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July 9, 2020

British Columbia Public Interest Advocacy Centre
Suite 803 470 Granville Street
Vancouver, B.C.
V6C 1V5

Attention: Ms. Leigha Worth, Executive Director

Dear Ms. Worth:

Re: FortisBC Inc. (FBC)

Project No. 1599088

Application for a Certificate of Public Convenience and Necessity for the Kelowna Bulk Transformer Addition Project (the Application)

Response to the British Columbia Public Interest Advocacy Centre representing the British Columbia Old Age Pensioners' Organization, Council of Senior Citizens' Organizations of BC, Active Support Against Poverty, Disability Alliance BC, and the Tenant Resource and Advisory Centre (BCOAPO) Information Request (IR) No. 1

On April 24, 2020, FBC filed the Application referenced above. In accordance with the British Columbia Utilities Commission Order G-107-20 setting out the Regulatory Timetable for the review of the Application, FBC respectfully submits the attached response to BCOAPO IR No. 1.

If further information is required, please contact the undersigned.

Sincerely,

FORTISBC INC.

Original signed:

Doug Slater

Attachments

cc (email only): Commission Secretary
Registered Parties

1.0 Reference: Exhibit B-1, pages 4 and 57

Preamble: At page 4 the Application states:

"Prior to filing the Application, FBC sent notification letters to area residents and stakeholders who have the potential to be directly affected by the Project. Various channels were used to reach customers including letters, updates on the Project website3, and a Project survey. FBC has also notified local government authorities and responded to requests for further information".

At page 57 the Application states:

"The Key Stakeholders for the KBTA Project have been identified as:

- City of Kelowna elected officials and staff;
- Residents and businesses at the Tower Ranch subdivision and Tower Ranch Golf & Country Club, and other residents adjacent to or in close proximity to LEE; and
- Indigenous Communities as identified through the Provincial Consultative Areas Database."

1.1 Are "key stakeholders" and "those directly affected by the Project" the same? If not, what is the difference?

Response:

Key stakeholders is a term broadly applied to cover all parties that may be impacted directly by a project, such as area residents and businesses in close proximity to a project site, as well as parties that may be indirectly impacted, such as those with jurisdictional interests, such as a municipality or First Nation. Therefore, "those directly affected by the Project" is a subset of key stakeholders.

To determine area residents and businesses that would potentially be directly affected by the Project, FBC referred to property mapping and billing information for residents and businesses in closest proximity and adjacent to the Project location.

While not directly affected by the Project, FBC identified City of Kelowna elected officials and staff as key stakeholders to ensure they were made aware of the Project since it is being constructed within City limits. FBC obtained a list of Indigenous communities with interests in the area of the Project through the Provincial Consultative Areas Database.

1.2 Please explain how FBC determined which area residents and stakeholders would be "directly affected" by the Project.

Response:

Please refer to the response to BCOAPO IR1 1.1.

1.3 Did FBC consult parties other than those identified by the utility as "directly affected" to determine whether its assessment was correct?

Response:

FBC contacted those parties described in the Application as key stakeholders (including those directly impacted by the Project) and those discussions did not identify any further parties requiring notification. FBC is confident that its consultation efforts were as inclusive as required by the Project.

2.0 Reference: Exhibit B-1, pages 10 and 13

Preamble: At page 10 the Application states: "While capacity on the 230 kV system is sufficient, capacity on the 138 kV system, which directly feeds the area's distribution substations, is becoming increasingly constrained".

2.1 What is FBC's current forecast as to when the capacity on the 230 kV system will not be adequate to meet the load requirements in the Kelowna area?

Response:

FBC's 230 kV system will no longer be adequate to meet the load requirements when the peak load in the Kelowna area reaches 430 MW. At this load level the outage of 73 Line (LEE-DGB-RGA[1]) results in voltage violations/collapse in Kelowna requiring the need for a Static Var Compensator (SVC) for voltage support. Based on the current forecast, the Kelowna peak load will be at this level in year 2040.

2.2 There is no discussion in the Application as to the adequacy of the area's distribution substations to meet future load requirements. What is FBC's current forecast as to when the capacity of the area's distribution substations will not be adequate to meet the load requirements of the Kelowna area?

Response:

This Project will not address or affect the capacity available at the area's distribution substations. Since distribution substations supply more localized geographic areas, they do not collectively act to meet the load requirements of the Kelowna area. Rather, distribution substations typically require upgrades because of concentrated development in a specific area of the community.

A project to add a second distribution transformer at the Sexsmith substation is currently in execution. Over the upcoming five years, FBC is also planning to initiate projects to add second distribution transformers at the D.G. Bell and Duck Lake stations.

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[1] R.G. Anderson Terminal Station in Penticton.

2.2.1 Will the dates when additional capacity is required for the area's distribution substations be at all affected by which of the three alternatives set out in the current Application (pages 27-32) are chosen?

2.2.2 If yes, please explain how.

Response:

No, the alternative chosen will not affect the dates when additional capacity is required for the area's distribution substations.

3.0 Reference: Exhibit B-1, page 14

Preamble: At page 12 the Application states:

> "Other sources demonstrate a consensus view of continued, consistent growth in the Kelowna area. For example, in 2011 the City of Kelowna adopted the Kelowna 2030 Official Community Plan, anticipating the addition of 8,565 single / two unit homes and 11,520 multiple unit homes by 2030. In 2018, the City of Kelowna further predicted that the total number of new housing units required by 2040 will be between 23,000 and 25,000 units".

3.1 Based on the additions referenced in the Kelowna 2030 Official Community Plan, what does this translate into in terms of annual growth in number of homes in the area through to 2030?

<u>Response:</u>

Based on the information in the Kelowna 2030 Official Community Plan, this translates to approximately 1,000 new housing units per year through to 2030.

3.2 Similarly, what do the additions in number of new housing units between 2030 and 2040 translate into in terms of annual growth in number of homes?

<u>Response:</u>

FBC understands that the 2018 City of Kelowna prediction regarding new housing units required by 2040 is for the period from 2018 to 2040. Therefore, the total number of units would translate to approximately 1,000 to 1,100 housing units per year.

4.0 Reference: Exhibit B-1, pages 15-16

4.1 With reference to the load forecast methodology used, please explain why some/all of the potential new load discussed at page 16 (lines 16-24) is not already implicitly captured in the load forecast as set out in Table 3-5.

Response:

Only new commercial loads are "implicitly" captured in FBC's load forecast, since commercial load is forecast as a whole based on GDP growth rates from the Conference Board of Canada. For the new load referenced on page 16, which is associated with potential industrial accounts, FBC works with key account managers who work directly with customers to determine if a new load should be included in the forecast or not. If a new industrial customer is not confirmed, it is not included in the forecast. FBC has not included any new industrial accounts in this forecast.

5.0 Reference: Exhibit B-1, pages 17-20

5.1 With respect to Figure 3-3, please provide a table setting out the actual annual values of each of the five lines. For the lines setting out the Existing Summer and Winter N-1 Transformer Limits and the New Summer Threshold please provide a breakdown of the contribution of each transformer (i.e., each of the two existing at LEE, the one existing at DGB and the planned new one).

Response:

Please refer to the response to BCUC IR1 11.3 for the table setting out the actual peak load values represented in Figure 3-3. This response includes the full data set for Figure 4-1, which is the same data set as Figure 3-3.

Please refer to the response to BCUC IR1 7.2 for a description of the existing N-1 Summer and Winter N-1 Transformer Limits.

The new Summer Load Threshold is based on the following:

- The new LEE T2 transformer would have a normal summer rating of 190 MW.
- The LEE T3 and LEE T4 transformers are likely to be replaced before their ratings become constraints. As described in the response to BCUC IR1 9.1, LEE T4 is expected to be replaced between 2033 and 2038, while LEE T3 is expected to be replaced in 2045. The expectation is that these transformers would be rated at 120/160/200 MVA and would therefore have the same 190 MW normal summer rating as the new LEE T2 and DGB T2. In this manner, it is expected that the transformers could continuously support up to 570 MW of summer peak load in the event of a single terminal transformer outage (3 x 190 MW = 570 MW).
- As described in the response to BCUC IR1 14.1, a decision about the future expansion of the Kelowna transmission system will be required at the 550 MW load level; therefore, FBC has established this as the New Summer Threshold on Figure 3-3 rather than the theoretical transformer capability of 570 MW.

5.2 Given that it could take a year to procure and install a new transformer at LEE (per page 19, lines 29-30), is it the normal ratings, the emergency limits or some other values for each transformer that are considered when assessing the Kelowna area system's ability to meet the N-1 planning criteria? In responding, please explain why.

Response:

Both the normal ratings and the emergency limits for a transformer are considered when assessing the ability to meet N-1 planning criteria.

FBC's operating procedures require the post contingency flow to be brought within the emergency rating within 15 minutes and to be reduced within the normal rating level within six hours. Please refer to Section 3.4.1 of the Application for further discussion related to assessment of N-1 scenarios and transformer ratings.

5.3 Please clarify whether the transformer capacities used in Figure 3-3 are based on the emergency limits or the normal ratings.

Response:

Figure 3-3 is based on normal ratings. Please refer to the response to BCUC IR1 7.2 for a description of the 315 MW and 370 MW existing summer and winter N-1 transformer limits.

5.3.1 If normal ratings, please reconcile with the fact that the 550 MW summer system capability after the next transformer addition is based on an incremental emergency capacity of 235 MW (per page 24).

Response:

As described in the response to BCOAPO IR1 5.1, the threshold at 550 MW includes an assumption that the existing LEE T3 and LEE T4 transformers will have been replaced in advance of these transformer ratings becoming a constraint.

Based on expected transformer ratings alone, the limit could be as high as 570 MW. This is due to the fact that LEE T2, T3 and T4 and DGB T2 would all be expected to be capable of continuously supplying 190 MW at summer peak. However, as described in the response to BCUC IR1 14.1, a decision about the future expansion of the Kelowna transmission system will be required at the 550 MW load level. Accordingly, this threshold has been established at 550 MW to recognize that changes to the system may be required.

5.3.2 If emergency ratings, please reconcile with the response to question 5.2.

Response:

Please refer to the response to BCOAPO IR1 5.3.

6.0 Reference: Exhibit B-1, pages 19 and 24

Preamble: The Application states:

> "Power flow simulation studies were used to analyse single contingency scenarios. When either of the two existing LEE terminal transformers is out of service, the loading on the remaining transformer is 191 MVA (91 percent of its emergency limit) when the total Kelowna area load reaches 315 MW, which is just marginally higher than the forecast summer peak load forecast in 2021, as provided in Table 3-5. The loading on the remaining LEE transformer can be lowered by adjusting the load supply configuration in the Kelowna 138 kV system to transfer additional load to DGB. After system reconfiguration, the flow on the remaining LEE transformer is 168 MVA, which is 80 percent of the emergency limit and 100 percent of normal rating".

The Application also states:

> "The loss of one of the two transformers at LEE is the critical outage for planning purposes. If DGB transformer were to fail, the system could continue to supply all load within normal limits from LEE transformers and 138 kV lines".

6.1 Given that the DG Bell transformer is 200 MVA and each of the LEE transformers are only 168 MVA (per page 13), please explain why loss of one of the two transformers at LEE is the critical outage for planning purposes. In responding please indicate what the winter and summer supply capability to Kelowna area is if the transformer at DG Bell is out of service and the basis for the value.

<u>Response:</u>

The loss of a LEE transformer is a more critical outage compared to the outage of the DGB transformer because of the geographical distribution of load in Kelowna. More load is supplied from LEE than from DGB.

If the transformer at DGB is out of service, the winter and summer supply capabilities for the Kelowna area are as follows:

- Winter: 385 MW. At this load level, the flow on each of the LEE transformers is approximately 100 percent of the winter normal rating of T3 and T4.
- Summer: 330 MW. At this load level, the flow on each LEE transformers is approximately 99 percent of the summer normal rating of T3 and T4.

The basis of the above limits is the post contingency flow. Current operating procedures allow the post contingency flow to be above the emergency equipment rating for only fifteen minutes and above the normal equipment rating for only six hours and plans to reduce the loading must be implemented within these time frames. Beyond the load levels given above, the post contingency flows cannot be brought within the defined limits.

6.2 After the system reconfiguration, what would be the loading on the DG Bell transformer?

Response:

After the system reconfiguration, the loading on the DGB transformer is 150 MVA. This is 60 percent of the emergency rating of 250 MVA and 75 percent of the normal rating of 200 MVA.

6.2.1 If this value is less than 200 MVA, please explain why.

Response:

The Kelowna area load is supplied by three 230/138 kV transformers, LEE T3 and T4 and DGB T2. During the critical outage of a LEE transformer, the post contingency flow following system reconfiguration on the remaining LEE transformer is 168 MVA and the DGB transformer is 150 MVA.

The flow on DGB transformer is less than 200 MVA because of the geographical distribution of load in Kelowna. Under normal conditions, more load is supplied from LEE as compared to DGB. While some load is transferred over to DGB following a contingency and system reconfiguration to reduce the post contingency flow on the remaining LEE transformer, the load supplied from LEE remains higher than DGB because of the geographical distribution of the load.

7.0 Reference: Exhibit B-1, pages 19 and 22-24

Exhibit A-3, BCUC 10.2

Preamble: The Application states (page 19) that: "FBC does not own a mobile transformer of suitable size and voltage".

7.1 If not addressed in the response to BCUC 1.10.1, please provide an estimate as to the cost of a mobile transformer and how long it would take to install if located close to the LEE terminal station and one of the existing LEE transformers experienced an outage.

<u>Response:</u>

Please refer to the response to BCUC IR1 7.13, which explains why a mobile transformer is not a feasible solution.

8.0 Reference: Exhibit B-1, pages 22-23

8.1 Please outline the scope of the DR pilot currently underway in the Kelowna area (i.e., is it open to all potential DR load in the area or just specific customers?) and the basis for the 1.75 MW capacity target.

Response:

FBC estimated the DR potential of the largest 53 Commercial and Industrial (C&I) accounts in the Kelowna area. C&I customers were targeted as the best candidates due to their familiarity with demand rates and internal capacity to modify their loads in response to FBC triggered DR Events.

Based on informal learning from a BC Hydro commercial DR pilot, FBC anticipated that participation would be lower than the total potential and accordingly set the 1.75 MW winter capacity target below the total DR potential.

For the 2020 summer DR phase, FBC has widened C&I recruitment across its electric service territory to assess the potential to scale the DR pilot.

Other customer sectors (e.g., residential and small commercial) are billed on energy only rates and are inherently more difficult to recruit. However, FBC is evaluating an additional DR pilot phase that will target a specific area in Kelowna, which is primarily comprised of residential customers.

9.0 Reference: Exhibit B-1, pages 24-25

Preamble: The Application states: "The capacity gain from the DGB alternative would be lower than the LEE alternative".

9.1 Please explain why the capacity gain from the DGB alternative (Alternative C) would be lower (i.e., only 85 MW).

<u>Response:</u>

The incremental capacity gain associated with Alternative C is lower due to the distribution of load in the Kelowna area and configuration of the transmission network. Even after the reconductoring of the 138 kV 60L and 51L transmission lines under Alternative C, the capacity of transmission lines interconnected with DGB is the limiting factor. As described in Section 4.3 on page 25 of the Application, DGB is more distant from the high-load area and has only two 138 kV transmission lines compared to four at LEE. These transmission line constraints would restrict FBC from utilizing the full nameplate capacity of two transformers at DGB.

10.0 Reference: Exhibit B-1, pages 27-27 and 38

Exhibit A-3, BCUC 1.18.1 and 1.18.4

10.1 With reference to the drawings provided in response to BCUC 1.18.1 and 1.18.4, please demonstrate why "a ring bus configuration results in a more than 50 percent reduction in outage minutes per year as compared to a split bus configuration" (per page 27).

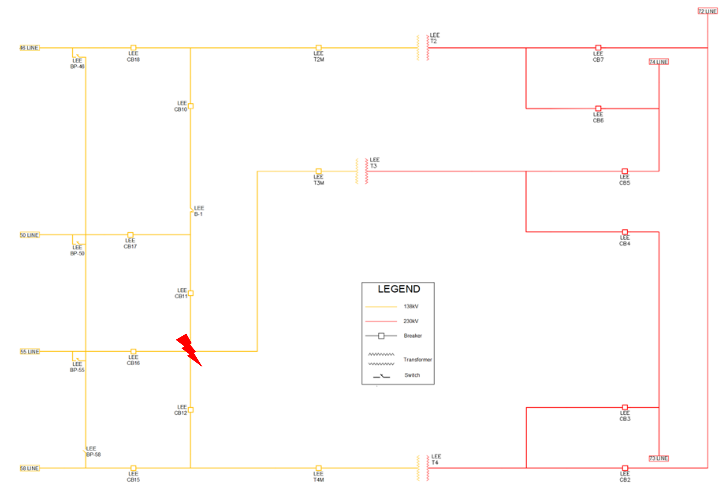
Response:

Please refer to the diagrams below which demonstrate why a ring bus configuration results in a reduction in outage minutes per year, as compared to a split bus configuration. The analysis assumes the following circumstances:

- The fault occurs at the T3 connection to the 138 kV station bus; and
- The best case time for transferring transmission load between lines in the Kelowna 138 kV ring is six minutes.

The diagrams below illustrate that in a ring bus configuration 55L line remains in service, reducing the customer outage minutes experienced to zero. Conversely, the split bus configuration results in a minimum of 60,780 customer outage minutes. This example illustrates a scenario where a ring bus configuration can potentially reduce outage minutes by 100 percent.

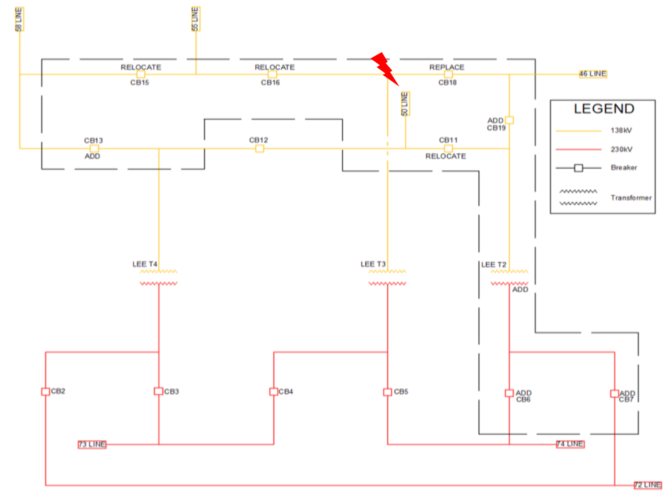
Split Bus Configuration



Normal Operating Conditions	All Breakers are closed. All LEE Bus 2 BP Switches are normal open. SAU 50-BP and OKM 51-BP are normal open
Fault	Bus fault at the T3 connection.
Protection Scheme Response	Assumes no trip coils fail to operations. LEE CB11, CB12, CB55, and T3M trip.
Outage Impact	Loss of T3 and 55L

Customer Outage Minutes	
55L Impacted Stations & Customers	
Hollywood Substation	
Customer Count	10130
Restoration Source	Restore via 50L
Restoration Time	6
Split Bus Outage Minutes	
Total Customer Outage Minutes	60780

Split Bus Configuration



Normal Operating Conditions	All bus breakers are normal closed. SAU 50-BP and OKM 51-BP are normal open
Fault	Bus fault at the T3 connection.
Protection Scheme Response	Assumes no trip coils fail to operations. LEE CB16, CB18, CB4, and CB5 trip
Outage Impact	Loss of T3.

Customer Outage Minutes	
55L Impacted Stations & Customers	
Hollywood Substation	
Customer Count	10130
Restoration Source	N/A
Restoration Time	0
Ring Bus Outage Minutes	
Total Customer Outage Minutes	0

10.2 With reference to the drawings provided in response to BCUC 1.18.1 and 1.18.4, please demonstrate why "a breaker failure on a split bus causes a larger outage than on a ring bus" (per page 27).

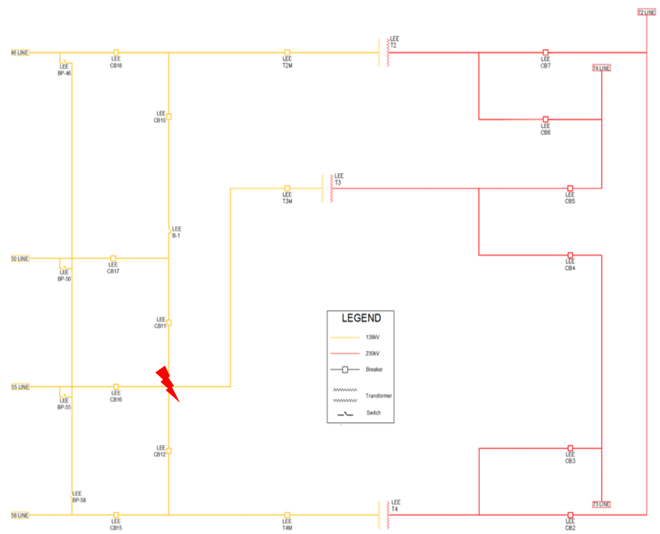
Response:

Please refer to the diagrams below which demonstrate why a breaker failure on a split bus causes a larger outage than on a ring bus configuration. The analysis assumes the following circumstances:

- The fault occurs at the T3 connection to the 138 kV station bus;
- The best case time for transferring transmission load between lines in the Kelowna 138kV ring is six minutes; and
- The best case time for restoring a line to the system via a by-pass switch in the split bus configuration is 2-hours.

The diagrams below illustrate that the customer outage minutes experienced in a ring bus configuration are reduced to 31,014 minutes. Conversely, the split bus configuration results in a minimum of 1,895,820 customer outage minutes. This example illustrates a scenario where a ring bus configuration can potentially reduce outage minutes by 98 percent.

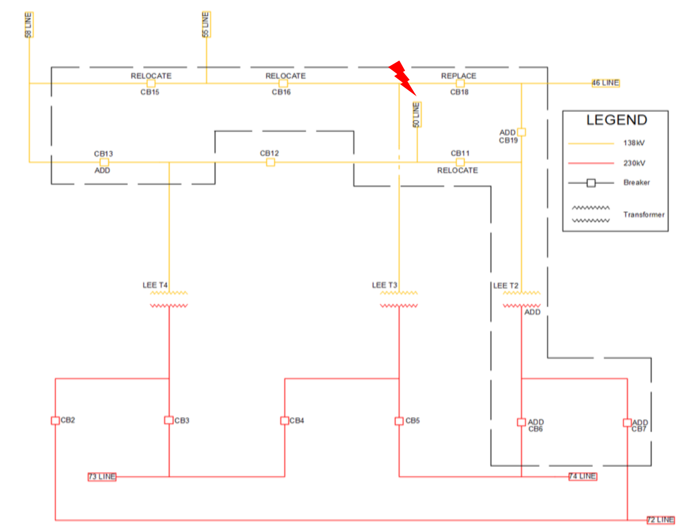
Split Bus Configuration



Normal Operating Conditions	All Breakers are closed. All LEE Bus 2 BP Switches are normal open. SAU 50-BP and OKM 51-BP are normal open
Fault	Bus fault at the T3 connection.
Protection Scheme Response	Normal Protection Scheme: LEE CB11, CB12, CB55, and T3M trip. Bus Breaker (CB11) fails to operate Secondary Protection Trips CB10 and CB17.
Outage Impact	Loss of T3, 55L, and 50L

Customer Outage Minutes	
55L Impacted Stations & Customers	
Hollywood Substation	
Customer Count	10130
Restoration Source	Restore via 51L
55L Restoration Time	6
50L Impacted Stations	
Glenmore Substation	
Customer Count	9787
Recreation Substation	
Customer Count	5505
Restoration Source	Restore through 50-BP
50L Restoration Time	120
Split Bus Outage Minutes	
Total Customer Outage Minutes	1895820

Split Bus Configuration



Normal Operating Conditions	All bus breakers are normal closed. SAU 50-BP and OKM 51-BP are normal open
Fault	Bus fault at the T3 connection.
Protection Scheme Response	Normal Protection Scheme: LEE CB16, CB18, CB4, and CB5 Bus Breaker (CB18) fails to operate Secondary Protection Trips CB19
Outage Impact	Loss 46L and T3

Customer Outage Minutes	
46L Impacted Stations & Customers	
Duck Lake Substation	
Customer Count	1559
Ellison Substation	
Customer Count	3610
Restoration Source	Restore via 50L
50L Restoration Time	6
Ring Bus Outage Minutes	
Total Customer Outage Minutes	31014

10.3 With reference to the drawings provided in response to BCUC 1.18.1 and 1.18.4, please demonstrate why "the ring bus configuration is easier to maintain and operate than split bus because any single breaker can be taken out of service without the need for bus reconfiguration" (per page 27).

Response:

With a ring bus configuration, the operation and protection scheme of the station are unaffected by an outage of any one element. Conversely, in a split bus configuration, removing a station element from service leads to complicated offloading, switching and isolation procedures, which could differ between each element, depending on the station set up.

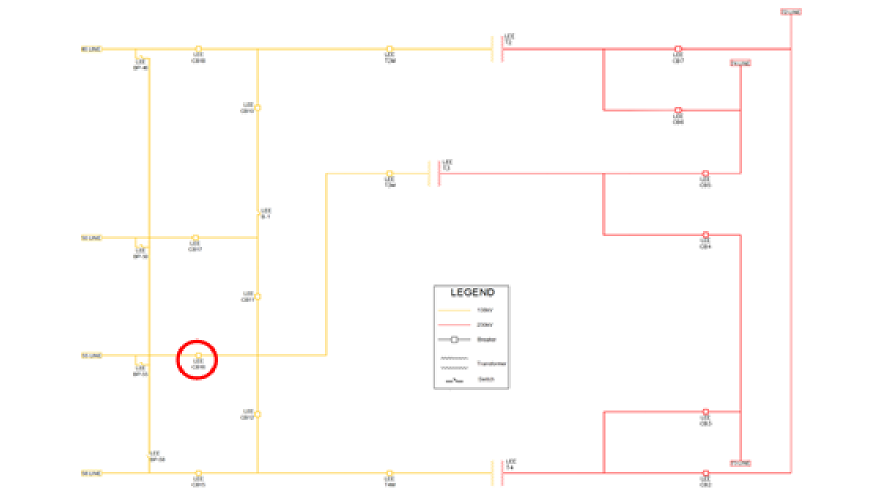
The demonstration on the following page assumes the following circumstances:

- CB16 is undergoing maintenance;
- The best case time lapses for isolation and restoration; and
- Restoration takes approximately the same time as isolation.

The demonstration illustrates that in a ring bus configuration, the isolation and restoration procedure is shorter and takes less time to implement at approximately 3.25 hours. Conversely, the split bus configuration requires a minimum of 13 hours to perform all of the preparation and implementation. This example illustrates approximately a time savings of approximately 75 percent.

Furthermore, the demonstration below illustrates that in a split bus configuration, two transmission lines are protected on the same relay scheme under maintenance conditions. This reduces the system reliability because a transmission fault would result in larger customer outage impact for a longer duration of time. In comparison, a ring bus maintains an independent transmission line protection scheme.

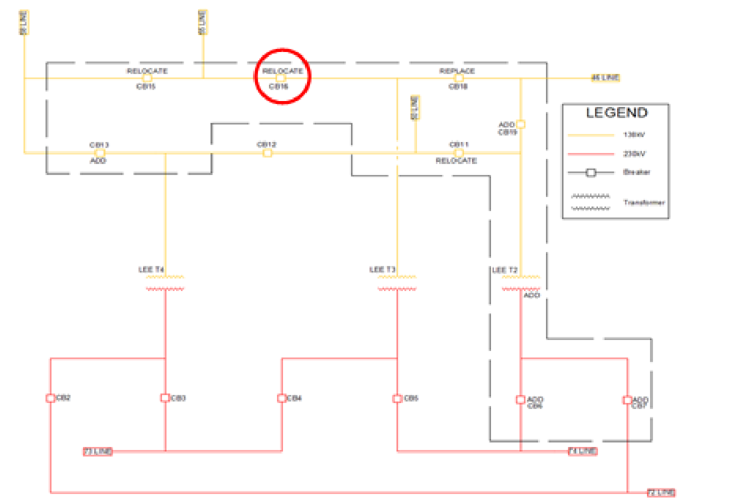
Split Bus Configuration



Normal Operating Conditions	All Breakers are closed. All LEE Bus 2 BP Switches are normal open. SAU 50-BP and OKM 51-BP are normal open
Maintenance Zone	CB16
Restoration	Assumes Restoration Through 55-BP via 50L CB (CB17).
Isolation Procedure (Sample)	Switchman contacts Control Centre SCC performs external contacts to inform switching to start. While maintaining communication between the site crew and Control Centre: • On-site crew performs relay settings changes & test alterations. • On-site crew closes LEE BP-55 (Energizes by-pass bus). • On-site crew closes LEE BP-50 (Parallels 50L and 55L). • Control Centre performs of paralleling confirmation. • Control Centre opens CB16. • On-site crew confirm CB16 open. • On-site crew opens 16-1 and 16-2.
Reliability Impact	2 transmission lines are now protected by 1 relay scheme. Larger and longer customer outages in a transmission line fault.

	Best Case Scenario
Engineering P&C Prep. Time	4 hours
Crew Prep. Time	4 hours
Control Centre Prep Time	1 hour
On-site Isolation Time	2 hours
On-site Restoration Time	2 hours
Total Isolation/Restoration Time	13 hours

Split Bus Configuration



Normal Operating Conditions	All bus breakers are normal closed. SAU 50-BP and OKM 51-BP are normal open
Maintenance Zone	CB16
Restoration	Continual supply via ring bus.
Protection Scheme Response	Switchman contacts Control Centre SCC performs external contacts to inform switching to start. While maintaining communication between the site crew and Control Centre: • Control Centre opens CB16. • On-site crew confirm CB16 open. • On-site crew opens 16-1 and 16-2.
Reliability Impact	All transmission line still protected by independent protection scheme.

	Best Case Scenario
Engineering P&C Prep. Time	0 hours
Crew Prep. Time	2 hours
Control Centre Prep Time	15 minutes
On-site Isolation Time	30 minutes
On-site Restoration Time	30 minutes
Total Isolation/Restoration Time	3.25 hours

10.4 With reference to the drawings provided in response to BCUC 1.18.1 and 1.18.4, please demonstrate why "the ring bus configuration has less complicated protection and switching schemes than split bus because each transformer and transmission line has its own discrete node in the bus between two breakers" (per page 27).

Response:

In a split bus configuration, there are multiple branches of the system (i.e., transformer and transmission line) protected from the same node. As a result, the protection scheme is configured to isolate the multiple branches of the system in fault. Under maintenance conditions, this scheme requires numerous changes to isolate a single device.

In comparison, a ring bus configuration applies a single protection scheme to a single system branch. As a result, in a fault, the system only isolates one branch. In a maintenance event, single branches can be isolated without any changes required to the protection scheme.

These outcomes are demonstrated for the system in fault in the response to BCOAPO IR1 10.1 and under maintenance conditions in the response to BCOAPO IR1 10.3.

11.0 Reference: Exhibit B-1, page 26

Preamble: The Application states:

> "The ring bus configuration reduces safety risk as compared to split bus because it provides a clear zone of isolation when working on equipment that is free from complex transfer buses and switches".

The Application also states:

> "The ring bus configuration is less prone to human error when operating, resulting in fewer instances of mis-operation than a split bus".

11.1 It is noted that FBC has a number of terminal stations with a ring bus configuration (per page 27). In the last five year how many safety incidents have occurred at the LEE terminal station as compared to comparable terminal stations with a ring bus configuration (please discuss both actual safety incidents leading to injury/lost time as well as "near" incidents).

Response:

In the last five years, there have been no safety, near miss or human error incidents at LEE terminal station. With comprehensive work methods, training, and the diligent safety focus of personnel, it is possible to operate and maintain the existing LEE terminal station. Please also refer to the response to BCUC IR1 17.5 for a discussion of additional measures for the LEE terminal station.

The lack of incidents at LEE terminal station does not imply that the split bus configuration is low risk. A safety incident in this type of terminal has a very high consequence potential. Therefore, even if the frequency of past incidents or probability of future incidents is low, the risk is high. Please also refer to the response to BCUC IR1 12.4 for a discussion of the reduction in safety risk of a ring bus versus split bus configuration.

11.2 In the last five years what was the number of human error incidents at LEE related to the split bus configuration and how does this compare with the number of human error incidents at comparable stations with a ring bus configuration?

Response:

Please refer to the response to BCOAPO IR1 11.1.

12.0 Reference: Exhibit B-1, pages 28 and 38

Exhibit A-3, BCUC 1.18.1

Preamble: The Application states:

"Construction would include the expansion of the existing 230 kV ring bus by one breaker to accommodate the additional transformer. This involves the addition of two new 230 kV circuit breakers (one of which will replace an existing obsolete breaker).

The 138 kV bus would be reconfigured from a split bus to a seven breaker ring bus. This portion of the work would include relocating three existing breakers to new locations, salvaging four existing obsolete breakers, and installing three new breakers. The total 138 kV breaker count would decrease from ten to nine, as there are two 138 kV breakers that are used for switching the existing capacitor banks in addition to those in the new seven breaker ring."

12.1 With reference to the simple line drawing of the current configuration of the LEE terminal station (provided in response to BCUC 1.18.1), please identify the equipment that, under Alternative A, will be: i) replaced, ii) relocated or iii) removed.

<u>Response:</u>

In this response, FBC assumes the question is intended to reference the response to BCUC IR1 18.2. With reference to the simplified diagram provided in that response, under Alternative A the following breakers would be:

- Replaced:
  - CB18 (138 kV)
- Relocated:
  - CB11 (138 kV)
  - CB15 (138 kV)
  - CB16 (138 kV)
- Removed:
  - CB1 (230 kV)
  - CB17 (138 kV)

- CBT3M (138 kV)
- CBT4M (138 kV)

13.0 Reference: Exhibit B-1, pages 35 and 53

Preamble: The Application states: "The schedule risk is more complex and requires transmission line outages for Alternative A".

The Application also states: "Outage windows required for 138 kV transmission lines can be accommodated; and Outage windows required for modifications to 230 kV ring bus can be accommodated".

13.1 Please describe the number and duration of transmission line outages that will be required for Alternative A. Please also outline when during the project schedule (per Figure 5-3) these are expected to be required.

Response:

The transmission line outages required under Alternative A are as follows:

- 50L Transmission circuit: 3-4 day outage for structure replacement and cutovers – to be scheduled during Phase 4, Stage 1.
- 55L Transmission circuit: 3-4 day outage for structure replacement and cutovers – to be scheduled during Phase 4, Stage 1 subsequent to 50L return of service.
- 58L Transmission circuit: 2-3 day outage for structure replacement and cutovers – to be scheduled during Phase 4, Stage 1 subsequent to 55L return of service.
- 55L Transmission circuit: 1 day outage for cutovers to new A-Frame – to be scheduled during Phase 4, Stage 4.
- 58L Transmission circuit: 1 day outage for cutovers to new A-Frame – to be scheduled during Phase 4, Stage 4 subsequent to 55L return of service.
- 46L Transmission circuit: 1 day outage for cutovers to new A-Frame – to be scheduled during Phase 4, Stage 5.
- 50L Transmission circuit: 1 day outage for cutovers to new A-Frame – to be scheduled during Phase 4, Stage 7.

FBC expects that customers will be unaffected by the Transmission line outages required to reconfigure the lines for Alternative A. All transmission line work will be completed with only one transmission circuit de-energized at a time, and hence uninterrupted service to the area Substations via the Kelowna Transmission Ring System. Transmission line outages would be coordinated as best as possible to minimize risk exposure as the system operates in an N-1 condition. Cutovers would be scheduled during optimal conditions, such as non-peak load situations and favourable weather forecast.

13.2 Would Alternative B require transmission line outages?

13.2.1 If yes, please describe the number and duration of transmission line outages that will be required.

Response:

The transmission outages that would be required under Alternative B are as follows:

- 50L Transmission circuit: 4-5 day outage for structure replacement and cutovers.
- 46L Transmission circuit: 3 day outage for cutovers subsequent to 50L return of service.
- 55L Transmission circuit: 3-4 day outage for structure replacement and cutovers subsequent to 46L return of service; and
- 50L and 55L Transmission circuits: Common 4 hour brief outage for circuit tie-in conductor work. Common 50L/55L outage can be completed without interruption to customers.

Aside from the 50L and 55L common outage (which may be completed without interruption to customers), all transmission line work would be completed with only one transmission circuit de-energized at a time, and hence uninterrupted service to the area distribution substations via the Kelowna Transmission Ring System. Transmission line outages would be coordinated as best as possible to minimize risk exposure as the system operates in an N-1 condition. Cutovers would be scheduled during optimal conditions, such as non-peak load situations and favourable weather forecast.

13.3 To what extent will customers be affected by the transmission line outages required for Alternative A?

Response:

Please refer to the response to BCOAPO IR1 13.1.

13.4 To what extent would customers be affected by the transmission line outages required (if any) for Alternative B?

Response:

Please refer to the response to BCOAPO IR1 13.2.1.

14.0 Reference: Exhibit B-1, pages 35-36

Preamble: The Application states (page 35): "FBC also rejects Alternative C on the basis of the financial evaluation".

The Application states (page 36): "From a financial perspective, the rate impact of Alternative A is approximately 0.10 percentage points higher than Alternative B."

The Application also states (page 36): "Of the three alternatives considered, Alternative A provides the best technical solution. …….On this basis, Alternative A is selected as the preferred solution for the KBTA Project."

14.1 How much higher would the rate impact from Alternative A need to be in order for Alternative B to be considered the "preferred solution"?

<u>Response:</u>

FBC did not utilize a threshold rate increase to compare and select amongst project alternatives. Rather, the determination of the preferred alternative for the KBTA Project is based on a balanced approach as set out in Section 4.5 of the Application. In addition to the financial analysis and rate impacts, the determination included the ability of the alternative to meet the planning criteria, the safety and operability of the alternative, the impact on system reliability, the potential for future expansion, and the associated project risk.

As demonstrated in Table 4-1, Alternative A is superior to Alternative B in all technical aspects evaluated, is approximately equivalent in terms of project risk, and has a slightly higher rate impact than Alternative B. On balance, Alternative A is a superior solution in FBC's view.

15.0 Reference: Exhibit B-1, pages 54-55

15.1 If not considered confidential, please provide total value of the assets that will be placed in-service each year (i.e., without the plant asset account detail).

<u>Response:</u>

The following table provides the total value of assets, including removal costs that will be placed into service each year.

Item $000's	2022	2023	2024	Total
Construction	1,340	20,206	774	**22,320**
Removal	711	257	-	**968**
Total	**2,052**	**20,462**	**774**	**23,288**

16.0 Reference: Exhibit B-1, page 57

16.1 To date, has any further information been requested by the City of Kelowna?

16.1.1 If yes, what has been requested and what has been provided?

<u>Response:</u>

Please refer to the response to BCUC IR1 31.1.

17.0 Reference: Exhibit B-1, pages 4 and 58

17.1 Is the Project survey referenced on page 4 the same survey as the on-line survey referenced on page 58 (line 10)?

17.1.1 If not, to whom was the Project survey referenced on page 4 distributed, overall, how many parties/persons were surveyed, what issues did the survey address and how many responses were received?

Response:

Confirmed. The Project survey mentioned on page 4 of the Application and the on-line survey mentioned on page 58 refer to the same survey available on the Project webpage.

18.0 Reference: Exhibit B-1, Appendix F

18.1 The Draft Order for the Project's approval provided in Appendix F makes reference to both Quarterly Reports and a Final Report being filed with the BCUC.

18.1.1 Is it FBC's intention that these Reports be available publicly?

18.1.2 If not, why not?

18.1.3 If yes, how does FBC propose to do so?

<u>Response:</u>

FBC does not intend to make the reports publicly available. FBC files its progress and final reports for CPCN projects with the BCUC on a confidential basis. Included in the reports is detailed cost information which has been determined by the BCUC to be confidential during the regulatory proceeding because of the potential for its disclosure to prejudice FBC's negotiating position when procuring contracts, including contracts for future projects. Ongoing scrutiny of a project by external parties following BCUC approval is unnecessary under normal circumstances; one of the BCUC's roles is to review the quarterly reports and, if necessary, requests further information to monitor the progress of projects it has approved. Finally, FBC provides information about its approved CPCN projects, including forecast costs, in its Annual Reviews for rate setting purposes.

19.0 Reference: Exhibit E-1 and Exhibit E-2

19.1 To date two Letters of Comment have been posted on the Commission's website, both addressing issues regarding aesthetic improvement. Please outline FBC's plans to address the issues raised.

Response:

Please refer to the response to BCUC IR1 32.4 which describes FBC's intentions regarding aesthetic improvements to the station.