 kV transmission lines to Mica and Revestoke is able to avoid the application of load shedding RAS under double contingencies, but the capital costs are extremely high. For the further interest in the system reinforcement options associated to Downie substation, please refer to Section 7 in detail.

In this report, winter continuous ratings (0°C) and summer continuous ratings (30°C) of 500 kV transmission lines are used to assess the system thermal limits; and some thermal constraints on the lines and line terminals are identified under some first contingency conditions. Two generic options to alleviate the transmission line thermal constraints in summer are:

1) *Transmission line thermal upgrades on 5L71, 5L72, 5L75, 5L77 and 5L76 in summer ratings. Further engineering investigation will be performed later in Facility Study stage; or*

2) *Application of dynamic thermal rating. The transmission line thermal ratings will vary with the ambient temperature. Generation run-back schemes may be applied after permanent first contingencies if the ambient temperature is high.*

According to BCTC's "Open Access Transmission Tariff", a System Impact Study focuses on the system option study and technical comparison; project cost estimates are not necessary at this stage. Engineering service provider(s) will be involved in *station planning, protection & control and telecommunication in the Facility Study stage for project preliminary engineering and cost estimation.*

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1 INTRODUCTION

To respond BC Hydro's OASIS Transmission Request #71699426 dated November 26 2007, BCTC conducted this system impact study to identify the transmission system constraints and transmission system requirements for the transmission service revised for the network resource update in BC Hydro's Contingency Resource Plans. This study is a continuation of the Preliminary Integration Study for Revelstoke and Mica Peaking Units that BCTC performed for BC Hydro's generation sequence optimization in 2007. In addition to the preliminary study, multiple system reinforcement options are considered.

In BC Hydro's NITS Data – BCUC-Approved CRPs and Other Updates, the major generation resource update after October 2010 in South Interior includes Mica Unit 5, Mica Unit 6 and Revelstoke Unit 6. In an agreement with BC Hydro, the Contingency Resource Plan (CRP) 2 is the critical resource plan for this System Impact Study for peaking units in SI, in which Mica Unit 5, Mica Unit 6 and Revelstoke Unit 6 are scheduled in October 2013, October 2014 and October 2018 respectively.

This system impact study focuses on the interconnection of the Mica and Revelstoke peaking generation units into the SI transmission system and identifies the transmission system reinforcements for each plant. The associated detailed station, protection and telecommunication work, transmission line thermal upgrades and cost estimate are not included. These will be fully addressed in the Facility Study stage.

In order to meet the load growth in Lower Mainland and Vancouver Island and improve BC electric system reliability, the ILM system reinforcement project, a second 500 kV line between Nicola (NIC) and Meridian (MDN) substations, has been scheduled to be completed by October 2014. This reinforcement will increase the ILM transfer capability significantly. The transfer demand and transfer capability at the West of Nicola cut-plane is addressed in this study but the transmission requirement identification and system reinforcement recommendation at ILM system are out of this study scope.

2 SOUTH INTERIOR TRANSMISSION SYSTEMS

South Interior is one of the largest generation bases in British Columbia. The total installed generation capacity interconnected to BCTC/BC Hydro's system in the South Interior is about 5264 MW based on the generator's nameplate ratings, including Revelstoke, Mica, Kootenay Canal, Seven Mile and Arrow Lakes Hydro.

In the West Kootenay area, several hydro power plants, such as Waneta, Brilliant, South Slocan, Lower Bonnington and Corra Linn are interconnected into Fortis BC (FBC) transmission system, the total maximum observed continuous generation output in FBC system is about 813 MW. BCTC also provides power wheeling service to Fortis BC to deliver the area generation surplus to the Okanagan under the General Wheeling Agreement (GWA).

SI bulk transmission system consists of 500 kV transmission lines interconnecting Mica plant, Revelstoke plant, Nicola substation, Ashton Creek substation, Vaseux Lake substation, Selkirk substation and Cranebrook substation. It connects to the Alberta Electric System via 5L94 and BPA system via 230 kV line 2L112.

To better explain the transmission demands and transfer capabilities of South Interior transmission system, BCTC defined five major cut-planes as shown in Figure 2.1.

1) The "West of Selkirk" cut-plane consists of 500 kV 5L91 and 5L96 transmission lines and a 161 kV line from ASM to GFT substations owned by Fortis BC. Generation surplus from Selkirk area and power import from Alberta flow west through this cut-plane towards Nicola substation.

2) The second cut-plane is the "West of Ashton Creek/Vaseux Lake" and consists of lines 5L76, 5L79 and 5L98. Power arriving at Ashton Creek substation from Revelstoke and power from Selkirk Substation flow through this cut-plane towards Nicola substation. This cut-plane measures the power injection into the Nicola substation from Selkirk and Ashton Creek areas.

3) Revelstoke cut-plane, which consists of 500 kV transmission lines outgoing from Revelstoke plant, 5L75 and 5L77, measures the generation output of Revelstoke generation units.

4) Mica cut-plane consisting of 5L71 and 5L72 measures the generation output from Mica units.

5) The last cut-plane in SI is “West of Nicola” and measures the total power injection from Columbia resource base to ILM system.

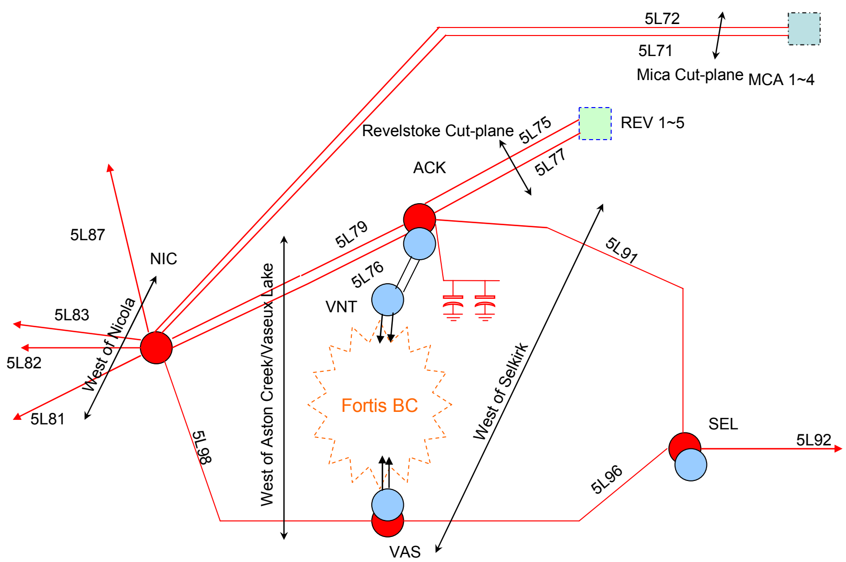

Figure 2.1 Cut-plane Definition in South Interior Transmission System

3 ASSUMPTIONS AND CRITERIA

3.1 The Study Year of Interest

Two study years are selected, F2015 and F2019, because the Mica Unit 5 and Mica Unit 6 will be in service in 2013 and 2014 respectively, and the Revelstoke Unit 6 is scheduled to enter service in October 2018 in BC Hydro’s CRP2.

3.2 Load Information

The system (domestic) peak load is based on BC Hydro's 2006 December load forecast for the total integrated system peak load (with DSM) This is the load forecast associated with the BCUC approved Contingency Resource Plans.

- The BC Hydro's high load forecast (P90) is used in this study which is consistent to the CRP2.
- 100% of the EE1 and EE2 and 80% of the EE3/4/5 are taken into account during system peak load condition.
- The heavy summer load level and light summer load level are specified in the study cases based on BCTC's engineering judgment. These lower load levels are applied in this study for sensitivity analysis.
- The power loads in Fortis BC system are modeled separately.

3.3 Resource Plan and Generation Dispatching Pattern

- Per BC Hydro's request in NITS Update 2007, the generation resources in Coastal region (Lower Mainland and Vancouver Island) should be dispatched to their Dependable Generation Capacities (DGC) to serve local load under heavy load conditions.
- BC Hydro's CRP2 received on January 04 2007 is used as the basic resource plan for the studies.
- The generation resources in Fortis BC system are treated as system generation resource because BCTC/BC Hydro has the authority of dispatching these resources through the inter-utility agreements with Fortis BC and Columbia Power Corporation (CPC). These resources are nominated too in BC Hydro's NITS 2007 Update data package.

- Waneta Expansion (WAX 435 MW) is **NOT** included because it is not nominated as BC Hydro's network resource in CRP2. The associated transmission reinforcements identified by BCTC previously is not considered accordingly.

- Per BC Hydro's request, all the major generation plants in South Interior East and Fortis BC systems are dispatched to their maximum continuous ratings (MCR). The transmission system planned under this generation pattern will provide adequate flexibility for generation dispatch.

- Low-voltage/voltage-stability dominates the transfer limits at the Mica, Revelstoke and West of Ashton Creek/Vaseux Lake cut-planes, the generation reactive power capabilities at Mica and Revelstoke are significant and the reactive power capabilities at maximum real power output are listed in Table 2.1. The VAR capability of each existing unit is based on the recent generation testing records.

Table 2.1 Reactive Power Capability at Revelstoke and Mica Plants

Revelstoke		Mica	
Unit	VAR Capability (MVAR)	Unit	VAR Capability (MVAR)
G1	164.3	G1	107.0
G2	153.8	G2	107.0
G3	139.9	G3	118.0
G4	154.9	G4	118.0
G5	154.9	G5	154.9
G6	154.9	G6	154.9

3.4 Interchange

- Generally the BCTC – BPA interchange is set at 230 MW export to United States, which presents the firm transfer obligation to Seattle City of Light.

  However, 1400 MW import is also considered in some study cases in order to stress the transmission system from Selkirk to Nicola especially during the heavy load conditions, which presents the BC Hydro's potential request of dispatching Canadian Entitlement (CE) back to the province for resource adequacy consideration in some years. Full return of CE is considered in this study for sensitivity analysis.

- The interchange between Alberta and BC is set at 0 MW. According to the Point-to-Point service contract, the firm transfer service from Alberta to BC should be scheduled with same amount of generation reduction in the Selkirk area.

3.5 Transmission System Configurations

- Transmission reinforcements in the South Interior proposed for execution phase in BCTC's F2009 Capital Plan have been included in the study base cases. These reinforcements are Selkirk T4, one -122.5 Mvar mechanically-switched shunt reactor at Selkirk substation, and two 250 Mvar mechanically-switched shunt capacitor banks (MSCs) at Ashton Creek substation.

- The second 500 kV transmission line from Nicola substation to Meridian substation, 5L83, will be in service by 2014. This project will provide adequate transfer capability at Interior to Lower Mainland (ILM) grid to address the new generation resource additions in South Interior.

- The 230kV VAS - LEE system upgrade project is completed by 2010 as specified in the Fortis BC 2006-Jul-26 Capital Plan Application[1]. This project provides a normally closed 230 kV path between Vaseux Lake substation and Ashton Creek substation through the entire Fortis BC system in Okanagan area.

3.6 Transmission Planning Criteria and Assumptions

NERC/WECC Planning Standards and BCTC Planning Standards are referred in this study. Several specific rules are summarized as follows:

[1] The FortisBC Capital Plan Application to the BCUC is available at: http://www.fortisbc.com/about_us/regulation/capital_expenditure/capital_exp_2007.html

- The transmission system should have adequate transfer capability to deliver the maximum continuous generation output from Mica or Revelstoke plant to main system during normal system conditions and after single transmission outages during winter peak load periods.

- The new Revelstoke and Mica units should not reduce the transfer capabilities at the West of Selkirk cut-plane during the heavy load period under any single-contingency condition.

- No post-contingency automatic or manual actions (such as load shedding or generation shedding) are applied after the first single system contingency during the heavy load period. However, BCTC may accept some exceptions if the amount of shedding is less than the largest unit on the transmission system and the required investment to avoid the generation shedding cannot be justified.

- Continuous winter/summer ratings of the transmission lines are used to assess the thermal capability of the transmission lines. Application of overload rating during system contingencies, especially in summer, is considered as an option to defer transmission line thermal upgrades.

- Generation restrictions are allowable during the planned breaker outages or line maintenances. For example, during one breaker outage of 5L71 for maintenance in Mica, the 5L72 contingency may result in overload on the remaining 5L71 line breaker. Generation restriction is required to prevent such a breaker overload phenomenon in real-time operation or to protect the system from the next single contingencies.

4 METHODOLOGIES

4.1 Contingency Analysis

- Power flow based contingency analysis is performed to investigate transmission system loading capability and voltage profile after the first single contingencies.
- In contingency analysis, all the voltage adjustment functions such as transformer tap-changing and shunt switching are blocked; the corresponding voltage deviation should be less than 10% (5% is preferable) at bulk transmission systems.
- After a permanent transmission outage (N-1), system adjustment actions are adopted to recover the system voltage profile. The bus voltage at major bulk system substations should not lower than 0.95 pu after proper system adjustments.

4.2 Voltage Stability Study

- A PV-Curve-based voltage stability analysis tool is used to calculate the system transfer limit dominated by voltage stability.
- To calculate the transfer limit, a 5% power margin is applied to the maximum post-contingency operating point (or the collapse point) under first single contingencies.
- The generation levels at (a) Revelstoke, (b) Mica and (c) in the Selkirk area are scaled up individually to determine the transfer limits of (a) the Revelstoke to Nicola system, (b) the Mica to Nicola system and (c) the West of Selkirk cut-plane respectively. During these transfer limit studies, the generation level in the Lower Mainland and Vancouver Island is adjusted to increase the transfers at South Interior and ILM systems.

4.3 Dynamic Simulation

- Transient stability studies have been performed using PSS/E program.
- A three-phase fault was applied at either end of the transmission lines related to Revelstoke and Mica (5L75, 5L77, 5L71, 5L72, 5L76 and 5L79).
- A 4-cycle fault clearance time is applied to isolate the faulted transmission equipment with unsuccessful three-phase reclosing for permanent faults.
- The relative rotor angles of the major generators in South Interior are monitored and used as the key parameter to judge the system stability. Also the transient voltage variation is monitored and used as a second parameter of the system capability to tolerate system disturbances and confirm that voltage dip criteria were met.

5 TRANSMISSION SYSTEM ASSESSMENT PRIOR TO NEW PEAKING UNIT ADDITIONS AT REVELSTOKE AND MICA

In BCTC's F2009 Transmission System Capital Plan, several transmission projects have been proposed in the South Interior prior to the new generation additions of Mica Unit 5, Mica Unit 6 and Revelstoke Unit 6, including the addition of a fourth 500/230 kV transformer (SEL T4) at Selkirk, the installation of a 500 kV, 122.5 MVAR shunt reactor at Selkirk substation, and the addition of two 250 MVAR MSC banks at Ashton Creek substation. The SI transmission system configuration prior to new peaking unit additions is shown in Figure 4.1.

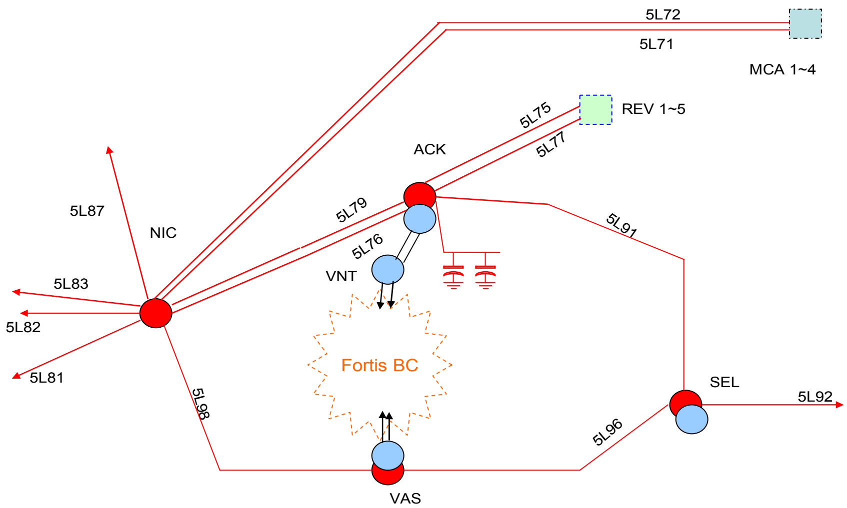

Figure 4.1 South Interior Transmission System Configuration (2014)

5.1 Demand Analysis

In BC Hydro's 2006 IEP, Revelstoke G5 is scheduled to be in service by 2010 and several new small hydro IPPs will be installed in SI by 2014. The transfer demands at the defined cut-planes in South Interior are generally dominated by area generation surplus and are summarized in Table 5.1 for different system load levels with MCR for all generation units in South Interior.

In addition, the Canadian Entitlement (CE) is nominated as network resource in BC Hydro NITS2007 update data. BCTC understands that the CE is not to be used as a long term planning resource however, the partial return of CE may be required for generation resource adequacy in the short term. In this study, for the purpose of demand analysis, one more scenario with full return of CE during the winter peak load condition is considered; and the associated transmission demands at the cut-planes are summarized in Table 5.1 too. This scenario could be used for the sensitivity analysis for transfer capability assessment.

Table 5.1 Pre-contingency Transfer Demands (CU) (MW)

Cut-Plane	Heavy Winter Load	Heavy Summer Load	Light Summer load	Heavy Winter Load with CE 1400 MW	Notes
Revelstoke	2529	2539	2539	2529	
Mica	1871	1871	1871	1871	
West of Selkirk	2127	2254	2566	2422	
West of Ashton Creek/Vaseux Lake	3647	3975	3672[1]	3910	1
West of Nicola	5255	5472	3524[1]	5147[2]	1

Notes:
1. At light load condition, e.g. light summer load, Revelstoke and Mica may operate at lower outputs because the domestic system load is low.
2. When considering full Return of CE, generation output at Mica plant is reduced to avoid the reverse of power flow to North Interior.

Based on Table 5.1, some observations or explanations are summarized as follows:

1) The transfer demands at the Revelstoke cut-plane is determined by the generation output in Revelstoke Plant. All the units in Revelstoke could be required to operate at their maximum output levels to serve domestic peaking load. During spring freshet season, Revelstoke may need to operate at the maximum output level (the probability is low).

2) The generation output level at the Mica station determines the transfer demand at the Mica cut-plane. Mica plant usually operates as a system peaking resource and frequency controller in BCTC/BCH system. During spring freshet season, Mica plant usually operates at it minimum output level because Kinbasket reservoir has large storage.

3) The transfer demand at the West of Selkirk cut-plane is determined by generation surplus in Selkirk area (including Fortis BC system). Due to the limitation of storage capacity, the generation units in Selkirk area may operate

at their maximum continuous ratings simultaneously[2] to avoid the potential water spills even though sometimes the domestic system load is low. Therefore, the transmission demand at the West of Selkirk cut-plane reaches the peak generally under light load condition during freshet season.

4) The transfer demand at West of ACK/VAS is dominated by both generation output at Revelstoke and generation surplus at Selkirk area. During the freshet season, when all the generation units at Selkirk area are dispatched to their maximum continuous ratings to avoid potential water spills, some Revelstoke units are off-line at light load conditions. The transmission demand at this cut-plane could be more critical at heavy load condition in winter.

5) West of Nicola cut-plane is dominated by generation dispatching patterns in SI and also affected by the total system load level. i) At heavy winter load condition, SI generations are dispatched to their maximum continuous ratings while the coastal generation has been dispatched to the dependable capacity. ii) At heavy summer load condition, SI generation can be dispatched to their maximum capacity but coastal generation has to be cut-off. iii) During freshet time with light system load, even though dispatching the coastal generation and Northern Interior generation to the minimum level, some of the generation units at Revelstoke and Mica should still be off to balance the domestic load. Consequently, heavy load condition could be more critical practically at this cut-plane.

5.2 Transfer Capabilities

The transfer capability is defined as the maximum power transfer through a transmission cut-plane that can be reliably and securely served under the defined system operating conditions including system normal and after first system contingency, which may be limited by thermal rating, voltage violation, voltage stability and/or transient stability. In SI transmission system, system voltage is the first concern to limit the transmission capability.

[2] In this benchmark, the coincident factor of all SI resources operating at their MCR is assumed to be “1”.

Transfer Capability at the Revelstoke Cut-plane:

After installing two 500kV shunt capacitor banks at Ashton Creek substation, the thermal constraint is becoming the transfer limit at the Revelstoke cut-plane in summer. The continuous thermal ampacities (at 30 °C ambient temperature) of 5L75 and 5L77 are 2870 Amps and 2265 Amps respectively. Therefore the firm thermal limit at the Revelstoke cut-plane is about 1920 MW; it is not adequate for the full power output of the existing four units or the five units by 2010.

However, the overload ampacities of 5L75 and 5L77 in summer are 3370 Amps, which are adequate to fully transfer the maximum generation power out of Revelstoke Plant in a short time (1 hour). Generation re-dispatch may be required if the outage can not be restored quickly. In addition, a dynamic thermal rating scheme is suggested in future real-time operation to update the line thermal rating dynamically with the variation of the ambient temperature. Otherwise, thermal upgrade project on 5L75 and 5L77 is required.

Transfer Capability at the Mica Cut-plane:

The transfer capability at the Mica cut-plane is about 1650 MW limited by voltage stability for single line contingency. It is not adequate to firmly deliver the 1876 MW (MCR) of generation out and a generation shedding scheme is presently applied in real-time operations.

Transfer Capability at the West of Selkirk Cut-plane:

The West of Selkirk cut-plane includes the transmission paths to deliver the generation surplus at South Interior East (SIE) area toward Nicola.

The transfer demands at the West of Selkirk Cut-Plane vary within a broad range for different system load levels in different seasons. In winter, the SIE area generation surplus is needed to serve the provincial system peak load. Therefore, in winter, the West of Selkirk Cut-Plane needs to have adequate transfer capability to deliver the regional generation surplus both before and after a single-contingency event. However, the area generation surplus reaches a peak under light load conditions during the freshet season.

In addition, the Eastern Inter-tie, consisting of 2L112 from Nelway to Boundary, has a significant impact on the transfer capability assessment at West of Selkirk Cut-Plane. The Eastern Inter-tie provides temporary support after a transmission outage and is able to take some power down to BPA system temporarily without any system adjustment function.

The power flow / contingency analysis results based on the pre-contingency demands listed in Table 5.1 are summarized in Table 5.2.

Table 5.2 Power Transfer and Transfer Limits at the West of Selkirk Cut-plane (MW)

Conditions		Type	Heavy Winter Load	Heavy Summer Load	Light Summer Load	Heavy Winter Load with CE Return	Notes
Pre-contingency	System Normal	Transfer Demand	2127	2254	2566	2422	Note 1
Post-Contingency	5L96 Contingency	Transfer	1793	1900	2169	case un-solved	
		Transfer Limit	2050	2155	2255	n/a	Note 2
	5L91 Contingency	Transfer	1900	2006	2214	2127	
		Transfer Limit	2020	2113	2239	2137	Note 2

Notes:
1, the pre-contingency power transfers under system normal are identical to the transfer demands at the cut-plane shown in Table 5.1.
2, the transfer limit is the lower one of voltage stability limits and the transfer capability dominated by post-contingency bus voltage limits (≥0.95 pu at 230kV and above) with proper voltage regulation actions including transformer tap-changing and shunt switching.

The observations to Table 5.2 are:

1) Without any system adjustment actions, due to the system configuration change after single transmission contingency at the West of Selkirk cut-plane, the Eastern Inter-tie (2L112) will take an additional amount of power down to the BPA system and temporarily reduce the post-contingency transfer through the cut-plane. However, if the transmission outage cannot

be restored in a short time, the system adjustment action on Nelway phase shifting transformer may be required to restore the transfer at the Eastern Inter-tie to pre-contingency setting; consequently the transfer demand at the West of Selkirk cut-plane will increased close to the pre-contingency transfer.

2) At the system conditions with heavy winter load and without return of CE, the post-contingency transfer limits at West of Selkirk cut-plane are higher than the post-contingency transfer demands but they are slightly lower than the pre-contingency transfer demands. The post-contingency transfer capability shortage is about 50~80 MW. In addition, the historical system operation records indicated that the generation capability in winter at Selkirk area is usually lower than their maximum continuous ratings.

3) At the system conditions with heavy summer load and without return of CE, the post-contingency transfer limits at West of Selkirk cut-plane are higher than the post-contingency transfer demands but they are slightly lower than the pre-contingency transfer demands. The post-contingency transfer capability shortage is about 100~150 MW. A generation re-dispatch is required at this situation.

4) At the system conditions with light summer load and without return of CE, the post-contingency transfer limits are still higher than the post-contingency transfer demands but they are much lower than the pre-contingency transfer demands. The post-transfer capability shortage is around 330 MW. Generation re-dispatch at Selkirk area is required when the transmission outage is permanent in order to restore the power transfer at Eastern Inter-tie to pre-contingency setting. Due to the concerns on larger voltage deviation (>5%), generation shedding scheme may be required in the real-time operation.

5) At the system conditions with heavy winter load and with return of CE, the Selkirk transmission system does not have adequate transfer capability to

deal with the higher transfer demands. Transmission system reinforcement is required in order to fully meet the transfer demands at this scenario. However, when CE is really needed to serve the loads in Lower Mainland and Vancouver Island, generation run-back in Selkirk area could be an economic operating strategy to release the transmission constraint at the West of Selkirk cut-plane.

The South Interior East (SIE) is one of the largest provincial hydro-generation regions. These resources have clear seasonal characteristics: i) In winter, the generation capacity at Selkirk area is usually lower than the maximum continuous rating due to the limits of water inflows and storage capacities. ii) The water inflows are predominantly from snowmelt and these inflows typically increase rapidly during the spring freshet. During this period, it is likely that sufficient generation reserves are available in the rest of the system for serving loads; and slight transmission capability shortfall under N-1 contingency at the West of Selkirk cut-plane should not cause load curtailment. However, these may result in lost energy from potential water spills or limit the opportunities for inter-utility trade.

If firm post-contingency transfer capability is required to fully meet the transmission demands without return of CE and marginally meet the transmission requirement with full return of CE or in freshet season under light load condition, a transmission reinforcement project at the Selkirk substation to Nicola substation system, such as series compensation at 5L91 and 5L98 is required. The transfer limits with this system reinforcement project are summarized in Table 5.3.

Table 5.3 Power Transfer and Transfer Limits at the West of Selkirk Cut-plane (MW) with Series Compensation on 5L91 and 5L98

Conditions		Type	Heavy Winter Load with CE Return	Notes
Pre-contingency	System Normal	Transfer Demand	2422	
Post-Contingency	5L96 Contingency	Transfer	2196	
		Transfer Limit	2280	1
	5L91	Transfer	2177	

	Contingency	Transfer Limit	2340	1

Notes:

1, the transfer limit is the lower one of voltage stability limit and the transfer capability dominated by the lower end of operating voltage rang [0.95 p.u., 1.06 p.u.] at 500/230 kV substations after N-1 contingencies.

Transfer Capability at West of Ashton Creek / Vaseux Lake Cut-plane:

According to the power flow based contingency analysis results and PV-curve based voltage stability study results, no transmission constraint is identified at this cut-plane for system normal and after single transmission contingencies.

Transfer Capability at West of Nicola Cut-plane:

Maximizing the generation output in South Interior will stress the West of Nicola system consisting of 5L87, 5L82, 5L83 and 5L81. A 5L87 outage is becoming the most critical contingency to dominate the transfer capability at the West of Nicola cut-plane. The PV curves with the scenario of dispatching power from SI to Lower Mainland indicate the voltage stability limit at the West of Nicola cut-plane is about 5020 MW, which may not be fully adequate to transfer all SI generation to Lower Mainland when dispatching SI generation units to their maximum continuous ratings. The most possible solution is to install 500kV 250 MVAR shunt capacitor bank(s) at Nicola substation but the project justification for improving transfer capability at the West of Nicola cut-plane (part of ILM system) is out of this study scope.

6 TRANSMISSION SYSTEM REQUIREMENTS OF MICA UNIT 5 AND UNIT 6

In the existing system configuration, the Mica plant directly interconnects to 500 kV backbone transmission system at Nicola substation by two 500 kV transmission lines 5L71 and 5L72. Two new peaking units, Mica Unit 5 and Mica Unit 6, are scheduled in October 2013 and October 2014 respectively in BC Hydro’s CRP2. The new additions of Mica Unit 5 and Unit 6 will mainly increase the power injection at Mica and Nicola substations and may have slight impacts to the rest of SI system subject to different system integration solutions. To integrate the two peaking units in Mica plant, two system integration concepts have been considered: Concept 1 – maintaining the existing system configuration and applying load shedding scheme to address double contingencies; Concept 2 – building new substation(s) and transmission line(s) to avoid isolating Mica or Revelstoke plant under double contingencies. Several system reinforcement options based on these two concepts are discussed in detail in Section 6.

6.1 Do Nothing

Sometimes "Do Nothing" is considered as an option for the generation/load interconnections when transmission capacity is available under system normal condition and remedial action schemes are able to be applied to address any system contingencies. However, it is impossible in this case because the existing system is not able to meet the transfer demand under system normal condition after the additions of Mica Unit 5 and Unit 6.

6.2 Option 1: Series Compensation on 5L71 and 5L72

This option includes series compensation on 5L71 and 5L72 and shunt capacitor bank(s) in Nicola substation.

Transfer Demand Analysis

In this option, about 1000 MW of generation increase at Mica plant will be delivered directly to Nicola substation and further to Lower Mainland load centers. The generation integration will increase the transmission demands at the Mica and the West of Nicola cut-planes. The transfer demands with winter peak load are summarized in Table 6.1 as follows.

Table 6.1 Transfer Demands for Mica Unit 5 and Unit 6 (MW)

Cut-Plane	Heavy Winter Load Before MCA5&6	Heavy Winter Load After MCA5&6
Mica	1871	2829

West of Nicola	5255	6131

Under off-peak load conditions, e.g. heavy summer load and light summer load, it is not required to turn on all the generation units in SI especially in Mica and dispatch them to their MCRs simultaneously. Therefore, the transfer demands listed in Table 6.1 are expected to the maximum transfer demands at the Mica and West of Nicola cut-planes.

System Reinforcement Project Scope

To accommodate the generation integration of Mica Unit 5 and Unit 6, the transmission system reinforcements proposed in Option 1 are depicted in Figure 6.1 and described as follows:

1) Approximately 50% (up to 55%) series compensation on 5L71 and 5L72 transmission lines from Mica to Nicola in 2013. The minimum nominal thermal ampacity is 2960 Amps.

2) One 500 kV 250 MVAR Mechanically Switched Capacitor (MSC) bank at Nicola substation in 2014. The size of the MSC bank will be optimized in Facility Study stage or project definition phase.

3) Thermal upgrades of 5L71 and 5L72 to 3250 Amps of circuit thermal ampacity in summer (30°C). The application of dynamic thermal rating could be the economic alternative to this thermal upgrade.

4) Thermal upgrades of transmission line terminals at 500kV Mica switchgear station and Nicola substation subject to the further engineering investigation in Facility Study stage.

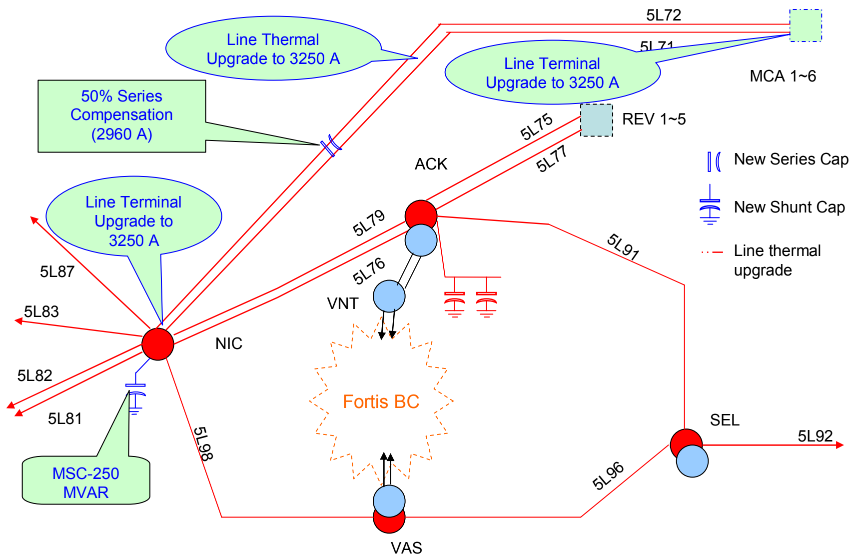

Figure 6.1 Transmission Requirements Option 1 for MCA G6 Integration

Transfer Capabilities

After the implementation of series compensation on 5L71 and 5L72 and the installation of 250 MVAR MSC at Nicola, the transfer capability limited by voltage stability at the Mica cut-plane is increased to about 2810 MW, which is adequate to accommodate the generation integrations of Mica Unit 5 and Unit 6. As well, the transfer capabilities at the West of Nicola will reach 6110 MW (pre-contingency)/ 5860 MW (post-contingency), which are marginally adequate to deliver the SI generation surplus to provincial load centers during the peak load condition.

In summer, either 5L71 or 5L72 out of service may cause a severe overload concern on the remaining line. Thermal upgrades to 5L71 and 5L72 are required to increase the circuit thermal ampacity to 3250 Amps at 30°C ambient temperature to maintain adequate firm thermal capacity at the Mica cut-plane. However, an operation solution is still available – thermal protection scheme (TPS): i) line overload rating is capable to address the short-time overload after single line contingency; ii) if line outage can not be restored quickly, thermal dynamic rating can be used in real-time operation when ambient temperature is taken into account; and iii) if the ambient temperature is high and the dynamic thermal rating is not adequate for a longer time duration, generation restriction will be applied at Mica plant for a permanent transmission line outage.

At Nicola substation, each of 5L71 and 5L72 connects to the 500 kV bus via two 500 kV circuit breakers in parallel (double breakers bus-bar configuration). The breakers have 3000 Amps of nominal rating. When bus-bar configuration is normal before the system contingencies, there is no overload identified after single transmission contingencies. However, if one of the line breakers to 5L71 (or 5L72) is out of service, the other Mica line 5L72 (or 5L71) outage may cause overload on the remaining line breaker of 5L71 (or 5L72). Two solutions to solve this problem are i) replace the line breakers in Nicola substation by 4000 Amps nominal rating, or ii) limit Mica generation output level in real-time operation when line breaker outages to 5L71 and 5L72 are scheduled. The line terminal thermal upgrades at Nicola substation will be addressed in detail in Facility Study regarding the capabilities of circuit breakers, instrument transformers, and line switches.

No transient instability concerns are identified from the dynamic simulation with a series of system disturbances in Category B[3]. The transient stability is not the critical limitation to this system reinforcement option.

System Assessment for Double Contingencies

With the system reinforcements for the integration of Mica Unit 5 and 6, the simultaneously tripping of 5L71 and 5L72 will cause Mica plant to be isolated and result in the loss of about 2829 MW of generation resources in the BCTC system. This will be the most severe double transmission contingency in BCTC system. Under this system condition, the support through the inter-ties from the rest of WECC system is critical. A series of conceptual system analysis have been performed to detect the potential system impacts.

[3] As defined in NERC/WECC Planning Standards, the major system disturbance in Category B means a single phase or three phase permanent fault that may result in the outage of single electric element in the power system, such as generator, transformer or transmission line.

In history, around 11:20 AM on June 06 2002, double contingency of 5L75&77 caused 1500 MW of generation loss in Revelstoke. The peak of import from BPA system to BCTC system reached about 2850 MW temporarily through inter-ties as well as the system survived and was restored in half hour. 2850 MW is the maximum import level on the BPA to BCTC inter-tie in the past ten years.

A steady state benchmark of contingency analysis was performed using the power flow basecases with maximized SI generation under winter peak load condition. At system normal condition, the Eastern Inter-tie was scheduled at zero interchange and Western Inter-tie was scheduled at 230 MW export for firm transmission service to Seattle City Light. No severe overloads and voltage violations are detected in the nearby 500 kV system after 5L71 and 5L72 were removed from service simultaneously.

A dynamic simulation benchmark was performed to investigate the transient system impacts of this double contingency. The observations are:

At post-contingency,

1) No transient overload concerns are detected at the inter-tie lines 5L51, 5L52 and 2L112. However, the dynamic simulation results show a strong momentary power support, around 500 MW, from Alberta system during the disturbance.

2) The dynamic voltage variations at major 500 kV substations are in the acceptable range.

3) The transient frequencies measured at major substations do not decline below 59.5 Hz.

4) Without the momentary supports from Alberta system, for example, AB – BC tie open at pre-contingency, a power swing through the Eastern Inter-tie will cause momentary overload (in cycles) but it recovers to about 370 MW,

which is still lower than the thermal limit of phase shifting transformer (PST) in Nelway substation.

The momentary support capability from neighbor systems varies with system operating conditions, especially the pre-contingency import transfer at BCTC-BPA inter-tie. According to the benchmark results described above, no critical concerns are identified for 5L71&5L72 contingency when 230 MW of power export is scheduled at pre-contingency condition. However, if import power was scheduled at BCTC-BPA inter-tie at pre-contingency condition, simultaneous loss of 5L71 and 5L72 may cause overload at the Eastern Inter-tie and/or cause more critical impacts to BPA system. Therefore, an application of load shedding remedial action scheme will be required to address this double contingency event. The control logics and algorithms will be defined in operational planning stage.

6.3 Option 2: With New Downie Switching Station and New Line to Revelstoke

This is the second option to accommodate the Mica Unit 5 in 2013 and Unit 6 in 2014. In this option, a new 500 kV switching station is proposed at Downie area with looping in 5L71 and 5L72 transmission lines, a third 500 kV transmission line to Revelstoke is considered from Downie substation to avoid the loss of whole Mica plant after double transmission contingency of 5L71/72. In addition, the new transmission line from Downie to Revelstoke will be part of transmission requirements to accommodate Revelstoke Unit 6 integration in 2018.

System Reinforcement Project Scope

The transmission system reinforcements in Option 2 are depicted in Figure 6.2 and described in detail as follows:

1) About 40% series compensation on 5L71 and 5L72 transmission lines from Mica to Nicola in 2013. This is equivalent to about 50% series compensation to the line section of 5L71/72 from Nicola station to future Downie substation. The nominal thermal ampacity is 2730 Amps.

2) Build new 500 kV Downie substation (about 60~70 km away from Mica plant) and loop in 5L71 and 5L72 transmission lines in 2014. In addition, move two existing 500 kV reactors (-122.5 MVAR each) at Mica to Downie substation. Then 5L71 and 5L72 are re-defined as the 500 kV transmission lines from Downie substation to Nicola substation as well as the transmission lines from Mica to Downie substation are named as 5L73 and 5L74 respectively.

3) Build new 500 kV transmission line, 5L78, from Downie substation to Revelstoke plant in 2014. However, the lead time for new line construction is quite long and it is very difficult to make 5L78 into service by October 2014.

4) Thermal upgrades of 5L73 and 5L74 to 3150 Amps of circuit thermal ampacity in summer (30°C).

5) Thermal upgrades of 5L71 and 5L72 to 3000 Amps of circuit thermal ampacity in summer (30°C).

6) Thermal upgrades of transmission line terminals at 500kV Mica switchgear station.

7) Engineering investigations for the thermal upgrades will be performed at Facility Study stage.

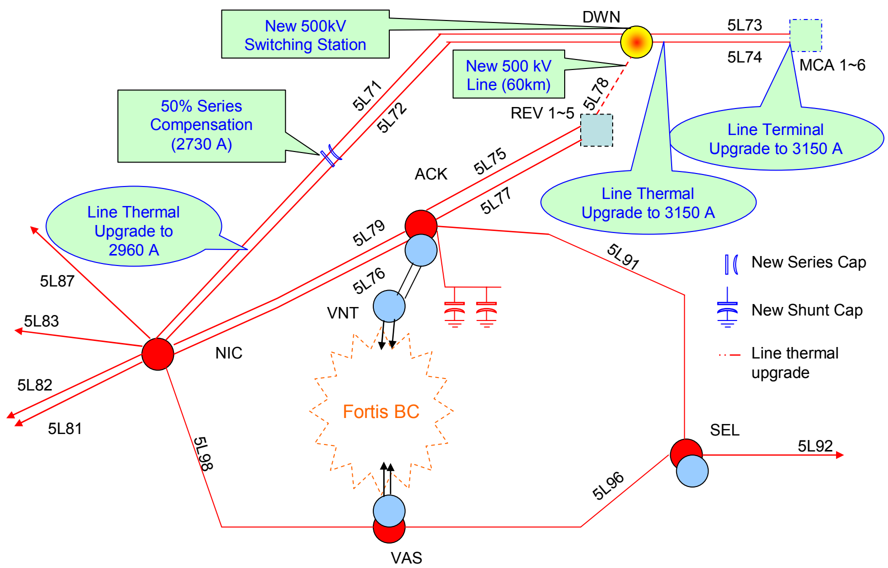

Figure 6.2 Transmission Requirements Option 2 for MCA G5&6 Integration

Transfer Demand Analysis

In this option, with the constructions of new Downie 500 kV substation and new transmission line from Downie to Revelstoke, three transmission cut-planes will reflect the transfer demands with new generation integration at Mica and will measure the system transfer capabilities properly for the proposed reinforcement options. They are the Mica cut-plane, the West of DWN/ACK/VAS cut-plane and the West of Nicola cut-plane. The transfer demands at these cut-planes are summarized in Table 6.2 for heavy winter load conditions.

Table 6.2 Transfer Demands for Mica Unit 5 and Unit 6 (MW)

Cut-Plane	Heavy Winter Load Before MCA5&6	Heavy Winter Load After MCA5&6
Mica	1871	2829
West of Downie, Ashton Creek & Vaseux Lake	---	6468
West of Nicola	5255	6121

Under off-peak load conditions, e.g. heavy summer load and light summer load, it is not required to turn on all the generation units in SI and dispatch them to their MCRs simultaneously. Therefore, the transfer demands listed in Table 6.2 are the expected maximum transfer demands at the Mica, the West of DWN/ACK/VAS and the West of Nicola cut-planes.

Transfer Capabilities

After looping the existing 5L71 and 5L72 into the new 500 kV Downie switching station, the line section from Mica station to Downie substation is about 70 km. The critical limitation at the Mica will be the thermal ratings of 5L73 and 5L74. The thermal upgrade on the transmission lines and line terminals described in system reinforcement scope section will provide adequate transfer capacity at the Mica cut-plane to accommodate the system integration of Mica G5 and G6.

5L71 (or 5L72) (Downie – Nicola) outage is the critical contingency for transmission constraint at the West of DWN/ACK/VAS cut-plane due to voltage stability concerns. The voltage stability limit at this cut-plane is about 6480 MW calculated by PV-curve based methodology. It is adequate to integrate Mica Unit 5 and Unit 6 into the SI system.

With maximizing the SI generation at heavy system load condition, 5L87 is the dominant transmission contingency to limit the transfer capability at the West of Nicola cut-plane. The voltage stability limit is about 5920 MW, which is slightly lower than the pre-contingency transfer demand and it is marginally adequate.

The construction of anew 500 kV Downie switching station and a new 500 kV transmission line 5L78 improve SI system transient stability. In the dynamic simulations at heavy winter load conditions, no transient instability concerns are identified for major 500 kV transmission system disturbances in Category B.

System Assessment for Double Contingencies

When comparing to Option 1, the major advantage of this option is to reduce the possibility of losing a large generation plant entirely (either Mica or Revelstoke) during double contingencies, such as a 5L71&72 outage or a 5L75&77 outage.

In this option, the most severe double contingency is 5L73&5L74 outage, which will result in Mica plant isolation. However, the physical distance from Mica to Downie substation is short, about 70 km. The probability of simultaneous outage of 5L73 and 5L74 should be much lower than losing 5L71/5L72 in the existing system configuration. In addition, it is very difficult to expand Mica switchgear station physically and to locate the transmission right-of-way to Mica. Therefore, considering the cost-effectiveness, in this option, the transmission system would take the risk of losing Mica plant entirely during 5L73 and 5L74 double contingency and a load-shedding RAS will be proposed to address this rare and severe double contingency. Otherwise, a third 500kV transmission line from Mica to Downie is required; the preliminary cost estimate for the new line from Downie to Mica is around $222M.

The new line 5L78 ties Mica plant and Revelstoke plant together at the sending ends. New generation shedding remedial actions (RAS) will be required to address the double contingency of 5L71/72 and double contingency of 5L75/77 (as below). The existing generation shedding RAS to address the double contingency of 5L76/79 should be updated.

1) With losing 5L71 and 5L72 simultaneously, up to three units in Mica should be curtailed to secure the transmission system.

2) With losing 5L75 and 5L77 simultaneously, one unit in Revelstoke will be curtailed to secure the transmission system during heavy transfer condition in South Interior system.

3) These generation shedding remedial action schemes will be defined in system operation studies and designed in the project implementation phase.

7 TRANSMISSION SYSTEM REQUIREMENTS OF REVELSTOKE UNIT 6

In BC Hydro CRP2, the Revelstoke Unit 6 was scheduled to enter service in October 2018. In order to identify the transmission requirements and propose optimal system reinforcement solution, transfer demand analysis and option studies are performed in this section.

7.1 Transfer Demand Analysis

After the interconnections of Mica 5 and Mica 6 by 2014, the addition of Revelstoke Unit 6 in 2018 will increase the transfer demand from Revelstoke to Nicola by another 500 MW. The expected transfer demands at major SI cut-planes are listed in Table 7.1 based on the system configuration of Option 1 in Section 6.

Table 7.1 Transfer Demands for Revelstoke Unit 6 (MW)

Cut-Plane	With Heavy Winter Load after REV G6	With Heavy Summer Load after REV G6	With Heavy Winter Load including DSBR after REV G6
Revelstoke	3027	3038	3027
West of Selkirk	2165	2303	2460
West of ACK/VAS	4107	4483	4387
West of Nicola	6585	4470**	5505*

Notes: * Three units are off at Mica. ** Only one unit is online with minimum output at Mica

7.2 System Reinforcement Options Based on the Option 1 in Section 6

In Section 6.2, as Option 1, 50% series compensation on the 5L71/72 transmission lines and a 250 MVAR shunt capacitor bank at Nicola substation have been proposed to accommodate the system integrations of Mica Unit 5 and Unit 6. The integration of Revelstoke Unit 6 will add another 500 MW transfer from Revelstoke to Ashton Creek system and at the West of Ashton Creek/Vaseux Lake cut-plane as well as it will impact the power flow patterns and transfer capability at the West of Selkirk Cut-plane.

Without additional system reinforcements, the SI transfer capabilities are not adequate to accommodate the integration of Revelstoke Unit 6 due to the voltage instability/insecurity concerns and thermal limitations. Three system reinforcement options are discussed in this section.

7.2.1 Option 1-1: Series compensation on 5L91 and 5L98, and One 250 MVAR MSC at Nicola Substation

In Section 5, the series compensation on 5L91 and 5L98 has been discussed briefly as the potential system reinforcement solution to improve the transfer capability at the Selkirk to west system. BCTC proposed this project definition phase in F2008 Transmission System Capital Plan to accommodate the system integration of Waneta Expansion. Due to the uncertainty of Waneta Expansion, this project definition phase is suspended presently and a project CPCN will be filed when the demand can be justified. This series compensation on 5L91 and 5L98 project is considered as a system reinforcement option to accommodate Revelstoke Unit 6 integration.

To improve the system transfer capability effectively, one 500 kV shunt capacitor bank at Nicola substation is proposed in this option, which will also benefit to the ILM system.

Project Scope:

- 50% series compensation on 5L91 with 2730 amps of nominal ampacity;
- 50% series compensation on 5L98 with 2730 amps of nominal ampacity;
- The second 500 kV 250 MVAR MSC bank at Nicola substation;

- Thermal upgrades at 5L75 and 5L77 to 3360 amps of nominal ampacity in summer (30°C); and
- Thermal upgrades at 5L76 and 5L79 to 2980 amps of nominal ampacity in summer (30°C).

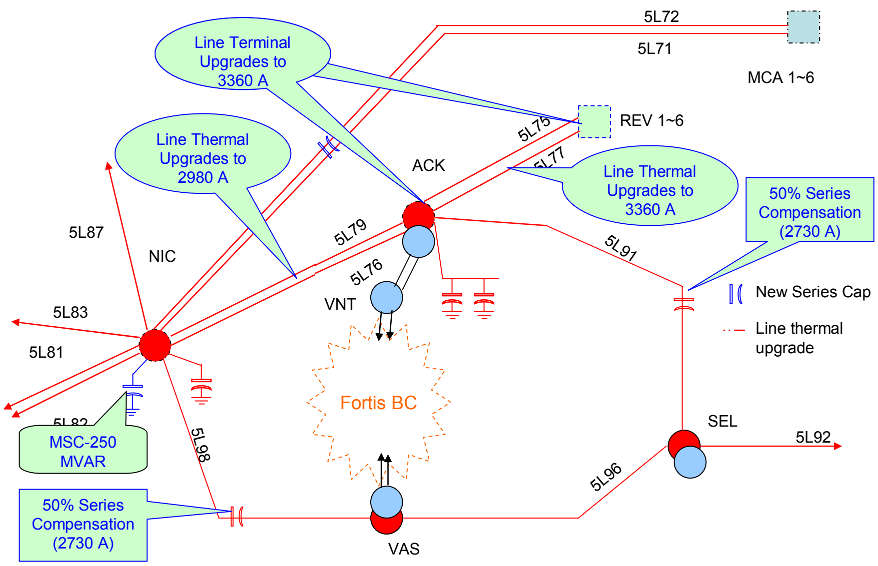

Figure 7.1 Transmission Requirements Option 1-1 for REV G6 Integration

Transfer Capabilities

There is no thermal constraint in winter at the Revelstoke cut-plane, but upgrades of the summer thermal ratings of 5L75 and 5L77 may be required to accommodate the addition of Revelstoke Unit 6. The alternative solution to the thermal constraint in the summer is to apply dynamic ratings to 5L75 and 5L77; as such Revelstoke generation re-dispatch will be required to address the permanent single line outage when the ambient temperature is high.

With the implementation of series compensation on 5L91 and 5L98 as well as the installation of 250 MVAR shunt capacitor bank at Nicola, the transfer capability at the West of Selkirk cut-plane will reach 2300 MW (pre-contingency) / 2100 MW (post-contingency) limited by voltage stability after 5L96 contingency and 2460

MW (pre-contingency) / 2224 MW (post-contingency) limited by voltage drops after 5L91 contingency. This option is able to marginally meet the transfer demands at the West of Selkirk cut-plane under heavy winter load condition when no CE return is considered. In real-time operation, a generation re-dispatch scheme may be required to address permanent N-1 transmission outage. The transfer capability at the West of ACK/VAS cut-plane is about 4307 MW (pre-contingency) / 4125 MW (post-contingency) under winter peak load condition, which is adequate for the transfer demand under winter peak load condition when the return of CE is not included, but is not fully adequate to deliver the generation surplus to Nicola from Ashton Creek and Selkirk areas when considering the return of CE.

In Revelstoke switching station and Ashton Creek substation, each 500 kV transmission line connects to bus-bar configuration through two circuit breakers. Due to the overload concerns during single transmission line contingency, 5L75 or 5L77, generation limitation should be applied to Revelstoke plant during tie-breaker outage at Revelstoke plant or Ashton Creek substation. Otherwise, circuit breaker replacements at Revelstoke plant and Ashton Creek substation will be required.

For the similar consideration to 5L76 and 5L79, generation limitation should be applied to Revelstoke and/or Selkirk generators when the tie-breaker to line 5L76 or 5L79 is out of service for maintenance. Otherwise, circuit breaker replacements are required at Ashton Creek and Nicola substations.

To address the potential overload concerns at line 5L76 (or 5L79) during 5L79 (5L76) contingency in summer, thermal upgrades on 5L76 and 5L79 are required; otherwise, generation re-dispatch scheme will be applied after either 5L76 or 5L79 permanent outage when thermal dynamic ratings are used for 5L76 and 5L79 in summer.

5L87 is the critical transmission contingency to limit the transfer capability at the West of Nicola cut-plane. The transfer capability at the West of Nicola cut-plane is not adequate to deliver the entire generation surplus (6585 MW) in South Interior from Nicola to Lower Mainland in winter. Generation re-dispatch (shedding) scheme is required in the real-time operation unless ILM system is further updated, for example, adding dynamic VAR support at both Nicola substation and Lower Mainland.

No transient instability concerns are identified from the dynamic simulation with a series of system disturbances in Category B. The transient stability is not the critical limitation for this system reinforcement option.

System Assessment for Double Contingencies

With these system reinforcements for the integration of Revelstoke Unit 6, loss of two lines, 5L75 and 5L77, simultaneously from Revelstoke to Ashton Creek will cause Revelstoke plant to become isolated and result in the loss of about 3020 MW of generation resource in BCTC system. This will become the most severe double contingency in BCTC system. Under this system situation, the system support through the inter-ties from the rest of WECC system is very critical.

A steady state benchmark of contingency analysis was performed using the power flow basecases with winter peak load condition and maximizing SI generation. At system normal condition, Eastern Inter-tie is scheduled at zero interchange and Western Inter-tie is scheduled 230 MW export for firm transmission service to Seattle City Light. An overload on Phase Shifting Transformer (PST) at Nelway is identified but the power flow through the PST is still lower than the short-time overload capability. The PST controller will be able to mitigate the overload concerns at the Eastern Inter-tie in minutes. No voltage violations are detected in the related 500 kV system after 5L75 and 5L77 are out of service simultaneously.

A dynamic simulation benchmark was performed to investigate the transient system impacts of this double contingency with the following observations:

At post-contingency,

1) There is a transient overload concern on PST at Nelway but the power flow through PST is still lower than the PST's overload capability.

2) The dynamic simulation results show a strong momentary power support, around 500 MW, from Alberta electric system.

3) The dynamic voltage variations at major 500 kV substations are in the acceptable range.

4) The transient frequencies measured at major substations do not decline below 59.5 Hz

5) Without the momentary supports from Alberta system, for example, AB – BC tie open at pre-contingency, a power swing through the Eastern Inter-tie will cause momentary overload (in cycles) but it recovers to about 600 MW, which is the thermal overload rating of phase shifting transformer in Nelway substation.

The momentary support capability from neighbor systems varies with system operating conditions, especially the pre-contingency import transfer at BCTC-BPA inter-tie. According to the benchmark results described above, the overload on PST at Nelway substation is the major concern that is caused by 5L75&5L77 double contingency when export 230 MW is scheduled at pre-contingency condition. The automatic control scheme to the PST at Nelway will alleviate the overload on PST. However, if import power was scheduled at BCTC-BPA inter-tie at pre-contingency condition, simultaneous loss of 5L75 and 5L77 may cause overload at the Eastern Inter-tie and/or cause more critical impacts to BPA system. Therefore, an application of remedial action scheme may be required to address this most severe double contingency in BC system. The control logic and algorithm should be defined in operation study stage.

7.2.2 Option 1-2: Series compensation on 5L76/79 and 5L96

This is the second option based on the system reinforcements for Mica Unit 5 and Unit 6 in Option1 in Section 6. This option will improve the transfer capabilities at both the West of Selkirk and West of ACK/VAS cut-planes.

Project Scope:

- 50% series compensation on 5L76 and 5L79 with 2730 Amps (at least 2660 Amps) of nominal ampacity;
- 50% series compensation on 5L96 with 2730 amps of nominal ampacity;
- Thermal upgrades at 5L75 and 5L77 to 3380 amps of nominal ampacity in summer (30°C); and
- Thermal upgrades at 5L76 and 5L79 to 2920 amps of nominal ampacity in summer (30°C).

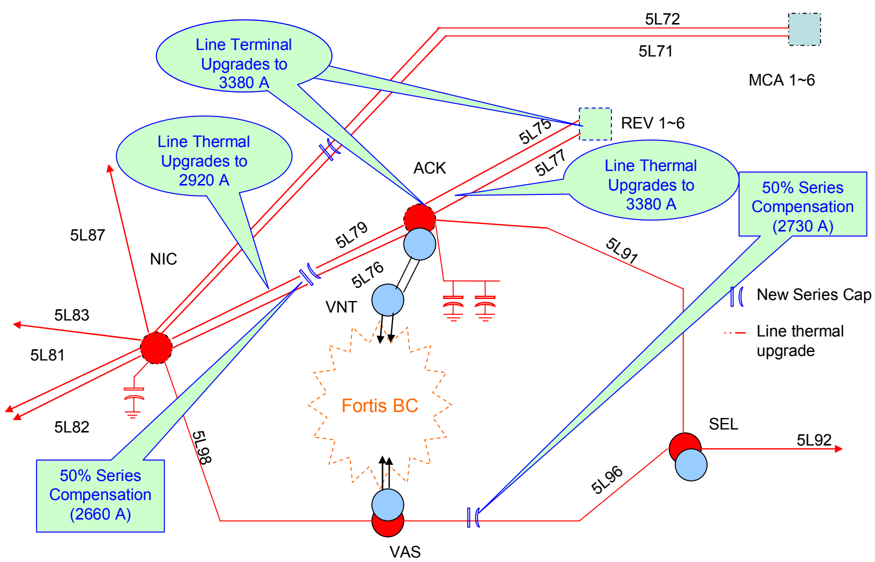

Figure 7.2 Transmission Requirements Option 1-2 for REV G6 Integration

Transfer Capability:

As in Option 1-1, the thermal upgrades at 5L75 and 5L77 will release the thermal constraint at the Revelstoke cut-plane. Otherwise, a dynamic rating should be applied with a generation re-dispatch scheme to address the single transmission line permanent outage in summer.

The PV-curve based voltage stability and other related system study results indicate that:

- The above system upgrades will provide about 2460 MW (pre-contingency) / 2270 MW (post-contingency) transfer capability at the West of Selkirk cut-plane, which is limited by voltage drops after 5L91 contingency and is marginally adequate to the power surplus out-delivery from Selkirk area to West even with the return of CE in winter;

- The voltage stability limit at the West of Ashton Creek/Vaseux will reach 4520 MW (pre-contingency) / 4421 MW (post-contingency) and be adequate to accommodate the new generation integrations in Revelstoke and small IPP's in SI region.

- No system transient instability is identified for the system disturbances defined in Category B.

- The 5L87 will be the dominant transmission contingency at the West of Nicola cut-plane. The transfer capability is not adequate to deliver the entire generation surplus from Nicola substation to Lower Mainland unless a generation shedding scheme is applied in real-time operation.

As the discussion in Section 7.2.2 for double contingencies, loss of 5L75 and 5L77 simultaneously is the worst double contingency in BCTC system. An automatic load shedding scheme will be required to secure BCTC transmission system and reduce the potential impacts to the WECC interconnection system.

7.2.3 Option 1-3: 50% Series compensation on 5L91, 5L98, 5L76/79 and 5L96

This is an option of combining Option 1-1 and Option 1-3. These system reinforcements can improve the firm (post-contingency) transfer capabilities to 2700 MW at the West of Selkirk cut-plane and 4553 MW at the West of ACK/VAS cut-plane limited by voltage stability/security. This option will provide adequate transmission capabilities to transfer the generation surplus (in MCR) in South Interior area to the Interior to Lower Mainland system and meet the transmission requirements in Table 7.1.

7.3 System Reinforcement Options Based on Option 2 in Section 6

In the Option 2 in section 6, Downie substation and a 500 kV line from Downie to Revelstoke are proposed, which are much beneficial to the integration of Revelstoke Unit 6. On the base of this system configuration, two system reinforcement options are studied.

7.3.1 Transfer Demand Analysis

With the sixth unit addition in Revelstoke, the forecast transfer demands in 2018 are summarized in Table 7.2.

Table 7.2 Transfer Demands for Revelstoke Unit 6 (MW) in 2018

Cut-Plane	With Heavy Winter Load after REV G6	With Heavy Summer Load after REV G6	With Heavy Winter Load including DSBR after REV G6
West of Selkirk	2165	2303	2460
West of Downie, Ashton Creek and Vaseux Lake	6882	4651**	5786*
West of Nicola	6575	4047**	5516*

Note: * Three units in Mica are dispatched “off” with Full CE return. **Mica Plant has the minimum generation output.

According to the Table 7.2, the transfer demands at the West of Downie, Ashton Creek & Vaseux Lake cut-plane and the West of Nicola cut-plane are critical during winter peak load condition, because some units are required to be off during the off-load conditions or the return of CE is scheduled.

7.3.2 Option 2-1: 50% series compensation of 5L98 and one 500 kV 250 MVAR MSC at Nicola substation

Project Scope:

On the base of system configuration after Mica unit 5&6 addition, 50% series compensation on 5L98 and one new 500 kV 250MVAR MSC bank are proposed to accommodate the system integration of Revelstoke Unit 6. The project includes:

- One 500 kV 250 MVAR Mechanically Switched Capacitor (MSC) bank at Nicola substation. This is the first 500 kV MSC bank at Nicola.
- 50% series compensation of 5L98.
- Thermal upgrades on 5L71 and 5L72 to about 3150 Amps in summer.
- Thermal upgrade at Nicola terminals of 5L71 and 5L72 to 3150 Amps

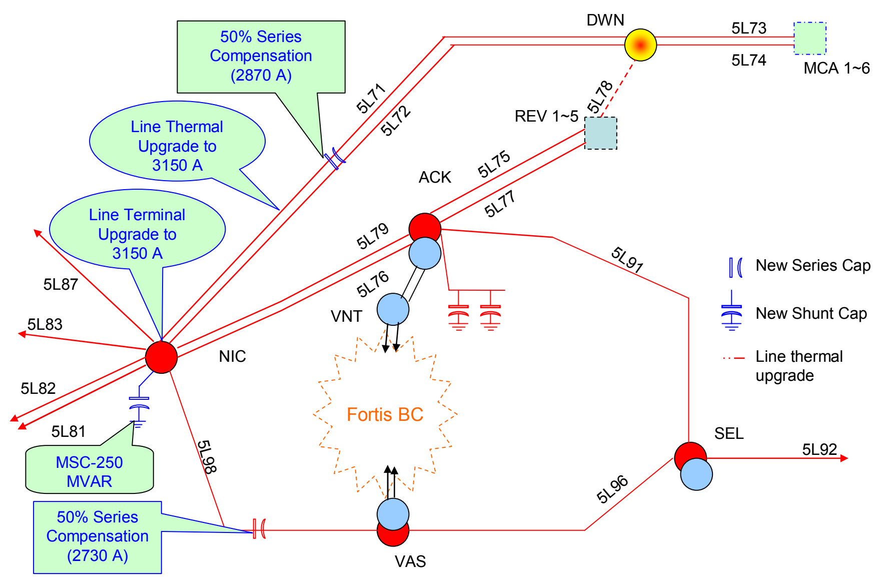

Figure 7.3 Transmission Requirements Option 2 for MCA G5&6 Integration

Transfer Capability:

This system reinforcement option is able to increase the transfer capability at the West of DWN/ACK/VAS to 6704 MW (pre-contingency) / 6634 MW (post-contingency), limited by voltage stability during 5L71 (or 5L72) contingency, they are not adequate for the transfer demands in Table 7.2. Therefore, the series compensation level at 5L71 and 5L72 will be suggested to be about 60% from Downie substation to Nicola substation; then the associated transfer capabilities at the West of DWN/ACK/VAS will be 6848 MW (pre-contingency) / 6785 MW (post-contingency), which are adequate marginally to deliver the SI generation surplus to ILM system under the winter peak condition.

These system reinforcements will provide 2258 MW (pre-contingency) / 1944 MW (post-contingency) of transfer capabilities at the West of Selkirk cut-plane, which are limited by voltage deviation after 5L96 contingency. Obviously, this option is not able to provide adequate transfer capability for the return of CE at the Eastern Inter-tie. Without the consideration of CE return, generation re-dispatch is required to address the 5L96 permanent outage.

7.3.3 Option 2-2: 50% series compensation of 5L98 & 5L91 and one 500 kV 250 MVAR MSC at Nicola substation

Project Scope:

On the base of system configuration after Mica unit 5&6 addition, 50% series compensation on 5L91 and 5L98, and one new 500 kV MSC bank are proposed to accommodate the system integration of Revelstoke Unit 6. The project includes:

- One 500 kV 250 MVAR Mechanically Switched Capacitor (MSC) bank at Nicola substation. This is the first 500 kV MSC bank at Nicola.
- 50% series compensation on 5L91 and 5L98.
- Thermal upgrades on 5L71 and 5L72 to about 3170 Amps in summer.

- Thermal upgrade at Nicola terminals of 5L71 and 5L72 to 3170 Amps

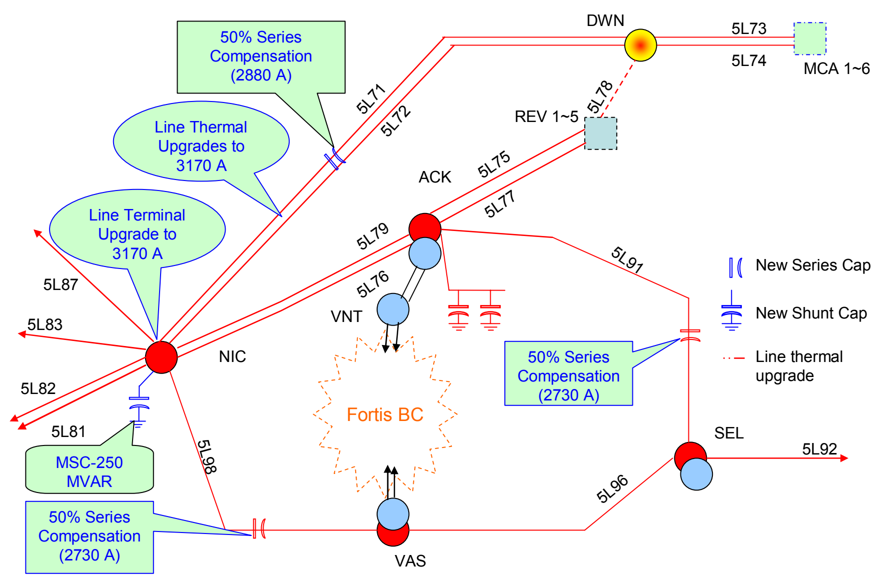

Figure 7.4 Transmission Requirements Option 2 for MCA G5&6 Integration

<u>Transfer Capability:</u>

These system reinforcements as described in the Project Scope are capable of increasing the transfer capability at the West of DWN/ACK/VAS to 6704 MW (pre-contingency) / 6634 MW (post-contingency), limited by voltage stability during 5L71 (or 5L72) contingency. It is similar as the Option 2-1, the series compensation level at 5L71 and 5L72 will be suggested to about 60% from Downie substation to Nicola substation; then the associated transfer capabilities at the West of DWN/ACK/VAS will be 6800 MW (pre-contingency) / 67840MW (post-contingency), which are marginally adequate to deliver the SIE generation surplus to ILM system under the winter peak condition.

These system reinforcements will provide 2325 MW (pre-contingency) / 2160 MW (post-contingency) of transfer capabilities at the West of Selkirk cut-plane, which are limited by voltage stability during 5L96 contingency and marginally adequate when CE return is not considered.

8 SUMMARY OF SYSTEM REINFORCEMENT OPTIONS IN SOUTH INTERIOR

By 2014, besides Mica Unit 5 and Mica Units 6, about 247 MW of nominated generation capacity will be added in Selkirk area and East Kootenay area in BC Hydro’s Contingency Resource Plan 2 (CRP2). The equivalent dependable capacity is about 84 MW because most of them are intermittent resources. In addition, the return of Canadian Entitlement (CE) is nominated as network resource and three fourteenth of CE could be scheduled at the Eastern Inter-tie. In order to achieve adequate transfer capability at the West of Selkirk cut-plane, the series compensation on 5L91 and 5L98 (SISC project) is addressed in Section 5. However, for the following considerations, this system reinforcement option is not justified yet for the project implementation before 2014:

1) In Selkirk area and East Kootenay area, the nominated generation capacity (or Maximum Continuous Rating (MCR)) is about 703 MW higher than the dependable generation capacity in 2014.

2) The historical records show that the peak transfer at the West of Selkirk cut-plane appears under light load condition during Freshet time period. Generation re-dispatch may be applied to address the transmission constraint after transmission contingencies during the lighter load period.

3) When the return of CE is necessary to be scheduled at the Eastern Inter-tie for BC system resource adequacy, generation offset at Selkirk area could alleviate the transmission constraint at the West of Selkirk cut-plane after transmission contingencies.

8.1 South Interior Transmission System Development Sequences

As the peaking units, Mica Unit 5 (480 MW), Mica Unit 6 (480 MW) and Revelstoke Unit 6 (500 MW) have been scheduled to enter service in 2013, 2014 and 2018 respectively in CRP2. Considering new IPP interconnections in South Interior in next 20 years, two transmission system reinforcement sequences are summarized as follows from the system study results in Section 6 and Section 7.

8.1.1 System Reinforcement Sequence 1 (SRS-1)

This system reinforcement sequence, SRS-1 does not consider any new construction of 500 kV substation and new 500 kV transmission lines. The fixed level series compensation and mechanically switched shunt capacitor(s) are employed to improve system voltage stability. The major projects proposed in SRS-1 are:

1) Build series capacitor station around the mid-line point with 50% (up to 55%) series compensation to 5L71 and 5L72 in October 2013 to accommodate the Mica Unit 5 interconnection.

   If the project definition phase is approved in F2010 Capital Plan and will be commenced in May 2009, the available project lead time is too short and the system reinforcement project may not be completed by October 2013.

2) Install one 500 kV MSC bank (about 250 MVAR) at Nicola in October 2014 to accommodate the Mica Unit 6 interconnection. In addition, a load shedding RAS is required in real-time operation to protect the transmission system during 5L71/5L72 double contingency;

3) Build series capacitor station on 5L91 and series capacitor station on 5L98 with 50% series compensation level; and install the second 500 kV MSC bank (about 250 MVAR) at Nicola substation in October 2018. In addition, a load shedding RAS is required in real-time operation to address the 5L75/5L77 double contingency.

   The series compensation on 5L91 and 5L98 project is named as South Interior Series Compensation (SISC) project and presently in project definition phase. This project was once proposed to accommodate Waneta Expansion interconnection. If Waneta Expansion enters service before Revelstoke Unit 6, the alternative system reinforcements for Revelstoke Unit 6 in this sequence will be: i) build series capacitor station on 5L76/5L79 with 50% series compensation level and ii) build the series capacitor station on 5L96 with 50% series compensation level in October 2018.

8.1.2 System Reinforcement Sequence 2 (SRS-2)

In the SRS-2, new switching station in Downie Creek area and a new transmission line 5L78 from Downie station to Revelstoke plant are proposed to reduce the opportunities of losing Mica plant or Revelstoke plant entirely during double contingencies. Due to the obvious cost-effectiveness, the 500 kV line from Downie station to Mica is not proposed in this sequence. The major projects proposed in this sequence are:

1) Build series capacitor station around the mid-line point with 40% series compensation to 5L71 and 5L72 in October 2013 to accommodate the Mica Unit 5 interconnection.

   If the project definition phase is approved in F2010 Capital Plan and will be commenced in May 2009, the available project lead time is too short and the system reinforcement project may not be completed by October 2013.

2) Build new 500 kV switching station at Downie Creek area and new 500 kV transmission line 5L78 from Downie station to Revelstoke Plant (~ 60 km) in October 2014. In addition, a load-shedding RAS may be required to address the 5L73/5L74 double contingency. Generation shedding RAS's will be required to address the double contingencies such as 5L71/5L72 outage and 5L75/5L77 outage.

   It will be very difficult or may be impossible to complete the new line construction within five (5) years according to the experience of 5L83 project development.

3) Build series capacitor station on 5L91 and series capacitor station on 5L98 with 50% series compensation level; and install one 500 kV MSC bank (about 250 MVAR) at Nicola substation in October 2018.

8.2 Preliminary Cost Estimate and Economic Comparison

Cost estimate is not required in the System Impact Study stage according to BCTC Open Access Transmission Tariff (OATT), but the preliminary option cost estimates are very helpful for recommending the system reinforcement solution based on preliminary economic comparison among the different system reinforcement options.

The cost estimates of transmission line thermal upgrades and line terminal thermal upgrades are not included yet in this economic comparison because more detailed engineering works are required. The thermal upgrade projects will be addressed in detail in Facility Study stage.

8.2.1 Cost estimation

Preliminary cost estimates[4] are prepared for the usage of economic comparison only and the associated direct capital costs are summarized in the Table 8.1 and Table 8.2. The expected project total capital cost will include additional inflation and interest during construction (IDC).

Table 8.1 Cash-flow for the sequence SRS-1

Item No.	System Reinforcement Project	Cash Flow in thousands of Dollars (Un-inflated construction cost plus OH)											
		Total	F2009	F2010	F2011	F2012	F2013	F2014	F2015	F2016	F2017	F2018	F2019
1	50% Series Compensation on 5L71 and 5L72	44,721	221	396	1,216	1,360	9,362	32,166					
2	500kV MSC Bank(1*250 MVAR) at Nicola Substation	5,164					520	818	3,826				
3	50% Series Compensation on 5L91 and 5L98	48,636	1,440							1,204	3,414	16,420	26,158
4	500kV MSC Bank(1*250 MVAR) at Nicola Substation	5,164									520	818	3,826
5	SRS-1 in Total	103,685	1,661	396	1,216	1,360	9,882	32,984	3,826	1,204	3,934	17,237	29,985

Table 8.2 Cash-flow for the sequence SRS-2

[4] The cost estimate is un-inflated construction cost in 2007 dollars plus corporate overhead

Item No.	System Reinforcement Project	Cash Flow in thousands of Dollars (Un-inflated construction cost plus OH)											
		Total	F2009	F2010	F2011	F2012	F2013	F2014	F2015	F2016	F2017	F2018	F2019
1	40% Series Compensation on 5L71 and 5L72	36,225	221	396	1,216	1,360	9,362	23,670					
2	Downie 500 kV Substation	38,331			542	712	2,066	11,497	23,513				
3	500 kV transmission line from Downie to Revelstoke (58 km)	114,098	1,119	2,684	5,689	20,887	24,838	33,723	25,159				
4	50% Series Compensation on 5L91 and 5L98	48,636	1,440							1,204	3,414	16,420	26,158
5	500kV MSC Bank(1*250 MVAR) at Nicola Substation	5,164									520	818	3,826
6	SRS-2 in Total	237,290	2,780	3,080	7,447	22,959	36,266	68,890	48,672	1,204	3,414	16,420	26,158

8.2.2 Economic comparison

When simply comparing the un-inflated construction cost, the SRS-2 is extremely expensive and more than double of the SRS-1 cost.

The present value (PV) of the SRS-1 is about $69.6M while the PV of the SRS-2 is about $173.4M.

The SRS-1 could be the recommended solution according to the economic comparison result.

9 CONCLUSIONS AND RECOMMENDATIONS

This report assesses several transmission system reinforcement options to integrate the peaking units, Mica Unit 5, Mica Unit 6 and Revelstoke Unit 6, including series compensation to the existing 500 kV transmission lines, shunt capacitors at 500 kV substations, new switching station and new transmission lines. Consequently, two system reinforcement sequences have been summarized in SRS-1 and SRS-2. The System Reinforcement Sequence 1 (SRS-1) is recommended to accommodate the system integrations of Mica Units 5, Mica Unit 6 and Revelstoke Unit 6 in this report based on the key assumption that Remedial Action Schemes (RAS) such as post-contingency load shedding are allowable and acceptable for the severe and rare double contingencies.

Station Planning and P&C Planning are not involved directly in this stage and will provide more technical inputs during the Facility Study stage. More engineering investigations will be conducted on the transmission line thermal upgrades and line terminal equipment replacements in Facility Study stage and faithful project cost estimates will be provided in the Facility Study report.

Appendix A

British Columbia Hydro and Power Authority

Network Integrated Transmission Service

OASIS Transmission Request #71699426

(31 August 2010 to 01 October 2014)

System Impact Study Agreement

British Columbia Transmission
CORPORATION™

November 16, 2007

Pat Harrington
British Columbia Hydro and Power Authority
333 Dunsmuir Street, 10th Floor (D-10)
Vancouver BC V6B 5R3

Re: System Impact Study Agreement for Network Integrated Transmission Service OASIS Request No. 71699426

Dear Pat:

BCTC has determined that System Impact Study is required to accommodate your request. We hereby tender the enclosed System Impact Study Agreement for your consideration.

Pursuant to Section 32.1 of BCTC's OATT, British Columbia Hydro and Power Authority has 15 days to execute this System Impact Study Agreement to maintain its position in the queue. Please sign in duplicate and return all copies to my attention by December 01, 2007.

Please call me at (604) 699-7385 if you have any questions.

Yours truly,

Anne Wong

Anne Wong
Transmission Contracts Specialist

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Transmission Reservation Detail 71699426 STUDY

Seller	Source Sink	POR POD	Request Type	Start	Stop	MW Req	MW Grant	Bid Price	Offer Price	Ceiling Price	Price Unit
BCTC		BCTC.NETWORK BCTC.NTWK.LD	ORIGINAL	2010-08-31 00:00 PD	2014-10-01 00:00 PD	2046		0.00		0.00	$CDN
Path: W/BCTC/INTERNAL//											

Service Code	Increment	Class	Type	Period	Window	Subclass
YRLY_FIRM_NETWRK_EXTENDED	YEARLY	FIRM	NETWORK	FULL_PERIOD	EXTENDED	

Preconfirmed: No	Competing: No	Negotiated: No	Nerc Priority: 1	Affiliate: No

Reservation Profile

Start Date	Stop Date	MW Req	MW Grant	MWH	Bid Price	Offer Price
2010-08-31 00:00 PD	2014-10-01 00:00 PD	2046		73263168.00	0.00	
			Profile Total:	73263168.00		

Times		References	
Queued	2007-11-05 11:56:17 PS	Deal	
Updated	2007-11-26 16:08:27 PS	Sale	
Response		Posting	
		Request	
Impacted	0	Reassigned	
Last Customer Action	2007-11-05 11:56:17 PS	Seller	
Last Seller Action	2007-11-26 16:08:27 PS	Related	

Comments	
Status	
Seller	
Provider	
Customer	Designation of new Network Resources (REV G6 & MCA G6) and update to REV G5 and MCA G5.

Status Notification	
Anc-Service-Link	

Customer: BCHD		Seller: BCTC	
Name	pharring	Name	AnneWong
Phone	604-623-4285	Phone	
Fax	604-623-4335	Fax	
E-mail	pat.harrington@bchydro.com	E-mail	anne.wong@bctc.com

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Transmission Reservation Detail 71699426 RECEIVED

Seller	Source Sink	POR POD	Request Type	Start	Stop	MW Req	MW Grant	Bid Price	Offer Price	Ceiling Price	Price Unit
BCTC		BCTC.NETWORK BCTC.NTWK.LD	ORIGINAL	2010-08-31 00:00 PD	2014-10-01 00:00 PD	2046		0.00		0.00	$CDN
Path: W/BCTC/INTERNAL//											

Service Code	Increment	Class	Type	Period	Window	Subclass
YRLY_FIRM_NETWRK_EXTENDED	YEARLY	FIRM	NETWORK	FULL_PERIOD	EXTENDED	

Preconfirmed: No	Competing: No	Negotiated: No	Nerc Priority: 1	Affiliate: No

Reservation Profile

Start Date	Stop Date	MW Req	MW Grant	MWH	Bid Price	Offer Price
2010-08-31 00:00 PD	2014-10-01 00:00 PD	2046		73263168.00	0.00	
			Profile Total:	73263168.00		

Times		References	
Queued	2007-11-05 11:56:17 PS	Deal	
Updated	2007-11-05 11:56:45 PS	Sale	
Response		Posting	
		Request	
Impacted	0	Reassigned	
Last Customer Action	2007-11-05 11:56:17 PS	Seller	
Last Seller Action	2007-11-05 11:56:45 PS	Related	

Comments	
Status	
Seller	
Provider	
Customer	Designation of new Network Resources (REV G6 & MCA G6) and update to REV G5 and MCA G5.

Status Notification	
Anc-Service-Link	

Customer: BCHD		Seller: BCTC	
Name	pharring	Name	BCTC_TSS
Phone	604-623-4285	Phone	
Fax	604-623-4335	Fax	
E-mail	pat.harrington@bchydro.com	E-mail	

Done Internet

Appendix B

Thermal Ampacity of SI 500kV Transmission Lines

Thermal Rating of the Transmission Lines

	Thermal in Summer (30 degree C)		Thermal in Winter (10 degree C)		Thermal in Winter (0 degree C)	
	Continuous	Overload	Continuous	Overload	Continuous	Overload
5L91	3540 Amps	3370 Amps	4284 Amps	4075 Amps	4522 Amps	4302 Amps
5L98	3506 Amps		4241 Amps		4475 Amps	
5L96	3506 Amps		4241 Amps		4475 Amps	
5L71	2265 Amps	3370 Amps	3302 Amps	4072 Amps	3603 Amps	4302 Amps
5L72	2265 Amps	3370 Amps	3302 Amps	4072 Amps	3603 Amps	4302 Amps
5L75	2870 Amps	3370 Amps	3700 Amps	4072 Amps	3965 Amps	4302 Amps
5L77	2265 Amps	3370 Amps	3302 Amps	4072 Amps	3603 Amps	4302 Amps
5L76	2265 Amps	3370 Amps	3302 Amps	4072 Amps	3603 Amps	4302 Amps
5L79	3501 Amps		4238 Amps		4522 Amps	

Notes:

Thermal upgrade is needed in summer to approximate 91 degree C
Conductor 4-666.9 MCM AACSR
Conductor 4-666.9 MCM ACSR
Conductor 4-648.2 MCM ACSR