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November 6, 2015

Via Email
Original via Mail

British Columbia Public Interest Advocacy Centre
Suite 208 – 1090 West Pender Street
Vancouver, B.C. V6E 2N7

Attention: Ms. Tannis Braithwaite, Executive Director

Dear Ms. Braithwaite:

Re: FortisBC Inc. (FBC)

Application for a Certificate of Public Convenience and Necessity (CPCN) for the Kootenay Operations Centre (the Application)

Response to the British Columbia Public Interest Advocacy Centre representing the British Columbia Old Age Pensioners' Organization, Active Support Against Poverty, Disability Alliance BC, Council of Senior Citizens' Organizations of BC, and the Tenant Resource and Advisory Centre *et al.* (BCOAPO) Information Request (IR) No. 2

On July 9, 2015, FBC filed the Application referenced above. In accordance with the British Columbia Utilities Commission Order G-124-15 setting out the Regulatory Timetable for the review of the Application, FBC respectfully submits the attached response to BCOAPO IR No. 2.

If further information is required, please contact the undersigned.

Sincerely,

FORTISBC INC.

Original signed by: Ilva Bevacqua

For: Diane Roy

Attachments

cc: Commission Secretary
Registered Parties (e-mail only)

1 Reference: Exhibit B-5, BCOAPO 1.5.1 (page 6)

Exhibit B-4, BCUC 1.12.2 (page 67)

1.1 Please confirm that current charges to third parties for services provided by the Station Services Group include an allocation of Generation overheads that incorporates the operating costs for its current location (i.e. Warfield).

Response:

Generation overheads are specific to Generation only. Operating costs for the Warfield Complex (where the Station Services Group resides) are not recovered from third party customers.

1.2 Does the $150,000 in Net Generation Recoveries represent: a) the full allocation of KOC operating costs, or b) the increase in allocated costs as a result of moving from Warfield to the KOC (i.e. the full allocation of KOC operating costs less the Warfield-related operating costs previously allocated to third parties)? If the former, please provide the net increase in allocated operating costs that will be recovered from third parties serviced by the Station Services Group.

Response:

Neither option (a) nor (b) accurately represents the $150 thousand in Net Generation Recoveries. To clarify, the $190 thousand in KOC operating costs allocated to Generation will form a component of the Generation overhead allocation pool. The overhead pool consists of related support costs such as fleet, facilities and management. The pool is then distributed on the basis of productive labour hours worked at each FBC owned and operated hydroelectric facility. The $150 thousand represents the facility dollars recovered based on the allocation of those productive hours and is used to offset Generation's allocation of the KOC operating costs. The Net Generation Recovery is not related to the Station Services Group. Please refer to the response to BCOAPO IR 2.9.1 for further details.

For a breakdown of the O&M by location, including the Station Services O&M and the Generation O&M, please refer to the response to BCUC IR 1.1.3. As shown in that response, there are no incremental third party cost recoveries related to Station Services as a result of the KOC Project. Please also refer to the response to BCUC IR 2.2.4 which provides an update to O&M savings associated with the Station Services travel time (line item "Travel Time C&M" in

Attachment 2.4E). The estimated O&M savings has decreased from approximately $144 thousand to $88 thousand.

2 Reference: Exhibit B-4, BCUC 1.1.2 (page 6)

2.1 Please explain why the proposed space requirements by site are considered confidential when comparable information has been provided for the existing facilities.

Response:

The space requirements have been provided for existing facilities that do not identify the location of Critical Assets. Certain space requirements were provided confidentially to protect the location of Critical Assets, the release of which could potentially jeopardize the safety and security of the Company's system or assets.

2.2 Please complete Table 3 for those sites that are not considered confidential.

Response:

Please refer to the response to BCOAPO IR 2.2.1. FBC provided the information it does not consider to be confidential in the response to BCUC IR 1.1.2.

3 Reference: Exhibit B-4, BCUC 1.2.3 (page 12)

3.1 Why was the economic analysis performed for only five years (2017-2021)? What is the expected life of: a) the RTU system and b) the ground source heat pump?

Response:

This response also addresses BCOAPO IRs 2.3.2 and 2.3.3.

The analysis was limited to five years because that length of time was sufficient to demonstrate the expected savings from using the rooftop units (RTUs) compared to the ground source heat pump. The expected life of the RTU system and the ground source heat pump are comparable at approximately 20 to 25 years. As such, extending the analysis period would not impact the decision to use RTUs because savings of approximately $50 thousand per year would be forecast to continue.

The Average Energy Cost of procurement is not based on the LRMC of firm energy. The LRMC is a 30 year levelized calculation based on the BC Hydro Standing Offer Program which represents the BC clean resources of $111.96/MWh.[1] As stated above, the economic analysis provided in the response to BCUC IR 1.2.3 was a short term analysis of 5 years and hence the LRMC was not used.

Whether analyzed for the 5 year period or over 25 years, when FBC's LRMC for BC clean resources and a 9% line loss are used, the average yearly savings effect of the RTU remains in the range of $40 thousand (please refer the following table).

[1] FBC 2014 DSM Expenditures 2015-2016, Exhibit B-1 - Application for Approval of DSM Expenditures for 2015 and 2016, pp. 11-14; FBC 2012-2013 Revenue Requirements and Review of Integrated System Plan, Exhibit B-1-2 – 2012 Integrated System Plan, Vol. 2: 2012 Long Term Resource Plan, Appendix B – 2011 FortisBC Energy & Capacity Market Assessment, pp. 26-29.

($000s)

				2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041
Additional Cost of Plant				(575.0)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Depreciation	2.80%			-	16.1	16.1	16.1	16.1	16.1	16.1	16.1	16.1	16.1	16.1	16.1	16.1	16.1	16.1	16.1	16.1	16.1	16.1	16.1	16.1	16.1	16.1	16.1	16.1
Net Book Value				(575.0)	(558.9)	(542.8)	(526.7)	(510.6)	(494.5)	(478.4)	(462.3)	(446.2)	(430.1)	(414.0)	(397.9)	(381.8)	(365.7)	(349.6)	(333.5)	(317.4)	(301.3)	(285.2)	(269.1)	(253.0)	(236.9)	(220.8)	(204.7)	(188.6)
Rate Base				**(287.5)**	**(567.0)**	**(550.9)**	**(534.8)**	**(518.7)**	**(502.6)**	**(486.5)**	**(470.4)**	**(454.3)**	**(438.2)**	**(422.1)**	**(406.0)**	**(389.9)**	**(373.8)**	**(357.7)**	**(341.6)**	**(325.5)**	**(309.4)**	**(293.3)**	**(277.2)**	**(261.1)**	**(245.0)**	**(228.9)**	**(212.8)**	**(196.7)**
Financing Cost & Taxes																												
Cost of Equity	9.15%	Equity%:	40%	(10.5)	(20.8)	(20.2)	(19.6)	(19.0)	(18.4)	(17.8)	(17.2)	(16.6)	(16.0)	(15.4)	(14.9)	(14.3)	(13.7)	(13.1)	(12.5)	(11.9)	(11.3)	(10.7)	(10.1)	(9.6)	(9.0)	(8.4)	(7.8)	(7.2)
Cost of Debt	5.3%	Debt%:	60%	(9.1)	(18.0)	(17.5)	(17.0)	(16.4)	(15.9)	(15.4)	(14.9)	(14.4)	(13.9)	(13.4)	(12.9)	(12.4)	(11.8)	(11.3)	(10.8)	(10.3)	(9.8)	(9.3)	(8.8)	(8.3)	(7.8)	(7.3)	(6.7)	(6.2)
Depreciation cost				-	(16.1)	(16.1)	(16.1)	(16.1)	(16.1)	(16.1)	(16.1)	(16.1)	(16.1)	(16.1)	(16.1)	(16.1)	(16.1)	(16.1)	(16.1)	(16.1)	(16.1)	(16.1)	(16.1)	(16.1)	(16.1)	(16.1)	(16.1)	(16.1)
Income Tax				4.4	2.6	1.5	0.6	(0.2)	(1.0)	(1.7)	(2.3)	(2.8)	(3.3)	(3.8)	(4.1)	(4.5)	(4.8)	(5.0)	(5.2)	(5.4)	(5.5)	(5.7)	(5.8)	(5.8)	(5.9)	(5.9)	(5.9)	(5.9)
Net Revenue Impact				**(15.3)**	**(52.3)**	**(52.2)**	**(52.0)**	**(51.8)**	**(51.4)**	**(51.0)**	**(50.5)**	**(50.0)**	**(49.4)**	**(48.7)**	**(48.0)**	**(47.2)**	**(46.4)**	**(45.5)**	**(44.6)**	**(43.7)**	**(42.8)**	**(41.8)**	**(40.8)**	**(39.8)**	**(38.7)**	**(37.6)**	**(36.5)**	**(35.4)**
Energy Cost Impact (Lower Efficiency Plant):																												
Long Run Marginal Cost (LRMC) of energy procurement	$k/kWh			0.00011	0.00011	0.00011	0.00011	0.00011	0.00011	0.00011	0.00011	0.00011	0.00011	0.00011	0.00011	0.00011	0.00011	0.00011	0.00011	0.00011	0.00011	0.00011	0.00011	0.00011	0.00011	0.00011	0.00011	0.00011
Incremental Energy Consumed by Mechanical Plant (Including line losses)	kWh			66,015	66,015	66,015	66,015	66,015	66,015	66,015	66,015	66,015	66,015	66,015	66,015	66,015	66,015	66,015	66,015	66,015	66,015	66,015	66,015	66,015	66,015	66,015	66,015	66,015
Incremental Unmetered Power Purchase Cost (Post Tax)	$k			5.47	5.47	5.47	5.47	5.47	5.47	5.47	5.47	5.47	5.47	5.47	5.47	5.47	5.47	5.47	5.47	5.47	5.47	5.47	5.47	5.47	5.47	5.47	5.47	5.47
Savings Achieved due to Mechanical System Change	**$k**			**(9.8)**	**(46.8)**	**(46.7)**	**(46.6)**	**(46.3)**	**(46.0)**	**(45.5)**	**(45.0)**	**(44.5)**	**(43.9)**	**(43.2)**	**(42.5)**	**(41.7)**	**(40.9)**	**(40.1)**	**(39.2)**	**(38.3)**	**(37.3)**	**(36.3)**	**(35.3)**	**(34.3)**	**(33.2)**	**(32.2)**	**(31.1)**	**(30.0)**

NPV of Savings Achieved due to Mechanical System Change	**(540)**

3.2 Is the Average Energy Cost of "procurement" based on FortisBC's forecast LRMC of firm energy? If not, why not?

Response:

Please refer to the response to BCOAPO IR 2.3.1.

3.3 As applicable, please redo the analysis using a period reflective of the life of the equipment and FortisBC's LRMC of firm energy.

Response:

Please refer to the response to BCOAPO IR 2.3.1.

4 Reference: Exhibit B-4, BCUC 1.3.3 (page 16)

4.1 How many additional FTEs can be accommodated by the 8% growth allowance?

Response:

An addition of 4 FTE office staff can be accommodated by the 8% growth allowance.

4.2 To what use will this additional space be put prior to it being required to accommodate future employee growth?

Response:

The current space allocated for growth in the KOC office building will be used as circulation and collaboration space until the space is required for employee workstations.

5 Reference: Exhibit B-4, BCUC 1.4.1 (page 17)

5.1 What is the basis for assuming a future inflation rate of approximately 2.3%?

<u>Response:</u>

The basis for the forecast inflation rate of approximately 2.3% is the 2014 forecasted CPI / AWE rate in Exhibit B-1, Volume 1 of FBC's Application for Approval of a Multi-Year Performance Based Ratemaking Plan, page 44. FBC notes that the same inflation rate was applied to all alternatives in the referenced IR response, such that the difference between 2.3% and a different rate would not have an impact on the ranking of alternatives.

6 Reference: Exhibit B-4, BCUC 1.7.3 (page 33)

6.1 Are there any inefficiencies that result from not duplicating the transformer and regulator pit at the KOC (e.g. increased staff travel time when needing to use the existing facilities at the Warfield complex)? If so, what are they, and have they been incorporated into the estimated KOC operating costs and savings (per Table 5-1)?

<u>Response:</u>

As described in the response to BCUC IR 1.7.3, the transformer bay and pit located at the Warfield Complex is used infrequently by two Meter Technicians. The Meter Technician role is different from that of the Electricians and CPC Technologists as Meter Technicians do not complete work at substations but rather at residential, commercial and industrial customer properties. In the event an issue is found with a meter or transformer, the equipment is temporarily relocated for repair to the pit located at the Warfield Complex. As the Meter Technicians cover a large territory which ranges from Rock Creek to Creston and north to Kaslo and Slocan City, and these repairs are infrequent, FBC does not believe inefficiencies result from not duplicating the transformer and regulator pit at the KOC and therefore does not recommend duplication of the asset.

7 Reference: Exhibit B-4, BCUC 1.9.2.3 (pages 47-48)

7.1 Please update Table 7-2 from the Application (Section 7.3.2) to reflect the new expected service life for the KOC building.

Response:

Table 7-2 provided the derivation of the proposed composite rate of 1.9% and is no longer applicable. Based on the Gannett Fleming opinion in Attachment 9.2.3, provided in response to BCUC IR 1.9.2.3(a), Table 7.2 would be changed as follows:

Table 7-2: Depreciation Rate for the KOC Building

BCUC Account	Particular	2015$ $000's	Duration	Provision $/Year
390	KOC Structure	$12,218	2.5%	$305
	Composite Average Life		40 Years	

7.2 With respect to the 2015 Depreciation Study, what are the proposed depreciation rates for Accounts 390.10 and 390.20?

Response:

The recommended depreciation rates from the 2015 Depreciation Study by Gannett Fleming are 3.20% for Structures – Masonry (390.10) and 2.14% for Operations Buildings (390.20). The composite average of these two sub-categories is 2.77%.

7.3 Please clarify whether the effective depreciation rate for the KOC building will be 2.5% or 2.77%.

Response:

For the revised financial analysis, the effective depreciation rate is 2.5% (1/40 years). This is consistent with the opinion of Gannett Fleming that the composite average life of the building would be in the range of 35 to 40 years. It is also consistent with the underlying premise that the expected average life of a new Operations building is 40 years, which is close to the weighted average rate of 2.77% for Masonry Structures (390.10) and Operations Buildings (390.20).

7.4 Please update Table 5-6 using the forty year time period referred to in the response to BCUC 1.9.2.3.

Response:

Updated Table 5-6: Summary of Financial Analysis of Alternative 5 at a 1.9% depreciation rate and Alternative 5 at a 2.5% depreciation rate is shown below. The column showing a 1.9% depreciation rate is the same as that filed in Exhibit B-1 of the Application.

	Alternative 5: 1.9% Depreciation Rate, 50 Year Analysis Period	Alternative 5: 2.5% Depreciation Rate, 40 Year Analysis Period
As-Spent Capital Costs	$20.651	$20.651
2018 / 2019 Rate Base	2018: $20.459	2018: $20.409
Incremental Property Taxes – 2015$	$0.419	$0.419
Gross Incremental O&M Expense – 2015$	$(0.025)	$(0.025)
PV of Incremental Revenue Requirement	$33.912	$33.002
DCF – NPV	$(0.060)	$(0.277)
2018 / 2019 Rate Increase	0.7%	0.7%

The Gannett Fleming opinion is specific to Alternative 5, but for comparison purposes the two tables below show the financial summary results over a 40 year period, also depreciating Masonry Structures at 2.5%, for Alternatives 2 and 3.

	Alternative 2: Generation 3.2% Depreciation Rate, 30 Year Analysis Period SCC / BCC: 2.3% Depreciation Rate, 45 Year Analysis Period	Alternative 2: 2.5% Depreciation Rate, 40 Year Analysis Period
As-Spent Capital Costs	$24.628	$24.628
2018 / 2019 Rate Base	2019: $23.764	2019: $23.899
Incremental Property Taxes – 2015$	$0.290	$0.290
Gross Incremental O&M Expense – 2015$	$0.151	$0.151
PV of Incremental Revenue Requirement	$39.366	$40.098
DCF – NPV	$(0.681)	$(0.473)
2018 / 2019 Rate Increase	0.9%	0. 9%

	Alternative 3: 2.3% Depreciation Rate, 45 Year Analysis Period	Alternative 3: 2.5% Depreciation Rate, 40 Year Analysis Period
As-Spent Capital Costs	$30.019	$30.019
2018 / 2019 Rate Base	2019: $29.660	2019: $29.645
Incremental Property Taxes – 2015$	$0.310	$0.310
Gross Incremental O&M Expense – 2015$	$0.137	$0.137
PV of Incremental Revenue Requirement	$45.930	$45.594
DCF – NPV	$(0.570)	$(0.672)
2018 / 2019 Rate Increase	0.9%	0. 9%

7.5 Please explain why the time period for the financial analysis was shortened to 40 years

Response:

The time period of the financial analysis has been decreased from 50 years to 40 years because the expected composite average life of the building has been decreased from 53 years (Exhibit B-1, Table 7-2) to 40 years as per the opinion of Gannett Fleming (refer to Exhibit B-4, Attachment 9.2.3(a), provided in response to BCUC IR 1.9.2.3(a)).

8 Reference: Exhibit B-4, BCUC 1.10.1 and BCUC 1.10.4 (pages 56 & 59)

8.1 Please confirm whether the Kootenay Long Term Facilities Strategy and the original estimated cost of $16.4 M addressed: a) moving the BCC and b) the Castle District Office end-of-life.

<u>Response:</u>

Confirmed. The original KOC Project cost estimate completed in 2012 included relocation of the BCC and the Castlegar District Office Network Services group. Requirements for the Castlegar District Office were removed from the scope of the KOC Project and the cost estimate included in the KOC Project Application was revised to account for the scope change, promulgation of the 2012 BC Building Code, changes due to MRS requirements and market cost increases.

9 Reference: Exhibit B-4, BCUC 1.11.1 and BCUC 1.11.1.1 (page 65)

Exhibit B-6, CEC 1.14.1 (page 27)

9.1 Please confirm whether the $132,000 per year for current Generation Overhead cost is net of (i.e. after) recoveries, similar to the expected quoted cost of $29,000. If not, what is the current cost net of recoveries?

<u>Response:</u>

FBC is providing the responses to BCOAPO IR 2.9.1 through 2.9.5 in this response.

Not confirmed. The $132 thousand amount is the total facilities operating cost for the South Slocan Generation Site as it exists today before recoveries. In 2015, $103 thousand will be recovered based on the Generation absorption costing model. The cost allocation model pools all related support costs such as fleet, facility and management costs and distributes these costs on the basis of productive hours worked at the FBC owned and operated hydroelectric plants. After the KOC is in operation there will still be approximately $30 thousand of facility costs at the South Slocan Generation Site for maintaining access, infrastructure and maintenance of lands; however, because the Major Maintenance and other operations support groups which conduct third party work are relocating to the KOC, none of the $30 thousand will be included in the cost pool for determining recoveries from third parties.

The net $40 thousand referred to in the response to BCUC IR 1.11.1 is the net cost after Recoveries of Generation (see Line 1 of the Table below) related to the KOC. It does not relate to changes in facility costs at South Slocan. The response to CEC IR 1.14.1 provided a breakdown of the Kootenay Operations Centre by activity and as such, site specific information on South Slocan O&M was not included. Further, O&M changes related to South Slocan were not included in Table 5-1 and Table 5-2 as the incremental net O&M sums to, effectively, a zero change as shown in the table below.

The following table summarizes the changes in the O&M at KOC and at South Slocan.

Line No.		$000's O&M	$000's Recoveries	$000's Net
1	Generation allocation of KOC incremental costs	$ 190	$ (150)	$ 40
2	Current facilities costs at South Slocan	(132)	103	(29)
3	Facilities cost remaining at South Slocan	30	-	30
4	Net change at South Slocan	(102)	103	1
5	Subtotal	88	(47)	41
6	Increased Generation Travel	30	-	30
7	Total Incremental Cost	$ 118	$ (47)	$ 71

The changes in the O&M at South Slocan, effectively, result in a zero change, and consequently there is no update required to the response to BCUC IR 1.1.3.

9.2 Also, what are the current and expected Generation Overhead costs at the South Slocan Generation site, prior to any netting of recoveries?

Response:

Please refer to the response to BCOAPO IR 2.9.1.

9.3 Please clarify whether the $40,000 net O&M impact noted in BCUC 1.11.1 includes the reduction in Generation Overhead cost at the South Slocan Generation site described in BCUC 1.11.1.1.

Response:

Please refer to the response to BCOAPO IR 2.9.1.

9.4 The response to CEC 1.14.1 suggests that the $295,000 forecast for KOC Operating costs does not include any offset to account for the lower Generation Overhead costs at the South Slocan Generation site. Please indicate where and how these reduced costs at the South Slocan Generation site are accounted for in Tables 5-1 and 5-2 of the Application.

Response:

Please refer to the response to BCOAPO IR 2.9.1.

9.5 Please provide a revised response to BCUC 1.1.3, which separates the $295,000 in KOC Operating Costs (and more specifically the $190,000 related to Generation) as between the gross O&M cost of the new KOC and the O&M savings associated with the relocation of staff/activities from their existing locations (per BCUC 1.11.1.1). Alternatively, if the relocation O&M savings (e.g. the reduced Generation Overhead costs at South Slocan) are not included in the response to BCUC1.1.3, please revise the response so as to include these savings.

Response:

Please refer to the response to BCOAPO IR 2.9.1.

10 Reference: Exhibit B-4, BCUC 1.12.4 (page 70)

10.1 Is the profit margin attributed to third party service included in the $150,000 increase in Generation recoveries?

Response:

No, the $150 thousand in Generation recoveries is exclusive of profit margin. The appropriate transfer pricing profit margin (for non-regulated business) or management fees (for regulated business) is applied to the total invoiced cost of providing service, which includes the $150 thousand recoveries. The transfer price or management fee is therefore in addition to the $150 thousand recovery.

10.2 Is the profit margin associated with third party services affected at all by the $150,000 increase in Generation recoveries?

Response:

Please refer to the response to BCOAPO IR 2.10.1.

11 Reference: Exhibit B-4, BCUC 1.13.1.1 and 1.13.3 (pages 72-74)

11.1 Does the recovery of costs from third parties for services provided by the regulated business include any recovery of the fixed costs (e.g. depreciation and carrying costs) for the facilities (such as the existing South Slocan facilities and the planned new KOC facilities) where the FortisBC staff providing the services are located? If not, why not?

Response:

Please refer to the response to ICG IR 2.4.1.

12 Reference: Exhibit B-6, CEC 1.14.5 (page 29)

12.1 Please confirm that while customers will receive 50% of any savings in O&M as a result of the project, they will pay for 100% of the increase in fixed costs (i.e. depreciation and carrying costs) associated with the project.

<u>Response:</u>

Under the terms of the PBR Plan, variances in base O&M expense and a portion of financing on variations in base capital expenditures are shared with customers. If a CPCN is granted for this Project and the KOC building is in-service in 2017, customers will share 50% of the net incremental O&M impact of the Project during the PBR period, i.e. until 2019. Thereafter, after returning to cost of service ratemaking, 100% of the impacts of the Project will be embedded in customer rates. Customers will pay for the depreciation expense and carrying cost in 2018 and 2019. Customers will also receive 100% of the income tax expense reduction after the project is in service as a result of the CCA claimed.

Please also refer to the response to BCUC IR 2.2.4 and Attachment 2.4F which provides an update to the response to BCUC IR 1.10.8 and discusses the incremental O&M associated with the Project.

13 Reference: Exhibit B-7, ICG 1.9.1 (page 14)

Exhibit B-4, BCUC 1.1.1 & 1.1.2 (pages 4& 7)

13.1 The response to ICG 1.9.1 states that four positions will be relocated from the Trail Office Building. However, the responses to BCUC 1.1.1 and 1.1.2 show a reduction in Trail Office staff of only three. Please reconcile.

Response:

As noted in the response to ICG IR 1.9.1, it is expected that four positions will be relocated from the Trail Office Building to the proposed KOC. The tables included in the responses to BCUC IRs 1.1.1 and 1.1.2 reflect an overall change of three positions at the Trail Office Building because one position, which is not part of the Generation Department but is currently located at the Generation Facilities, will relocate to the Trail Office Building.

13.2 The response to ICG 1.9.1 states that 38 positions will be relocated from the Warfield Complex. However, the responses to BCUC 1.1.1 and 1.1.2 show a reduction in Warfield staff of from 59 to 42 for change of only 17. Please reconcile.

Response:

This response is being filed confidentially as it contains information relating to the Company's assets, including Critical Assets. FBC believes that there is a reasonable expectation that the release of such information could potentially jeopardize the safety and security of the Company's system or assets.