Appendix

6F

Transmission Analysis
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1 Introduction

One of the Clean Energy Act (CEA) requirements for this Integrated Resource Planning (IRP) process is to provide a description of BC Hydro’s 20- to 30-year needs for expansion of the transmission grid including a geographical assessment of the potential for developing clean or renewable resources in B.C. This document assesses bulk transmission requirements at the portfolio level for integrating new resources to serve the forecasted demand under a range of load/resource combinations and the transmission requirements to group geographically coherent generation plants into clusters of resources connecting to a new central substation hub.

This appendix provides the following:

- An overview of the BC Hydro’s bulk transmission network;
- An introduction to the IRP cluster analysis;
- A description of the transmission analysis methodology for 20- and 30-year planning horizons;
- The identified solutions for removing transfer constraints and expanding the bulk transmission network.

2 Overview Of The Transmission System

BC Hydro owns and operates a transmission network which is part of the western North American grid. The grid extends from B.C. and Alberta in the north, to northern Mexico in the south. Interties to neighboring systems provide opportunities for electricity trade and improve the overall reliability of the system. BC Hydro is a member of the Western Electricity Coordinating Council (WECC).

BC Hydro’s transmission system consists of:
(a) 18,589 km of transmission circuits;
(b) 292 switching, distribution and capacitor stations;
(c) a System Control Centre located in the Lower Mainland;
(d) a back-up Control Centre located in the B.C. Interior;
(e) 153 microwave and fibre-optic sites; and
(f) BC Hydro’s portion of interties to Alberta and the U.S. Pacific Northwest and internal interties to FortisBC and to Rio Tinto Alcan (RTA).

For planning purposes, BC Hydro defines the transmission system to be made up of:

(a) the bulk transmission system;
(b) the regional transmission system;
(c) BC Hydro’s portion of the internal interties to the RTA system and the FortisBC system;
(d) BC Hydro’s portion of the external interties to systems in Alberta and Washington State; and
(e) a comprehensive communication, protection, and control system.

The main focus of this document is on BC Hydro’s bulk transmission network and the interties to Alberta and the U.S. The bulk transmission network is planned for reliable transfer of power from generation resources to the regional transmission and distribution networks and to the neighboring networks. This network consists of all 360 kV to 500 kV circuits and a select number of 230 kV to 287 kV circuits.

The regional transmission network delivers power to the major load customers as well as the distribution network. It includes transmission circuits at voltages ranging from 60 kV to 230 kV. Historically, the scope of the transmission analysis in integrated resource planning processes has been limited to the above defined bulk transmission grid. Review and expansion of BC Hydro’s regional transmission
network are conducted on an ongoing basis and their results are reflected in the BC Hydro’s expansion plans. However, due to the significance of the potential expansion of regional transmission networks in Fort Nelson, the North Coast and the South Peace River and their potential impact on the bulk transmission grid, these regional projects are addressed in this IRP.

3 Bulk Transmission System

Figure 1 shows BC Hydro’s existing bulk transmission network including its major substations. It includes the 500 kV system, parts of the 230 kV system, the transmission connections to Vancouver Island, and interconnections with other systems. These lines connect the large, remote generating stations in the Peace River and Columbia River areas with the major load centers of the Lower Mainland and Vancouver Island, which represent over 70 per cent of BC Hydro’s load.

For planning purposes, BC Hydro’s bulk transmission network is subdivided into four systems: the Northern System, the South Interior, the Interior to Lower Mainland (ILM), and the Lower Mainland to Vancouver Island systems. Planning for the bulk system is informed by BC Hydro’s system load and generation forecasts and by customers holding or requesting transmission service under the Open Access Transmission Tariff. Bulk system planning is performed in accordance with the framework of the Mandatory Reliability Standards approved by the British Columbia Utilities Commission (BCUC)\(^1\).

As demand for energy increases over time, the flow of electricity from one region of the province to another can become constrained by the existing capacity of the transmission network. To assess timing and magnitude of such constraints and to assign appropriate transmission solutions for removing them, transmission cut-planes are used. Transmission cut-planes are imaginary lines which cut through one or more transmission paths. They show the direction and limits of power flow

\(^1\) The applicable BCUC approved NERC standards are: TPL1, TPL2, TPL3, and TPL4.
and are used to identify possible bottlenecks of the bulk transmission network. Figure 2 shows the major transmission cut-planes in BC Hydro’s bulk transmission network.

Figure 1  BC Bulk Transmission System
3.1 Northern System

Figure 3 shows the northern transmission system, including the major Peace River generating region in the northeast, the main transmission lines to Williston Substation (WSN) near Prince George, and the transmission lines from Williston to Kelly Lake Substation (KLY) near Clinton. It also includes the radial 500 kV transmission from WSN to Skeena Substation (SKA), which connects the main grid to the North Coast. Figure 3 also shows the northern system’s regional transmission network including:

- Peace region to Williston;
- Williston to Kelly Lake;
- And Williston to the North Coast.
The regional transmission is not further discussed in this document.

Figure 3  Northern Region Transmission
The northern bulk transmission system transmits energy from the G.M. Shrum (GMS) and Peace Canyon (PCN) generating facilities near Fort St. John southward to the Central Interior region of B.C. connecting with the ILM system at KLY Substation. The Northern System also transmits energy to or from the North Coast, depending on whether Rio Tinto Alcan is importing energy from the system or exporting the energy it produces at its Kemano generating facility.

The Northern System can be viewed as three distinct subsystems: Peace to Williston, Williston to Kelly Lake, and Williston to North Coast.

### 3.1.1 Peace Region to Williston System

The capacity of the Peace to Williston transmission path (the South of GMS cut-plane) is limited to 3,590 MW south of Kennedy Substation (KDY) during winter peak load conditions. This is a voltage stability limit and can increase to 3,620 MW under light winter load conditions.

The amount of additional transfer capacity required on this path will depend on the future generation additions and load variations in the area. Preliminary studies indicate that addition of a 250 MVAr/500 kV shunt capacitor bank at KLY and a 300 MVAr Static VAr Compensator (SVC) and two 250 MVAr/500 kV shunt capacitor banks at WSN will increase the voltage stability limits by 580 MW.

Should a larger increase in the transmission capacity be required, a new transmission line from GMS to WSN (5L8) would add another 1,470 MW to the above 580 MW. Figure 4 illustrates potential transmission along the GMS-WSN-KLY transmission corridor including a new transmission line (5L14) from WSN to KLY.
3.1.2 Williston to Kelly Lake System

Transmission capacity of the Williston to Kelly Lake path (the South of Williston cut-plane) is limited by voltage stability to 3,060 MW in heavy winter and 3,340 MW in light winter load conditions. Preliminary studies indicate that the existing capacity in the Williston to Kelly Lake System is enough to serve the additions of the new dependable generation developed, including generation from BC Hydro’s F2006 Open Call for Power and power flow from RTA.

Further generation additions in the Peace region and North Coast, such as those in the Clean Power Call may require transmission capacity additions. The addition of the same shunt capacitor banks and SVC identified above will also increase the voltage stability limits by 650 MW.
Should a larger increase in the transmission capacity be required, 5L8 plus a new transmission line from WSN to KLY (5L14) will increase the transfer capacity on the South of Williston cut-plane by 2,120 MW (refer to Figure 4).

3.1.3 Williston to North Coast System

A cascade of three 500 kV circuits; 5L61 from Williston to Glenannan (GLN), 5L62 from GLN to Telkwa (TKW), and 5L63 from TKW to SKA creates a radial path to connect the Central Interior transmission network to the North Coast. For the east to west flows from WSN towards SKA, this path is referred to as the West of Williston cut-plane. For the west to east flows, the path is referred to as the East of Skeena cut-plane. Currently, power flows either to or from the North Coast depending on whether RTA is importing or exporting energy.

The potential for Liquefied Natural Gas (LNG) and mining facilities in the North Coast region has renewed the interest in reviewing the capacity of North Coast bulk transmission system. The incremental LNG and mining loads can be as high as 1,500 to 2,000 MW. Should these loads be supplied from the BC Hydro grid, the WSN-GLN-TKW-SKA 500 kV transmission path will become congested. To remove the constraint, incremental transmission capacity provided by reinforcements to both the WSN-GLN-TKW-SKA corridor and regional North Coast transmission facilities will be required.

The existing West of Williston cut-plane capacity is limited to 695 MW due to voltage stability constraints during heavy winter loads. Transfer capability of the East of Skeena cut-plane is limited to 1,000 MW because of transient stability constraints during light summer loads.

The addition of the Northwest Transmission Line (NTL) in May 2014 and reactive compensation of North Coast regional transmission is expected to increase the North Coast load serving capability to approximately 800 MW. The addition of series
compensation of 5L61, 5L62, and 5L63 plus two 500 kV shunt capacitors at TKW would increase the load serving capability in the North Coast region to 1,380 MW.

The next stage of east-to-west capacity increase can be achieved by adding a new 500 kV series and shunt compensated WSN-GLN-TKW-SKA circuit. This network addition will allow North Coast loads up to 2,350 MW to be served from WSN. Should the net North Coast load exceed this level, other solutions such as a new +/-500 kV HVDC bipole would have to be considered. Figure 5 shows the potential AC upgrades along the WSN-GLN-TKW-SKA transmission corridor.

Figure 5  North Coast Transmission Upgrade Options
3.1.3.1 **Northwest Transmission Line**

The NTL is an approximately 344 km, 287 kV transmission line between Skeena Substation (near Terrace) and a new substation to be built near Bob Quinn Lake. The new line (as shown in Figure 6) will:

- Provide a reliable supply of clean power to potential industrial developments in the area;
- Provide a secure interconnection point for clean generation projects;
- Assist certain northwestern B.C. communities to access the electricity grid, rather than obtaining their power from diesel generators.

The NTL is a $404 million project. In 2009, the Federal government committed $130 million under the Green Infrastructure Fund to assist in the development of the project. The application for an Environmental Assessment Certificate (EAC) for the project was submitted in January 2010 and an EAC was issued in February 2011. The expected in-service date of the NTL project is in the spring of 2014.

![Northwest Transmission Line Diagram](image-url)
3.2 South Interior System

Approximately half of BC Hydro’s generation resources are located in the South Interior. The South Interior transmission system transfers energy generated in the Columbia and Kootenay regions, plus imported energy from the U.S. and Alberta. The energy flows west to the ILM System at Nicola Substation (NIC) near Merritt. The South Interior System is also used to deliver FortisBC energy from the Kootenay area to the Okanagan under the General Wheeling Agreement.

Figure 7 shows the existing bulk transmission network in South Interior. It also shows much of the regional transmission system, which is not discussed in this document.
The Revelstoke and Mica generating stations connect directly into the 500 kV South Interior transmission system. The Kootenay Canal (KCL), Seven Mile (SEV), and Arrow Lakes generating stations are integrated into the 230 kV system. Other hydroelectric generating stations in the southeast are connected to the FortisBC system. Their power flows towards Selkirk Substation (SEL) near Trail. The majority of generation in the southeast is transformed from 230 kV to 500 kV at SEL.

The South Interior transmission system can be divided into two subsystems which connect at Selkirk:

- The system from the lower Columbia area west to Nicola (South Interior West) and
- The upper Columbia area east to Alberta (South Interior East).

### 3.2.1 South Interior West

The energy hub of the South Interior West system is the Selkirk Substation. SEL collects most of the energy generated in the Trail area and injects it into the 500 kV bulk transmission system towards NIC. From NIC, the South Interior West energy flows towards the Lower Mainland and Vancouver Island on the ILM cut-plane. Major transmission cut-planes in the South Interior West are:

(a) The West of Selkirk cut-plane which is limited by voltage stability constraints to 1,910 MW and 2,320 MW during heavy winter and heavy summer load conditions respectively;

(b) The West of Selkirk/Ashton Creek cut-plane which is limited by voltage stability constraints to 3,270 MW and 4,020 MW during heavy winter and heavy summer load conditions respectively;

(c) The Mica to Nicola cut-plane which is limited by voltage stability constraints to 1,650 MW under all load conditions;
(d) The Revelstoke to Ashton Creek cut-plane which is limited by thermal constraints to 3,000 MW and 2,060 MW during winter and summer load conditions respectively.

For small increments of transmission capacity from SEL to NIC, 50 per cent series compensation of 5L91 and 5L98 would add 133 MW to the transfer capacity of the SEL to NIC transmission (5L96 and 5L98) and 147 MW to the transfer capacity of the West of Selkirk/Ashton Creek cut-plane. Also, 50 per cent series compensation of 5L96 and 5L76 and 5L79 would increase transfer capability of these paths by 112 MW. To achieve up to 1,500 MW of incremental transmission capacity between SEL and NIC, new 500 kV lines between SEL and Vaseux Lake Substation (VAS) and between VAS and NIC would be required.

Previous studies indicated that, to provide adequate voltage support for integrating new Mica Units 5 and 6 into BC Hydro’s bulk transmission network, both circuits 5L71 and 5L72 have to be series compensated. Mica Units 5 and 6 will be installed in 2014 and 2015 respectively. In October 2014, the Mica to Nicola cut-plane capacity will be increased by 624 MW after the addition of 50 per cent series compensation to circuits 5L71 and 5L72.

To achieve higher amounts of transfer capability from SEL towards NIC substations, new series compensated 500 kV transmission lines between SEL and VAS (5L97) and between VAS and NIC (5L99) have to be built. Figure 8 shows the possible South Interior West transmission additions.
3.2.2 South Interior East

Figure 9 provides a map of the South Interior East system. Energy is transferred eastward from SEL to Cranbrook (CBK) to serve local area load. Energy is then transmitted further east from CBK to Alberta over the B.C.-Alberta Intertie. Energy also flows from Cranbrook to Natal Substation, which is also connected by two 138 kV lines to the Alberta system.

The capacity of the South Interior East system is limited by the transfer capability of the 5L92 and 5L94 circuits. These lines provide adequate capacity for the current...
level of power transfers between Alberta border, CBK, and SEL. Should additional 200 MW to 600 MW of transfer capability be required, series compensation of these lines can be considered. The ultimate upgrade of the South Interior East system will be addition of new 500 kV lines parallel to 5L92 and 5L94. This will increase the transfer capability by about 1,500 MW.

Figure 9 Southern Interior East – Transmission

3.3 Interior to Lower Mainland System

The ILM network is the most critical transmission path in the province. The ILM transmits energy from the B.C. Interior, where the majority of generation is located, to the Lower Mainland (LM) substations. Part of the transferred power is delivered to Vancouver Island (VI) loads through the LM to VI cut-plane. The ILM is also a key transmission path for energy trading activities.
The ILM System is comprised of eight 500 kV lines. These are 5L40, 5L41, 5L42, 5L44, 5L45, 5L81, 5L82, and 5L87. The ILM bulk system is supported by a 360 kV line from Bridge River Generation to the Fraser Valley and several 230 kV lines that carry power from Bridge River to the Lower Mainland. The power transfer from the Interior to the Lower Mainland takes place over 5L41, 5L42, 5L81, and 5L82 as well as the regional 360 kV and 230 kV lines. Circuits 5L40, 5L44, and 5L45 allow power sharing between four 500 kV substations located in the LM: Cheekye (CKY), Ingledow (ING), Meridian (MDN) and Clayburn (CBN). Circuit 5L87 interconnects the KLY and NIC.

The transfer capability of the ILM system is constrained by both thermal and voltage stability limits. To remove these constraints, in August 2008, the BCUC granted a Certificate of Public Convenience and Necessity (CPCN) to construct a new series-compensated 500 kV line (5L83) between NIC and MDN substations. The Environmental Assessment Certificate for 5L83 was issued by the Province in June 2009. Currently, the expected in-service date for the new line is January 2015. This line will increase the continuous thermal rating and voltage stability limit of the ILM system to 6,750 MW and 6,550 MW respectively.

Should there be a need for further increase of the ILM 6,550 MW voltage stability limit, new shunt capacitors can be added at NIC 500 kV and MDN 230 kV substations. This will increase voltage stability limit of the ILM grid to 7,120 MW. Further increase of the ILM transfer capability would require thermal upgrades of the existing series capacitor banks or a new transmission circuit. One possible new line option is a 500 kV series compensated circuit between Kelly Lake and Cheekye substations (5L46). This circuit would add approximately 1,380 MW to the ILM transfer limit (refer to Figure 10).
3.4 Lower Mainland to Vancouver Island System

Vancouver Island and the southern Gulf Islands are supplied by a combination of local generation and power delivered via submarine cable circuits crossing Georgia Strait. The two 500 kV submarine cables from Malaspina Substation (MSA) near Pender Harbour to Dunsmuir Substation (DMR) near Qualicum provide a key source of supply to Vancouver Island with a combined firm capacity of 1,400 MW in winter.
and 1,300 MW in summer. These cables are in good working conditions and are expected to function during the 20-year planning horizon.

The 230 kV Vancouver Island Transmission Reinforcement (VITR) project was completed in 2008. This project increased the firm transmission capacity between Lower Mainland and Vancouver Island to 2,000 MW in winter and 1,900 MW in summer. With the completion of VITR, the southern Gulf Islands are now normally supplied from Arnott Substation (ARN) in Delta. The next reinforcement of the supply to Vancouver Island could be a second 230 kV cable (2L124) which will add another 600 MW to the transfer capacity. The LM-VI transmission network and a possible upgrade option are shown in Figure 11.

Figure 11 Lower Mainland to Vancouver Island Transmission Upgrade Option
4 The Interties

4.1 Internal Interties

4.1.1 Rio Tinto Alcan Intertie

BC Hydro’s transmission system is connected to the Rio Tinto Alcan transmission system by a single 287 kV line from BC Hydro’s Minette Substation (MIN) to RTA’s Kitimat Substation (KIT). Depending on the time of year, and at different combinations of generation and smelter load, RTA can be either a net importer (up to 200 MW) or exporter (up to 380 MW) of power.

4.1.2 FortisBC Interties

BC Hydro’s transmission system has two main interconnections to FortisBC’s transmission system in the South Interior: the Okanagan Interconnection and the Kootenay Interconnection. The Okanagan Interconnection connects the transmission system to the FortisBC system at two locations: Vaseaux Lake Terminal Station (VAS) near Oliver and Vernon Terminal (VNT) near Vernon. The Kootenay Interconnection consists of interconnections at Kootenay Canal, Selkirk and Nelway.

BC Hydro is obligated under the General Wheeling Agreement with FortisBC to deliver FortisBC’s energy over the transmission system. This agreement requires FortisBC to nominate its wheeling (transmission) needs five years in advance. By 2014, the wheeling obligations to the Okanagan Interconnection under the General Wheeling Agreement could be as high as 600 MW.

4.2 External Interties

BC Hydro’s transmission system is interconnected with transmission systems in Alberta and in Washington State as shown in Figure 12. These interties provide trade opportunities and improve the overall reliability of the system.

The operating limits (capacity) of BC Hydro’s external interties are established through the WECC Path Rating Process. The path ratings are set by WECC.
members and define the maximum amount of power that can be transferred over a
given path under the most favorable conditions.

**Figure 12** Interties to Alberta and the U.S

![Interties to Alberta and the U.S](image)

### 4.2.1 B.C. – Alberta Intertie

As shown in [Figure 12](#), the transmission system is connected with Alberta by one
500 kV line from Cranbrook to Langdon Substation in Alberta. There are also two
138 kV lines from Natal Substation near Sparwood to the AltaLink network in
Alberta.

During high transfer conditions, a contingency event on the 500 kV line trips the two
138 kV ties. As a result, the B.C. Alberta intertie is limited to the capacity of the
500 kV line. The current WECC approved path rating for B.C. to Alberta is
1,200 MW. The current total transfer capability is constrained to 850 MW by system
limitations within Alberta.

In the Alberta to B.C. direction, the WECC approved path rating is 1,000 MW.
However, the Alberta to B.C. transfer is limited by both BC Hydro and the Alberta
Electric System Operator (AESO) to 800 MW based on present studies and the
absence of generation shedding in Alberta.
These limitations are expected to be alleviated when the transmission network between Edmonton and Calgary is reinforced. The AESO proposed the critical transmission system development between Edmonton and Calgary in its Long-term Transmission System Plan (issued in June 2009). The project has been designated as critical transmission infrastructure in the Government of Alberta’s Electric Utilities Act.

4.2.2 B.C. – U.S. Interties

The interconnection between the B.C. system and the Bonneville Power Authority (BPA) system in Washington State includes two interties: the 500 kV Westside Intertie and the 230 kV Eastside Intertie.

The Westside Intertie consists of two 500 kV lines, 5L51 and 5L52, from Ingledow substation in B.C. to BPA’s Custer Substation near Bellingham. The Eastside Intertie has two 230 kV lines. One line runs from Nelway to BPA’s Boundary Substation. The second line, owned by Teck Cominco and operated by FortisBC, is normally connected between Waneta Generating Station and Nelway, with the final section of the line from Nelway to Boundary open (i.e., not connected).

The WECC-approved path rating from B.C. to the U.S. is 3,150 MW, a combined limit for both interties, with maximum flow limited to 2,850 MW on the 500 kV Westside Intertie. The Boundary to Nelway line has a limit of 400 MW. The east side flow is controllable by the Nelway 400 MW phase-shifting transformer. The 3,150 MW limit depends on the availability of Remedial Action Schemes (RASs), including an automatic generation shedding RAS. This path rating is transient stability limited under low load conditions. The limit is lower during heavier load and outage periods.

The WECC-approved combined path rating from the U.S. to B.C. is 2,000 MW, with a maximum flow of 2000 MW on the Western Intertie and 400 MW on the Eastern Intertie. Simultaneous imports from the U.S. and Alberta may be limited to ensure
that the system has the capability to withstand a frequency dip associated with the sudden loss of high imports.

In 2007, the firm transfer capacity from the U.S. to B.C. was raised to 1,930 MW, based on the capacity available after the loss of 5L51. This provides enough firm capacity to meet demand from existing contracts, the Canadian Entitlement and Teck Cominco Entitlements.

In April 2008, the BCUC approved the Transmission Upgrade Project (TUP) for a thermal upgrade of the 500 kV circuits 5L51 and 5L52. The TUP involved the raising of existing towers along the right-of-way (RoW) between the Ingledow Substation and the B.C.-U.S. border, and re-tensioning of conductors along some sections of the RoW. The construction associated with the TUP was completed in September 2010. This project increased thermal ratings of 5L51 and 5L52 conductors to 3000 Ampere and increased the total import capability from the U.S. (on both the western and the eastern interconnections) to 3,000 MW. The increased south to north path rating increase is currently proceeding through the WECC approval process. The constraints on the U.S. side of the western interconnection, along the I-5 corridor, remain the bottleneck for the B.C.-U.S. power transfers.

5 Cluster Analysis

In the past, B.C. Hydro has planned its transmission system in response to forecast demand growth and anticipated generation projects. This approach is increasingly subject to the following risks:

- Generation projects may be completed before transmission lines are ready or may need to be delayed until lines can be completed;
- Generation projects may develop in a way that leads to a spider web of intersecting transmission lines that are inefficient and have avoidable adverse environmental footprints; and
New demand for electricity may occur sooner than transmission lines can be built to provide the service.

Pursuant to the CEA requirements to include an assessment of the potential for developing electricity generation from clean or renewable resources in B.C. grouped by geographic area and as part of the IRP analysis and ongoing planning work, BC Hydro considered where the largest potential exists for low-cost clean generation options. Rather than responding to individual projects, this planning process identifies where clusters of projects could appear across the province (i.e., regions with a combination of run-of-river, wind or biomass potential) and the costs, benefits and risks of pre-building transmission to access these generation clusters.

The IRP cluster analysis considers the following questions:

- What are the benefits and costs of pre-building transmission to areas with high concentration of generation resources? In addition to financial considerations, other potential benefits could include minimizing environmental footprint through avoiding an excessive number of transmission corridors in an area or fostering economic development in an area.

- What are the risks associated with pre-building transmission in advance of generation project development? One key risk factor is that transmission investment may be stranded if generation resources do not develop as expected.

This section describes:

1. The building blocks of modeling;
2. Inputs to BC Hydro’s System Optimizer program;
3. Methodology of analysis;
4. Integration of new resources; and
5. Process of selecting the required transmission upgrades.

5.1 Elements of Cluster Modeling

Basic components of cluster modeling are illustrated in Figure 13 using a hypothetical example. The figure is followed by a description of each component.

Figure 13  Elements of Cluster Modeling

5.1.1 Definition of Clusters

Assessment of transmission requirements for remote resources begins with modeling of areas of high-density generation resource potential that warrant consideration of interconnecting to the existing bulk transmission grid. These areas are referred to as clusters. A cluster is identified by its “Central Node”. This is defined to be a new substation in a reasonable proximity to all resources within the cluster. A central node is the collector hub for the power transmitted from resources within the cluster.

A cluster is often inclusive of different resource types such as small hydro, wind, and run-of-river. In this analysis, the following three guidelines delineate the boundaries of a cluster:

(i) A minimum of 500 MW total generation capacity;
(ii) A minimum of 0.06 MW/km² generation density;

(iii) At least 50 km distance from the existing bulk transmission grid.

Past studies and geographical characteristics of the resources are also considered in introducing clusters with lower requirements.

5.1.2 Definition of Bundles

Potential resources in large geographical areas such as the North Coast or Peace River are grouped together according to their similar characteristics and costs. Each group is called a resource bundle. For instance, all of the North Coast on-shore wind farms are grouped together to create a North Coast on-shore wind bundle. Generation plants within a bundle can be scattered along broad geographical boundaries. Therefore, it is possible to have a resource bundle with only a few of its plants inside a cluster.

5.1.3 T1 Transmission for Connecting Generation Plants

T1 is defined as the transmission circuit(s) which connects an individual resource plant to its nearest existing BC Hydro substation or line. In this IRP, T1 line voltages vary from 25 kV to 500 kV.

5.1.4 T2 Transmission for Connecting to a Cluster Node

T2 is defined as the transmission circuit(s) which connects an individual generation resource plant to its cluster’s central node. By definition, T2 circuits are not expected to be long. They include the same range of voltages as T1.

To model a cluster in BC Hydro’s System Optimizer program, T2 transmission interconnections between new cluster’s resource plants and its central node are defined. The main T2 characteristics are voltage, number of circuits and cost. The MW x km ranges, in the far right column of Table 1, are used as a reference guide for determining voltage level of T2 lines.
Table 1  Volatages of T2 Lines

<table>
<thead>
<tr>
<th>T2 Voltage Level (kV)</th>
<th>Capacity Range (MW)</th>
<th>Distance from Cluster's Central Substation (km)</th>
<th>75% of Distance x 75% of Capacity (MW x km)</th>
</tr>
</thead>
<tbody>
<tr>
<td>25</td>
<td>1</td>
<td>20</td>
<td>1</td>
</tr>
<tr>
<td>69</td>
<td>21</td>
<td>60</td>
<td>21</td>
</tr>
<tr>
<td>138</td>
<td>61</td>
<td>150</td>
<td>61</td>
</tr>
<tr>
<td>230</td>
<td>151</td>
<td>750</td>
<td>101</td>
</tr>
<tr>
<td>500</td>
<td>751</td>
<td>&gt;751</td>
<td>201</td>
</tr>
</tbody>
</table>

The above table indicates that T2 voltages are a function of both line capacity and circuit length. The 56 per cent\(^2\) reduction factor in the far right column is to avoid overrating of the lines.

Table 2 is a high level estimate of cost of building different transmission lines in B.C. This table is used for approximating the cost of T1, T2, and T3 circuits. T3 is defined as one or more high capacity transmission circuit(s) required for connecting a cluster’s central node to the nearest existing BC Hydro substation. The connection can be direct or via the central node of another cluster. In this IRP, for simplicity, only 500 kV and 230 kV circuits are considered for T3.

Table 2  Estimated Cost of Transmission Lines

<table>
<thead>
<tr>
<th>New Power Line Voltage (kV)</th>
<th>Cost ($/km), 2011 Dollars</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>Avg. Overhead Line Slope (0-15%)</td>
</tr>
<tr>
<td>-----------------------------</td>
<td>-------------------------------</td>
</tr>
<tr>
<td>25</td>
<td>84,800</td>
</tr>
<tr>
<td>69</td>
<td>106,000</td>
</tr>
<tr>
<td>138</td>
<td>159,000</td>
</tr>
<tr>
<td>230</td>
<td>265,000</td>
</tr>
<tr>
<td>500</td>
<td>530,000</td>
</tr>
</tbody>
</table>

\(^2\) 75 per cent x 75 per cent = 56.25 per cent.
5.2 Identifying Resource Clusters in B.C.

For this IRP transmission analysis, BC Hydro retained Kerr Wood Leidal Consulting Engineers (KWL) to review the data base of potential new generation resources, locate their GIS coordinates on a provincial map, and group the qualified ones into new resource clusters across the province.

Creation of the new clusters enables BC Hydro to assess their T2 and T3 transmission requirements. The transmission costs as well as line termination and voltage transformation costs are included in the comparison of clusters versus bundle portfolios in section 6.4.1. Other attributes such as environmental and economic impacts are also assessed. The comparison allows BC Hydro to quantify possible savings and identify risks associated with both cluster and bundle portfolio approaches.

The developed clusters for this IRP and the location of their respective central nodes are shown in Figure 14.
The above map is used for outlining major transmission corridors between the cluster nodes and the existing grid.

The identified T3 corridors constitute one element of BC Hydro’s long-term vision for expanding its transmission grid in the next 30 years. The other element is reinforcement of the existing bulk transmission network needed for accommodating the flow of power from the clusters and existing resources into the grid. High level assessment of both elements of the long-term transmission requirements is done using BC Hydro’s System Optimizer program. This section focuses on the cluster requirements. Bulk transmission reinforcements are addressed in section 6.

Identifying T3 transmission leads to the idea of expanding the bulk transmission network in advance of a certain need. This approach carries a risk of stranded transmission investment should the selected generation resources not materialize as expected. The risk concept is demonstrated in Figure 13 by assigning in-service
dates, which are after the in-service date of T3, to a number of future generation resources. If any one of these planned resources does not develop, the T3 line would become underutilized. Before making a final decision on building any new T3 circuit, a thorough risk/benefit analysis would need to be carried out.

5.2.1 Nodal Diagrams

A nodal diagram is a simplified representation of BC Hydro’s both existing / committed domestic transmission regions (zones) and new clusters.
Figure 15 shows the “Nodal Diagram” of the IRP analysis. It is an input to BC Hydro’s System Optimizer program and is used for determining transmission requirements. In this diagram each new cluster and each existing or committed bulk transmission region is represented by a node.

Also shown in the nodal diagram are nodes representing the U.S. and Alberta interties. These nodes do not contain any information about the transmission networks outside B.C. borders. They are included in the nodal diagram simply to signify B.C.’s transmission interties.
In the above diagram, solid lines connecting the nodes symbolize flow of power between two regions. These lines represent existing and committed transmission paths including BC Hydro’s interties to the U.S. and Alberta. The dashed lines represent interconnections between future cluster nodes and also between a cluster node and an existing BC Hydro transmission zone.

5.2.2 T3 Transmission for Connecting Clusters to the System

Once the System Optimizer program selects a new cluster of resources for a particular portfolio; it calculates the amount of power which flows from cluster’s central node towards the nearest existing transmission substation (or towards the
centre of nearest selected downstream cluster). The net flow from each node is equal to the cluster’s generation capacity\(^3\) minus cluster’s load. Where there is an upstream node, the upstream net flow minus upstream T3 transmission losses are added to the net flow from the cluster’s node.\(^4\) The node’s power flow level determines the voltage and number of T3 transmission circuits that each selected cluster requires.

In this IRP, it is assumed that the T3 voltages are limited to 500 kV and 230 kV HVAC.\(^5\) Table 3 shows how T3 transmission voltage and number of circuits are determined.

<table>
<thead>
<tr>
<th>T3 Power Line Segment</th>
<th>Flow Level for Selection of One 230kV (or 287kV) Circuit</th>
<th>Flow Level for Selection of One 500kV Circuit</th>
<th>Flow Level for Selection of Two 500kV Circuits</th>
</tr>
</thead>
<tbody>
<tr>
<td>LRD to FTN</td>
<td>Up to 235 MW</td>
<td>236 MW to 1200 MW</td>
<td>1200 MW to 2747 MW</td>
</tr>
<tr>
<td>FTN to NPR</td>
<td>See Note 1</td>
<td></td>
<td></td>
</tr>
<tr>
<td>NPR to PR</td>
<td>See Note 1</td>
<td></td>
<td></td>
</tr>
<tr>
<td>HCT to SKN</td>
<td>Up to 270 MW</td>
<td>271 MW to 1200 MW</td>
<td>1200 MW to 2984 MW</td>
</tr>
<tr>
<td>DLK to TGC</td>
<td>Up to 323 MW</td>
<td>324 MW to 1200 MW</td>
<td>1200 MW to 3329 MW</td>
</tr>
<tr>
<td>TGC to BQN</td>
<td>Up to 306 MW</td>
<td>307 MW to 1200 MW</td>
<td>1200 MW to 3220 MW</td>
</tr>
<tr>
<td>NVI to CBL</td>
<td>Up to 228 MW</td>
<td>229 MW to 1200 MW</td>
<td>1200 MW to 2702 MW</td>
</tr>
<tr>
<td>KTI to CBL</td>
<td>Up to 304 MW</td>
<td>305 MW to 1200 MW</td>
<td>1200 MW to 3202 MW</td>
</tr>
<tr>
<td>BU to CBL</td>
<td>Up to 308 MW</td>
<td>309 MW to 1200 MW</td>
<td>1200 MW to 3229 MW</td>
</tr>
<tr>
<td>CBL to DMR</td>
<td>Up to 382 MW</td>
<td>383 MW to 1200 MW</td>
<td>1200 MW to 3721 MW</td>
</tr>
</tbody>
</table>

Note 1: Selection of a transmission voltage level from Fort Nelson to Peace region (FTN to NPR plus NPR to PR) is provided from the BCTC’s 2009 Fort Nelson transmission study. This study assessed a range of transmission voltages including a double circuit 287 kV (rated 446 MW to 456 MW), one 230 kV circuit (rated 252 MW), and one 500 kV circuit (rated 633 MW to 656 MW).

\(^3\) Different generation levels corresponding to firm and non-firm dispatch of resources are defined in Appendix 4b “Integrated System Transmission Planning Assumptions”.

\(^4\) Transmission losses are addressed in section 5.2.3.

\(^5\) In this IRP transmission analysis, 287 kV and 230 kV circuits are assumed analogous and are represented by 230 kV. The only exception is the Fort Nelson to Peace region transmission (FTN-NPR-PR) where a double circuit 287 kV transmission is assessed.
The estimated direct capital costs of T3 lines are based on the KWL per kilometer cost of transmission lines. For the nodal diagram of Figure 15, the costs of T3 power lines are shown in Table 4. Where one or more of the above T3 lines are selected in a particular portfolio, their respective costs are added to the total cost of the analyzed portfolio.

<table>
<thead>
<tr>
<th>T3 Power Line Segment</th>
<th>Voltage (kV)</th>
<th>Number of Single Circuit Power Lines</th>
<th>Power Line Length (km)</th>
<th>Total (Not Including IDC, Rounded to Nearest $1000)</th>
<th>Approximate T3 Losses</th>
</tr>
</thead>
<tbody>
<tr>
<td>LRD to FTN</td>
<td>230</td>
<td>1</td>
<td>216</td>
<td>$102,789,000</td>
<td>2.90%</td>
</tr>
<tr>
<td>FTN to NPR</td>
<td>230</td>
<td>1</td>
<td>226</td>
<td>$114,063,000</td>
<td>3.03%</td>
</tr>
<tr>
<td>NPR to GMS</td>
<td>230</td>
<td>1</td>
<td>95</td>
<td>$47,743,000</td>
<td>1.27%</td>
</tr>
<tr>
<td>HCT to SKR</td>
<td>230</td>
<td>1</td>
<td>168</td>
<td>$140,460,000</td>
<td>2.25%</td>
</tr>
<tr>
<td>DLK to TGC</td>
<td>230</td>
<td>1</td>
<td>126</td>
<td>$59,478,000</td>
<td>1.69%</td>
</tr>
<tr>
<td>TGC to BQN</td>
<td>230</td>
<td>1</td>
<td>143</td>
<td>$76,350,000</td>
<td>1.92%</td>
</tr>
<tr>
<td>NVI to CBL</td>
<td>230</td>
<td>1</td>
<td>233</td>
<td>$115,186,000</td>
<td>3.13%</td>
</tr>
<tr>
<td>KTI to CBL</td>
<td>230</td>
<td>1</td>
<td>147</td>
<td>$99,718,000</td>
<td>1.89%</td>
</tr>
<tr>
<td>CBL to DMR</td>
<td>230</td>
<td>1</td>
<td>91</td>
<td>$40,613,000</td>
<td>1.22%</td>
</tr>
<tr>
<td>LRD to FTN</td>
<td>230</td>
<td>2</td>
<td>216</td>
<td>$205,578,000</td>
<td>1.45%</td>
</tr>
<tr>
<td>FTN to NPR</td>
<td>230</td>
<td>2</td>
<td>226</td>
<td>$228,126,000</td>
<td>1.52%</td>
</tr>
<tr>
<td>NPR to GMS</td>
<td>230</td>
<td>2</td>
<td>95</td>
<td>$95,486,000</td>
<td>0.63%</td>
</tr>
<tr>
<td>HCT to SKR</td>
<td>230</td>
<td>2</td>
<td>168</td>
<td>$280,919,000</td>
<td>1.13%</td>
</tr>
<tr>
<td>DLK to TGC</td>
<td>230</td>
<td>2</td>
<td>126</td>
<td>$118,957,000</td>
<td>0.85%</td>
</tr>
<tr>
<td>TGC to BQN</td>
<td>230</td>
<td>2</td>
<td>143</td>
<td>$152,700,000</td>
<td>0.96%</td>
</tr>
<tr>
<td>NVI to CBL</td>
<td>230</td>
<td>2</td>
<td>233</td>
<td>$230,371,000</td>
<td>1.57%</td>
</tr>
<tr>
<td>KTI to CBL</td>
<td>230</td>
<td>2</td>
<td>147</td>
<td>$232,553,000</td>
<td>0.99%</td>
</tr>
<tr>
<td>CBL to DMR</td>
<td>230</td>
<td>2</td>
<td>91</td>
<td>$199,436,000</td>
<td>0.95%</td>
</tr>
<tr>
<td>LRD to FTN</td>
<td>500</td>
<td>1</td>
<td>216</td>
<td>$195,963,000</td>
<td>1.73%</td>
</tr>
<tr>
<td>FTN to NPR</td>
<td>500</td>
<td>1</td>
<td>226</td>
<td>$228,126,000</td>
<td>1.52%</td>
</tr>
<tr>
<td>NPR to GMS</td>
<td>500</td>
<td>1</td>
<td>95</td>
<td>$62,898,000</td>
<td>0.76%</td>
</tr>
<tr>
<td>HCT to SKR</td>
<td>500</td>
<td>1</td>
<td>168</td>
<td>$217,703,000</td>
<td>1.35%</td>
</tr>
<tr>
<td>DLK to TGC</td>
<td>500</td>
<td>1</td>
<td>126</td>
<td>$115,399,000</td>
<td>1.01%</td>
</tr>
<tr>
<td>TGC to BQN</td>
<td>500</td>
<td>1</td>
<td>143</td>
<td>$142,449,000</td>
<td>1.15%</td>
</tr>
<tr>
<td>NVI to CBL</td>
<td>500</td>
<td>1</td>
<td>233</td>
<td>$216,250,000</td>
<td>1.87%</td>
</tr>
<tr>
<td>KTI to CBL</td>
<td>500</td>
<td>1</td>
<td>147</td>
<td>$232,553,000</td>
<td>0.99%</td>
</tr>
<tr>
<td>BUI to CBL</td>
<td>500</td>
<td>1</td>
<td>141</td>
<td>$199,436,000</td>
<td>0.95%</td>
</tr>
<tr>
<td>CBL to DMR</td>
<td>500</td>
<td>1</td>
<td>91</td>
<td>$80,608,000</td>
<td>0.73%</td>
</tr>
<tr>
<td>LRD to FTN</td>
<td>500</td>
<td>2</td>
<td>216</td>
<td>$391,926,000</td>
<td>0.87%</td>
</tr>
<tr>
<td>FTN to NPR</td>
<td>500</td>
<td>2</td>
<td>226</td>
<td>$300,540,000</td>
<td>0.91%</td>
</tr>
<tr>
<td>NPR to GMS</td>
<td>500</td>
<td>2</td>
<td>95</td>
<td>$125,796,000</td>
<td>0.38%</td>
</tr>
<tr>
<td>HCT to SKR</td>
<td>500</td>
<td>2</td>
<td>168</td>
<td>$435,407,000</td>
<td>0.67%</td>
</tr>
<tr>
<td>DLK to TGC</td>
<td>500</td>
<td>2</td>
<td>126</td>
<td>$230,798,000</td>
<td>0.51%</td>
</tr>
<tr>
<td>TGC to BQN</td>
<td>500</td>
<td>2</td>
<td>143</td>
<td>$284,898,000</td>
<td>0.57%</td>
</tr>
<tr>
<td>NVI to CBL</td>
<td>500</td>
<td>2</td>
<td>233</td>
<td>$432,500,000</td>
<td>0.94%</td>
</tr>
<tr>
<td>KTI to CBL</td>
<td>500</td>
<td>2</td>
<td>147</td>
<td>$407,045,000</td>
<td>0.59%</td>
</tr>
<tr>
<td>BUI to CBL</td>
<td>500</td>
<td>2</td>
<td>141</td>
<td>$399,307,000</td>
<td>0.57%</td>
</tr>
<tr>
<td>CBL to DMR</td>
<td>500</td>
<td>2</td>
<td>91</td>
<td>$161,217,000</td>
<td>0.36%</td>
</tr>
<tr>
<td>FTN to NPR</td>
<td>287</td>
<td>Double</td>
<td>226</td>
<td>$133,705,000</td>
<td>1.52%</td>
</tr>
<tr>
<td>NPR to GMS</td>
<td>287</td>
<td>Double</td>
<td>95</td>
<td>$55,964,000</td>
<td>0.63%</td>
</tr>
</tbody>
</table>

6 Transmission cost estimates for FTN to NPR and NPR to PR are based on the BCTC’s 2009 Fort Nelson transmission study. The final IRP will update this analysis with more current cost estimates although the results are not expected to materially change.

7 In Table 3, the VI node is represented by two substations: Campbell River (CBL) in northern VI and Dunsmuir (DMR) in central VI.
The cost of a transmission circuit is not limited to the cost of T3 circuits. Other T3 capital costs, which are added to each portfolio’s cost, are approximated to be:

- Cost of a new cluster’s central substation: $70.0 million;
- Cost of terminating each 500 kV T3 line into an existing substation: $7.8 million;
- Cost of terminating each 230 kV T3 line into an existing substation: $3.8 million;
- Cost of 230 kV to 500 kV transformation at an existing substation: $0.043 million per MW.

The above are high-level estimates of the expected expenditure based on the cost of similar upgrades in BC Hydro’s network.

5.2.3 Transmission Losses in IRP Analysis

Modeling of transmission losses is to assess the portion of generated electricity which is dissipated as heat and therefore not available to serve the electrical load. In this IRP analysis, network transmission losses, which are input to the BC Hydro’s System Optimizer program, are divided into three types:

- Interconnection losses;
- Losses of the existing bulk transmission network; and
- Other network losses.

The interconnection losses associated with the T3 circuits are shown in Table 4. These losses are defined as approximate percentage of the power flow on each circuit.

The second group of losses is related to the flow of power on the existing bulk transmission paths. In this IRP study, a high level estimate of the existing bulk transmission’s average losses are included in the cut-plane flow calculations.
The last group of network losses is consists of conductor losses for the sub-transmission and distribution\(^8\) circuits as well as core and iron losses associated with the substation transformers. To account for this category of losses, the regional loads are augmented by 1.2 per cent.

6 Bulk System Transmission Analysis

This section presents the analysis, results and conclusions of the transmission modeling work performed to support the IRP. It presents a view as to how the transmission network might evolve over the next 20 to 30 years.

Due to the lengthy lead times in planning, permitting and constructing transmission facilities, BC Hydro has always had to identify transmission requirements at least 10 years into the future. In the 2008 Long Term Acquisition Plan (LTAP), BC Hydro studied 18 portfolios and their transmission requirements over a twenty year timeframe. In accordance with the CEA and as part of this IRP, BC Hydro has studied transmission requirements for various portfolios over a period of 20 to 30 years. Analysis of the long-term transmission requirements has been conducted by adhering to BC Hydro’s “Technical Assumptions for Integrated Power System Planning.”\(^9\)

The IRP transmission analysis identifies where and when incremental transmission capacity will be required for a particular load / resource portfolio. In this context, the specified transmission additions represent typical solutions for two distinct applications:

(a) “Transmission Options” for removing congestion from an existing transmission path by adding incremental transfer capacity to the constrained path;

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\(^8\) In this loss analysis, sub-transmission is referred to 360 kV, 230 kV, 287 kV, 138 kV, and 69 kV regional circuits. Distribution circuits include 25 kV and 12 kV feeders.

\(^9\) See Appendix 2D.
(b) “T3” lines for integrating clusters of new resources into the existing transmission grid.

The IRP transmission analysis is not meant to compare possible transmission alternatives and to recommend optimum transmission solutions. Furthermore, the analysis does not imply that the scope and estimated cost of the presented solutions are final. Instead, it is a process which highlights areas of high-density generation resource potential that warrant consideration of upgrades to the existing bulk transmission grid.

### 6.1 IRP Transmission Planning Criteria

The “Technical Assumptions for Integrated Power System Planning” document, also known as the IRP Planning Criteria, defines BC Hydro’s guidelines for planning a reliable transmission network which is adequate for dispatching designated generation resources to serve the forecasted demand. The document was initially published as Appendix F9 of the 2008 LTAP Application. For system performance under normal and emergency conditions, the criteria conform to the BCUC approved Mandatory Reliability Standards for transmission planning. The IRP Planning Criteria expands the original document to include the latest BC Hydro planning practices and to elaborate on topics such as:

- Transmission planning for dispatch of maximum resource capacities under normal conditions;
- Transmission planning for dispatch of dependable generation capacities of resources under single contingency conditions; and
- Load forecast and Demand Side Measures (DSM) assumptions.

The IRP Planning Criteria are included in Appendix 2D.

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10 The NERC Transmission Planning standards TPL-001, TPL-002, TPL-003, and TPL-004 are a part of the NERC reliability standards which are mandatory in B.C. The latest version of these standards can be found on the BCUC website.
6.2 Transmission Options for the Existing Network

The requirement for ensuring the bulk transmission system remains within its thermal and stability limits under all demand conditions is established by the BCUC approved NERC Reliability Standard. BC Hydro’s planning practice is to comply with the NERC requirements for all seasonal load variations and generation dispatch patterns. This is done by examining flows on the bulk transmission network which is outlined in section 3.

Once the expected flow on a transmission cut-plane exceeds its lowest rating, the cut-plane’s total transfer capability (TTC) has to be increased. The incremental capacity should be sufficient to allow reliable flow of the expected power without causing any transmission congestion.

In the past, BC Hydro has studied some of the possible “Transmission Options” (TOs) which can provide different levels of incremental capacity to its bulk transmission cut-planes. Details of BC Hydro’s bulk transmission options for different transmission regions and their respective incremental capacities are discussed in section 3.

TOs are one of the inputs into the BC Hydro’s System Optimizer tool. Should power flow on a particular cut-plane exceed its capacity and cause congestion, the tool selects the applicable transmission option for removing the constraint. The results of the System Optimizer are adjusted to ensure that the selected transmission options provide adequate capacity for the full dispatch of all selected resources which could flow on the cut-plane. In the IRP process, costs of the added transmission options are included in the overall cost of each analyzed portfolio.

A summary of the bulk transmission options, their expected incremental capacities, and their estimated costs are shown in Table 5. In this table, projects with specific in-service dates are undergoing different stages of approval. In this IRP, such projects are considered committed. A committed project is selected in all System Optimizer’s simulations.
## Table 5: Bulk Transmission Options for the IRP

<table>
<thead>
<tr>
<th>Item No.</th>
<th>Upgrade Option Description</th>
<th>Lead Time (Years)</th>
<th>2011 Direct Cost ($Million)</th>
<th>Incremental Capacity (MW)</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>North Interior</strong></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>TO-01</td>
<td>New 500 kV, 50% series compensated transmission circuit 5L8 between GMS and Williston</td>
<td>8</td>
<td>$373.2</td>
<td>1470</td>
</tr>
<tr>
<td>TO-02</td>
<td>New 500 kV, 50% series compensated transmission circuit 5L14 between Williston and Kelly Lake</td>
<td>8</td>
<td>$327.9</td>
<td>2120</td>
</tr>
<tr>
<td>TO-03</td>
<td>New +/-500 kV HVDC bipole transmission circuit between Peace River and Lower Mainland - Phase 1</td>
<td>8</td>
<td>$1,425.3</td>
<td>1000</td>
</tr>
<tr>
<td>TO-04</td>
<td>New +/-500 kV HVDC bipole transmission circuit between Peace River and Lower Mainland - Phase 2</td>
<td>8</td>
<td>$237.2</td>
<td>1000</td>
</tr>
<tr>
<td>TO-05</td>
<td>Series compensation upgrade at Kennedy from 50% to 65% on GMS to Williston 500 kV lines 5L1, 5L2, 5L3 and 5L7 with thermal upgrades to 3000A rating.</td>
<td>3</td>
<td>$57.2</td>
<td>360 (CH-KLY/NIC) and 300 (PR-CI)</td>
</tr>
<tr>
<td>TO-06</td>
<td>Series compensation upgrade at McLeese from 50% to 65% on Williston to Kelly 500 kV lines 5L11, 5L12 and 5L13 with thermal upgrades to 3000A rating.</td>
<td>3</td>
<td>$55.0</td>
<td>390 (CH-KLY/NIC) and 330 (PR-CI)</td>
</tr>
<tr>
<td>TO-07</td>
<td>500 kV Shunt compensation: At Williston, add one 300 MVar SVC and two 250 MVar switchable capacitor banks. At Kelly Lake, add one 250 MVar shunt capacitor.</td>
<td>3</td>
<td>$62.6</td>
<td>650 (CH-KLY/NIC) and 580 (PR-CI)</td>
</tr>
<tr>
<td><strong>South Interior</strong></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>TO-08</td>
<td>New 500 kV circuit Williston-Glenannan-Telkwa-Skeena parallel to the existing SL61 - SL62 and SL63 lines.</td>
<td>8</td>
<td>$991.5</td>
<td>970</td>
</tr>
<tr>
<td>TO-09</td>
<td>50% series compensation of the WSN-CLN 500 kV line SL63 (or SL61 or SL62)</td>
<td>3</td>
<td>$31.8</td>
<td>580</td>
</tr>
<tr>
<td>TO-10</td>
<td>A new 449 km long +/-500 kV HVDC bipole transmission circuit between WSN and SKA.</td>
<td>8</td>
<td>$1,049.2</td>
<td>2000</td>
</tr>
<tr>
<td><strong>Interior to Lower Mainland</strong></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>TO-11</td>
<td>New 500 kV, 50% series compensated transmission circuit 5L97 between Selkirk and Vaseaux Lake</td>
<td>8</td>
<td>$217.9</td>
<td>750</td>
</tr>
<tr>
<td>TO-12</td>
<td>50% series compensation of the 500 kV lines 5L91 and 5L98.</td>
<td>3</td>
<td>$59.4</td>
<td>133 (SEL-KLY/NIC) and 147 (SEL-REV/ACK)</td>
</tr>
<tr>
<td>TO-13</td>
<td>50% series compensation of 500 kV lines 5L71 and 5L72.</td>
<td>Committed in 2014</td>
<td>$44.2</td>
<td>950</td>
</tr>
<tr>
<td>TO-14</td>
<td>50% series compensation of 500 kV lines 5L76, 5L79, and 5L96.</td>
<td>3</td>
<td>$58.0</td>
<td>112</td>
</tr>
<tr>
<td>TO-15</td>
<td>50% Series compensation of 500 kV line 5L92 SEL-CBK.</td>
<td>3</td>
<td>$30.0</td>
<td>150</td>
</tr>
<tr>
<td>TO-16</td>
<td>A new 500 kV line between SEL and CBK. To define this line, information from Section 5 Inquiry for a new 500 kV line from SEL to Alberta border (287 km, TTC + 1550 MW) is utilized. The new CBK - SEL 500 kV line will be 180 km long.</td>
<td>8</td>
<td>$625.8</td>
<td>1550</td>
</tr>
<tr>
<td><strong>Lower Mainland to Vancouver Island</strong></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>TO-17</td>
<td>New 230 kV transmission circuit 2L124 between Arnott and Vancouver Island terminal.</td>
<td>6</td>
<td>$221.2</td>
<td>600</td>
</tr>
</tbody>
</table>

**Note:** Costs are in 2011 dollars.
6.3 20-Year Bulk System Analysis and Requirements

There are numerous combinations of different resource options that could be used to fill the gap between future anticipated demand and current supply. These combinations are described as “portfolios”. Each portfolio has an associated set of “Transmission Options”. 

In the following sub-sections, transmission requirements of portfolios with 20-year time horizon (ending in 2030) are evaluated.

6.3.1 Transmission Requirements: Demand / Resource Gap Size

A range of portfolios for high, medium, and low demand/resource gap sizes are analyzed. Generally, new 500 kV transmission circuits on GMS-WSN corridor are suggested only after the incremental transmission capacity provided by reactive compensation additions along this corridor is fully exhausted.

Table 6 summarises transmission requirement results of the analysis for the reviewed portfolios:

<table>
<thead>
<tr>
<th>No.</th>
<th>Conclusion</th>
</tr>
</thead>
<tbody>
<tr>
<td>1</td>
<td>None of the analyzed “Low Gap” portfolios result in adding a new transmission line to the existing BC Hydro bulk transmission grid. Non-wire transmission solutions including series and shunt compensation of the existing circuits will be required.</td>
</tr>
<tr>
<td>2</td>
<td>Majority of the analyzed “Medium Gap” portfolios do not result in adding a new transmission line to the existing BC Hydro bulk transmission grid. Non-wire transmission solutions including series and shunt compensation of the existing circuits will be required.</td>
</tr>
<tr>
<td>3</td>
<td>“Medium Gap” portfolios which include the North Coast LNG3 load can result in building the new 500 kV circuit 5L8 along the GMS-WSN corridor. The new line can be required as early as 2020.</td>
</tr>
<tr>
<td>4</td>
<td>“High Gap” scenarios result in building new 500 kV circuits 5L8 and/or 5L14 along the GMS-WSN-KLY corridor. The new lines are often required towards the end of the 20 year planning horizon between 2027 and 2030. Prior to the line addition, this corridor has to be reinforced with non-wire options.</td>
</tr>
</tbody>
</table>
6.3.2 Transmission Requirements: DSM Options

DSM Options 1 to 5 with low, medium, and high levels of achievement are examined for all three gap sizes. The analysis includes market scenarios B and C. Review of the analysis results verifies the conclusions of Table 7 in section 6.3.1. Generally, higher levels of DSM achievement are expected to delay the in-service date of required transmission solutions.

6.3.3 Transmission Requirements: Supply of North Coast Loads

The base IRP portfolio included 550 MW of the initial LNG load in the North Coast near Kitimat. To supply this load by clean energy from the system, the North Coast 500 kV path must be reinforced. Analyzed portfolios indicate that series compensation of 500 kV lines 5L61 (WSN-GLN), 5L62 (GLN-TKW), and 5L63 (TKW-SKA) plus shunt compensation in TKW and SKA regional transmission networks will allow up to 1,380 MW of North Coast load to be served from WSN. This level of capacity is adequate for all portfolios with the initial LNG and other North Coast regional loads other than the LNG3 load.

The addition of up to 1,200 MW of LNG3 load to the North Coast region is also investigated. Should all the new LNG and Bob Quinn loads be served from WSN using system’s clean resources, a new series compensated WSN-GLN-TKW-SKA 500 kV circuit will be required. Other necessary North Coast transmission additions include building a new 500 kV substation around Kitimat area to supply the LNG loads by two new 500 kV lines from SKA to the new substation. These additions are expected to increase the load serving capability of the North Coast region to approximately 2,350 MW.

In this IRP, the impact of adding new North Coast loads on the bulk transmission grid north and south of Williston Substation are also examined. All reviewed portfolios include the initial LNG load. Sensitivity cases including LNG3 load and other North Coast loads along the Northwest Transmission line, Rupert, and Kitimat...
areas are completed. The results of the analysis for the transmission requirements are shown in Table 7:

**Table 7** Transmission Requirements Based on the North Coast Loads

<table>
<thead>
<tr>
<th>No.</th>
<th>Conclusion</th>
</tr>
</thead>
<tbody>
<tr>
<td>1</td>
<td>All portfolios with only the initial LNG load and supply of clean energy from WSN require shunt and series compensation of the WSN-GLN-TKW-SKA 500 kV circuit.</td>
</tr>
<tr>
<td>2</td>
<td>With only the initial LNG load, all of the “Low Gap” and majority of the “Medium Gap” portfolios do not result in adding a new transmission line to the existing BC Hydro bulk transmission grid. Non-wire transmission solutions including series and shunt compensation of the existing circuits will be required.</td>
</tr>
<tr>
<td>3</td>
<td>All portfolios with only the initial LNG load and “High Gap” result in building new 500 kV circuits 5L8 and/or 5L14 along the GMS-WSN-KLY corridor. The new lines are often required towards the end of the 20-year planning horizon between 2027 and 2030. Prior to the line addition, this corridor has to be reinforced with non-wire options.</td>
</tr>
<tr>
<td>4</td>
<td>For supply of North Coast loads by clean resources from WSN side, inclusion of LNG3 load causes building the new 500 kV circuit 5L8 along the GMS-WSN corridor. The new line can be required as early as 2020.</td>
</tr>
<tr>
<td>5</td>
<td>Portfolios which are based on supply of both the initial LNG and LNG3 loads by clean resources from WSN side lead to the second series compensated WSN-GLN-TKW-SKA 500 kV circuit.</td>
</tr>
<tr>
<td>6</td>
<td>Many of the portfolios with both the initial LNG and LNG3 loads show that the need for a second WSN-GLN-TKW-SKA 500 kV line can be eliminated should the aggregate North Coast load, that has to be served from WSN, remain below 1,380 MW. Often, this can be achieved by adding thermal resources in the North Coast region to supply the local loads.</td>
</tr>
<tr>
<td>7</td>
<td>Inclusion of thermal resources in KLY instead of NC does not eliminate the need for a new WSN-GLN-TKW-SKA 500 kV circuit.</td>
</tr>
</tbody>
</table>

**6.3.4 Transmission Requirements: Revelstoke Unit 6**

Addition of the sixth Revelstoke unit will trigger series compensation of the South Interior 500 kV transmission lines. Previous technical studies have tied the number of compensated circuits to the timing of Revelstoke Unit 6. In the IRP analysis, Revelstoke Unit 6 will be in-service after Waneta Expansion project. This sequence will require series compensation of 5L91 and 5L98.
6.3.5 Transmission Requirements: ILM

The reviewed portfolios indicate that, after building 5L83 in 2015, no other new ILM line will be required in the 20-year planning horizon. The absence of a new ILM line is mainly attributed to the proposed installation of large pumped storage facilities in the Lower Mainland. The feasibility and timing of these facilities is uncertain and requires further study.

In the absence of pumped storage units, additional transmission capacity between the Interior and Lower Mainland will be required. In such cases, the first stage of ILM development is full utilization of the existing network capacity by adding adequate reactive power support. This can be followed by building a second series compensated 500 kV line between KLY and CKY (5L46). Another possible solution is the installation of new generation resources in the LM and VI to the extent that their dependable capacity offsets the required incremental ILM capacity.

The IRP analysis indicates that for medium demand/resource gaps, replacing the LM pumped storage facilities with SCGT peaking units at KLY will result in building a new series compensated 500 kV line between KLY and CKY (5L46) in 2029. The same new line will be needed in 2023 if the demand/resource gap is high.

6.4 30-Year Bulk System Analysis and Requirements

The CEA requires BC Hydro to submit to the provincial government a description of the BC Hydro’s infrastructure and capacity needs for electricity transmission for the period ending 30 years after the date the IRP is submitted. To comply with this requirement, two 30-year load/resource portfolios (ending in 2040) are evaluated.

The 30-year portfolios are to compare the cluster and bundle approaches. These methods of analysis are described in sections 5.1.1 and 5.1.2 respectively. The analysis is intended to highlight advantages and disadvantages of cluster approach and building cluster transmission ahead of need.
6.4.1 Comparison of 30-Year Clusters and Bundles

The IRP 30-year portfolio analysis provides the evidence required to determine whether pre-building new transmission lines is beneficial. The competing alternative is allowing individual resources to interconnect directly to the grid as they develop in the future.

In this section, the base 30-year portfolio is examined using both cluster and bundle representations of future resources. The selected base case clusters include: Bute Inlet in 2017, Knight Inlet in 2020, and NPR in 2033. The present value (PV) of generation and transmission costs and trade revenues for both options are calculated in 2011 dollars. These PVs are summed to determine the total portfolio cost for each option. The results of the analysis are shown in Table 8.

<table>
<thead>
<tr>
<th>Measure</th>
<th>Results</th>
<th>Bundle</th>
<th>Cluster</th>
</tr>
</thead>
<tbody>
<tr>
<td>Generation &amp; Transmission Resource Cost</td>
<td>$ Million PV</td>
<td>12,250</td>
<td>11,941</td>
</tr>
<tr>
<td>Trade Revenue</td>
<td>$ Million PV</td>
<td>-1,215</td>
<td>-1,190</td>
</tr>
<tr>
<td>DSM Option Cost</td>
<td>$ Million PV</td>
<td>3,996</td>
<td>3,996</td>
</tr>
<tr>
<td>Total Portfolio Cost</td>
<td>$ Million PV</td>
<td>15,031</td>
<td>14,747</td>
</tr>
</tbody>
</table>

It is recognized that financial parameters are not the sole measure for comparing the cluster and bundle models. Other contributing factors, which are assessed in this document, include environmental and economic development implications of each approach. These footprints for cluster and bundle portfolios are summarized in Table 9 and Table 10 respectively.

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11 For location of new clusters see sections 5.2 and 5.2.1.
Table 9  Environmental Implications of Cluster & Bundle Cases

<table>
<thead>
<tr>
<th></th>
<th>Measure</th>
<th>Bundle</th>
<th>Cluster</th>
</tr>
</thead>
<tbody>
<tr>
<td>Land</td>
<td>Total hectares</td>
<td>25,100</td>
<td>23,000</td>
</tr>
<tr>
<td>Affected Stream Length</td>
<td>km</td>
<td>390</td>
<td>450</td>
</tr>
<tr>
<td>Marine (valued ecological features)</td>
<td>Total hectares</td>
<td>150</td>
<td>100</td>
</tr>
</tbody>
</table>

Table 10  Economic Development Implications of Clusters and Bundle Cases

<table>
<thead>
<tr>
<th></th>
<th>Measure</th>
<th>Bundle</th>
<th>Cluster</th>
</tr>
</thead>
<tbody>
<tr>
<td>Total GDP</td>
<td>$ Million PV</td>
<td>13,900</td>
<td>14,600</td>
</tr>
<tr>
<td>Employment</td>
<td>Total FTEs</td>
<td>350,500</td>
<td>363,200</td>
</tr>
<tr>
<td>Government Revenue</td>
<td>$ Million PV</td>
<td>2,200</td>
<td>2,300</td>
</tr>
</tbody>
</table>

Inspection of the analyzed portfolios and their respective costs and footprints leads to the following conclusions:

(i) The cluster approach is less costly than the bundle approach;

(ii) The difference in PV of costs is mainly attributed to the fewer number of required transmission lines in the cluster approach;

(iii) The total savings associated with the cluster approach is less than 2 per cent of the total portfolio cost. This expected cost saving is within the accuracy range of the analysis;

(iv) Building new transmission lines for integration of future generation clusters is expected to reduce the overall impact on the environment. This is mainly because clusters have fewer transmission lines than bundles;

(v) The cluster approach is expected to create more government revenue and local employment than the bundle approach. The overall difference is less than 5 per cent of the total revenue and is considered within the accuracy range of the analysis;
(vi) Building transmission now for integration of future clusters includes uncertainties. Should the future resources do not materialize, BC Hydro will remain with stranded or under-utilized transmission assets;

(vii) Securing a new transmission corridor towards a selected region of the province creates the perception of bias towards development of that region at the expense of other non-selected regions.

7 Transmission Recommendations

BC Hydro examined both “bulk transmission infrastructure” and “remote resource integration” requirements to meet 20- and 30-year forecasts of electricity demand in B.C. The review included both expected and contingency conditions and focused on the potential for electrification load and North Coast LNG load growth opportunities.

In addition, BC Hydro gave consideration to pre-building or reinforcing new transmission in areas with high clean generation potential (clusters). The challenge for BC Hydro, as it undertook this assessment, was whether and to what extent should it take a proactive approach to advancing transmission infrastructure to minimize both costs and the number of transmission additions that would need to be built in the many regions of the province.

Inspection of the identified resource clusters indicated that for many remote generation regions there are financial and environmental advantages in promoting transmission in advance of the need. Additionally, proactive advancement of transmission infrastructure could resolve the long lead time requirements of the new transmission circuits. However, the uncertainties associated with the export market, electrification, and future calls for power were significant. These uncertainties together with the error margin of studies could avoid the new clusters from being materialized.
Advancing transmission in face of such uncertainties carries a risk of stranded or under-utilized transmission investment. In making the recommendations, both benefits and risks of building transmission ahead of need are considered.12

7.1.1 Recommended Actions:

(i) BC Hydro should continue with previously identified non-wire upgrades to the existing transmission lines and substations on the G.M. Shrum to Williston to Kelly Lake 500 kV transmission system. These upgrades will maximize the transfer capability of existing assets and do not require new ROWs.

(ii) BC Hydro should proceed with the planning, preliminary design and consultation activities to prepare for the option of a new transmission line from Peace region to Williston. The need for this new line depends on the outcome of supply options for additional LNG loads on the North Coast and could be as early as 2019 should the preferred option be to supply these loads from the grid. In the absence of additional LNG loads on the North Coast, this new line will only be needed for high demand/resource gap size portfolios and only after 2027.

(iii) BC Hydro should proceed with the planning, design, and approvals necessary to reinforce the existing Williston to Skeena 500 kV transmission system by installing adequate shunt support and series compensation of the 500 kV lines 5L61, 5L62, and 5L63. These are required to serve the LNG loads on the North Coast that are identified in the base resource plan and while no new transmission ROW is required, new sites for the three series capacitor stations may be necessary. Should the initial North Coast LNG load not proceed on the expected time lines, the need for reactive power compensation of the North Coast transmission system has to be re-evaluated.

(iv) BC Hydro should proceed with the planning, preliminary design, and consultation necessary to prepare for the option of building a new 500 kV AC

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12 Refer to section 6.3.1.
circuit from Williston to Glenannan to Telkwa to Skeena. The need for this line will depend on the outcome of supply options for the additional LNG3 loads on the North Coast and could be as early as 2019 should the preferred option be to supply these loads from the grid.

(v) BC Hydro should proceed with investigating the feasibility of pumped storage facilities in the Lower Mainland. These resources form a significant portion of the generation capacity additions in the base plan starting in 2021 and have the additional benefit of deferring any new investments on Williston to Kelly Lake and Interior to Lower Mainland transmission lines.

(vi) BC Hydro should further evaluate building adequate transmission to the identified high potential generation cluster regions during future acquisition processes if and when projects in these regions are proposed.

7.1.2 Justification:

7.1.2.1 North Coast Upgrades

BC Hydro investigated the electrification of LNG and mining loads in the North Coast region and along the NTL corridor. It focused on the bulk transmission reinforcements which allow serving the incremental North Coast loads using clean energy flowing from Central Interior.

It was observed that the approximately 800 MW post-NTL load serving capability of the North Coast region is not sufficient for serving Kitimat LNG and other mining loads in the region. Series compensation of the three North Coast 500 kV lines 5L61, 5L62, and 5L63 plus addition of shunt reactive power along this path can provide approximately 580 MW incremental load serving capability in the North Coast region.

There should be provisions for series compensation of a second WSN-GLN-TKW-SKA 500 kV circuit. This will be a relatively short duration project and each capacitor station can be delivered within three years.
Should the anticipated initial LNG and mining loads not materialize or should the market participants decide against supplying their loads by clean energy from BC Hydro’s network, the upgrades will become stranded investments.

Any investment on a second 500 kV WSN-GLN-TKW-SKA circuit is tied to the future of North Coast LNG loads. Should the LNG3 load materialize and BC Hydro decide to supply it by clean energy resources from the system side, this new line will be required as early as 2019. Considering the long lead time for a new 500 kV circuit, it is justifiable to initiate the planning and approval phases of the project and secure the required RoW.

7.1.2.2 Peace System Upgrades

Addition of Site C and supply of North Coast load by clean system resources leads to increased flows on the GMS-WSN transmission path. Consequently, additional transfer capacity on this path will be required.

To the extent that increased North Coast demand is limited to Kitimat LNG load, the additional capacity requirements can be provided by adding shunt compensation and enhancing series compensation of the existing GMS to WSN path. These are relatively short duration projects without any need for new RoW or new substation land.

More aggressive LNG3 load addition in the North Coast surpasses the transfer capacity of the reinforced GMS-WSN transmission path. A new 500 kV circuit from Peace region to Williston Substation would provide the required incremental capacity.

Any investment on a new 500 kV circuit from Peace River area to Williston Substation is tied to the future of North Coast LNG loads. Should the LNG3 load materialize and BC Hydro decide to supply it by clean energy resources from the system side, this new line will be required as early as 2020. Considering the long
lead time for a new 500 kV circuit, it is justifiable to initiate the planning and approval phases of the project and secure the required RoW.

7.1.2.3 Transmission Circuits for Future Clusters

The IRP analysis showed that, for the high potential generation clusters, there is modest financial benefit associated with developing clusters to meet customer demand. It also shows there is potential to reduce environmental impacts as a result of optimal transmission configurations. Also, there are limited economic development benefits. Meanwhile, there are also significant risks associated with advancing transmission for clusters, that include:

- Stranded transmission investment if the expected generation projects do not materialize;
- Negative impacts on call bidding behaviour, which could erode any financial benefit to pre-building;
- A perception of bias towards the regions which will benefit from building advance transmission; and
- Margins of error in the analysis supporting the advancement of transmission as a result of having less than perfect information regarding the quality and quantity of clean or renewable resources in the areas under study.

Accordingly, BC Hydro recommends that additional transmission cluster considerations be undertaken during acquisition processes when it becomes more certain that projects in a particular region are being developed and the benefits of optimizing transmission build are more likely to be realized.