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November 2, 2007

Via Email
Original via mail

Ms. Erica M. Hamilton
Commission Secretary
BC Utilities Commission
Sixth Floor, 900 Howe Street, Box 250
Vancouver, BC V6Z 2N3

Dear Ms. Hamilton:

Re: An Application for a CPCN for the Distribution Substation Automation Program

Please find enclosed FortisBC Inc.'s response to Information Request No. 1 from BCOAPO et al and Mr. Alan Wait.

Sincerely,

David Bennett
Vice President, Regulatory Affairs
and General Counsel

cc: Registered Intervenors

1 Reference: August 28, 2007 Application ("The Application"), page 3, lines 4-8 and pages 26-29

Q1.1 Are technical losses all a function of system design?

A1.1 Technical losses are a function of system load, design (system impedance) and operating configuration.

Q1.2 Is the ability that the Program will provide to monitor individual distribution feeder loads (and subsequently move loads between feeders to optimize system performance) expected to reduce overall system losses? If so, is there an estimate of the potential savings?

A1.2 Monitoring individual distribution loads provides the data to evaluate optimal switching which would result in reduced overall system losses. However, without the current coincidental individual feeder load information to refine the models there is no means to estimate the potential savings.

2 Reference: The Application, page 7, lines 8-13 and page 37, lines 16-21

Q2.1 Please indicate what other utilities have installed similar automation systems; communication systems or informational databases.

A2.1 The protection, metering, communications and RTU hardware proposed by the Program is used by the majority of electric utilities in North America. As a local example, BC Hydro/BCTC installs essentially the same protection, metering and RTU hardware as FortisBC. BCTC also has a data historian server.

Q2.2 Has FortisBC directly contacted any of these utilities regarding their experience with these systems and databases? If so, please summarize the feedback received.

A2.2 FortisBC staff has discussed the application of these systems with counterparts at numerous other utilities. The nature of the conversations has been informal and extend over a lengthy period. These conversations have reiterated the many benefits listed in Section 4 of the Application that automation systems provide.

Please also see the response to BCUC IR1, Appendix A15.1, which contains a survey of North American utility investment in transmission and distribution automation.

Q2.3 Please indicate where on FortisBC's system such technology has been installed and for how long it has been in place.

A2.3 FortisBC has been using technology systems as described below:

System	First installed
Intelligent relaying (SEL relays)	1995
Power-quality monitoring devices (PML meters)	1994
SCADA RTU's (GE RTU's)	1999
Power-quality monitoring database (PML)	1996

These systems have been applied as standard packages with all recent distribution substation projects. Examples include: Cascade Substation (completed in 1999), Lambert Substation (completed in 2004), Waterford Substation (completed in 2006) and the Cottonwood Substation (completed in 2007).

Q2.4 Given that FortisBC already has similar equipment in place that has been successful in enabling the desired outcome, please explain why the current archiving server hardware and software are inadequate and new hardware and software are required.

A2.4 The current archiving server hardware and software only interfaces to power-quality meters. It is a very comprehensive system which is capable of collecting large amounts of detailed metering data such as voltage, amperage, load and energy readings; sag/swell disturbance information; waveform recordings; and individual harmonic readings. This results in huge amounts of data which is prohibitive to archive for long periods. In general, the existing system is not well suited to very long term storage and retrieval of data. As well, since the metering system is not capable of connecting to the FortisBC SCADA system (due to protocol incompatibilities), there is a large amount of data which is not currently accessible to general users.

The data historian hardware and software proposed as part of the Program would link to the metering and SCADA systems (as well as the Computerized Maintenance Management System in the future) and is complementary to them.

The data historian offers three significant benefits:

1. It supports multiple data acquisition protocols and is thus able to link to diverse systems such as the metering, SCADA and maintenance management systems.
2. It allows selective, long-term archiving of key information (primarily load readings) from either the metering or SCADA systems.
3. It provides a unified interface and repository for the data. Any FortisBC user would be able to query the archive and generate reports as needed.

Following is an excerpt from the specification of the historian software:

> *"The purpose of this subsystem is to store real-time and historical process values along with their respective qualities in a long term, online disk storage file system, while providing the means for users to access this data, display high-quality graphics, plot and trend this data, and import/export this data for offline analysis. The historian system must be designed to accommodate very large real-time and historical databases such that every process point is stored online for years in its original collected resolution. The historian compression must not, in any way, affect nor filter the data from its original resolution and sampled state. The historian system must provide for the ability to implement sophisticated performance-based calculations external to the SCADA system, and the results of these calculations must be stored in the historian database." Reference: Instep Software, LLC – "Typical Requirements for a Comprehensive Data Historian"*

3 Reference: The Application, pages 12-13; page 23; and pages 39-40
FortisBC Response to BCUC Staff IR #3.4

Q3.1 Please indicate the anticipated in-service dates for the new distribution stations that are not included in the scope of the current Application (page 12, lines 2-15).

A3.1 Following are the in-service dates for the listed substations:

a. Cottonwood (south of Nelson) – Q3 of 2007 (actual)
b. Arawana (Naramata) – Q4 of 2009 (estimated)
c. Kettle Valley (east of Rock Creek) – Q2 of 2008 (estimated)
d. Nk'Mip (east Osoyoos) – Q4 of 2007 (actual)

e. Big White (Big White Village) – Q4 of 2008 (estimated)
f. Ellison (north Kelowna) – Q4 of 2008 (estimated)
g. Black Mountain (east Kelowna) – Q1 of 2009 (estimated)
h. Ootischenia (east of Castlegar) – Q4 of 2008 (estimated)

Q3.2 Please indicate the anticipated retirement dates for the older substations that are not included in the program (page 12, lines 17-30).

A3.2 Listed below are the dates which the substations would no longer be used to supply the distribution system.

a. Naramata – Q4 of 2009 (estimated)
b. Wynndel – Q3 of 2007 (actual)
c. Rock Creek– Q3 of 2008 (estimated)
d. Midway – Q3 of 2008 (estimated)
e. Greenwood – Q4 of 2009 (estimated)
f. Paterson – Q4 of 2007 (estimated)
g. Whitewater– Q4 of 2007 (actual)
h. Ymir – Q3 of 2011 (estimated)

Q3.3 With respect to the response to BCUC Staff IR #3.4, does this mean that the full benefits of the program will <u>not</u> be achieved until the all the new substations are also in-service and the older substations have all been decommissioned/replaced? If not, why not?

A3.3 To gain maximum benefits from the Program it is necessary to have the systems described installed in all distribution substation locations. Since it is not possible to predict where outages or failures will occur, remote visibility should be extended to all substations to ensure that the FortisBC System Control Centre is aware of problems, no matter where they occur. The older stations listed in A3.2 will be retired before the end of the program.

Q3.4 If the response to part 3.3 is yes, are the benefits set out in Table 5 (page 23) those attributable to full scale implementation at all substations or the (partial) benefits from the actual program?

A3.4 The benefits listed in Table 5 are attributable to full scale implementation of the Program. However, it should be noted that even with a staged deployment of the proposed systems, that some of the benefits can be achieved immediately. It is on this basis that FortisBC has been installing the systems at all recently constructed substations.

Q3.5 Please confirm that the Revenue Requirement Analysis presented in Appendix 1 assumes the full program benefits are available starting in 2011 with the completion of the program. If the dates provided in response to 3.1 or 3.1 extend beyond 2011:

- **Please comment on the reasonableness of this assumption, and**
- **Please redo the Revenue Requirement Analysis, with the benefits starting upon full equipment installation at all substations.**

A3.5 Confirmed. Since the new stations will be completed and the older stations removed from service by the end of 2011, the original assumptions made in the NPV analysis are still valid and no revision is necessary.

4 Reference: The Application, page 12
FortisBC Response to BCUC Staff IR#3.4

Q4.1 Are there any benefits to be derived from installing the automation systems at the new substations (page 12, lines 7-15), if the proposed program does not proceed? If so, please indicate (both qualitatively and quantitatively) what they are.

A4.1 Even if the automation systems are not deployed at all locations, the stations that are equipped with the systems would gain the benefits listed in Section 4 of the Application. For example, there would be localized improvements in reliability and safety that would result from remote control and visibility. Localized load forecasting would also be improved by having accurate transformer and feeder historical loading information. The benefits would be proportional to the number of stations that had the required systems versus those that did not.

Q4.2 If the benefits of the Program are dependent upon full deployment of automation systems at all substations, why wasn't the NPV calculated based on the cost of installing new equipment at all substations, including the new substations listed on page 12? Please indicate why this wouldn't be a more appropriate basis on which to do the analysis.

A4.2 The localized benefits gained from the automation systems are significant and thus these systems are considered standard and included in all new substation project designs and estimates. Please also refer to the responses to Q3.4 and Q4.1.

5 Reference: The Application, Appendix I

Q5.1 Please indicate the basis for the discount rate of 10% used in the NPV analysis.

A5.1 The discount rate is based on a real discount rate of 8% plus inflation of 2%. FortisBC has used a real discount rate of 8% as a base case in evaluating its capital expenditures for a number of years.

6 Reference: FortisBC Response to BCUC Staff IR #5.1

Q6.1 Please confirm that under the current PBR plan that applies to FortisBC, O&M savings that result in a variance to after-tax return on equity are only shared (equally) between the Company and the rate payers to the extent the savings lead to an ROE that is 0.5 percentage points higher than the approved ROE.

A6.1 Under the current PBR ROE Sharing Mechanism, a 2% collar has been set around the allowed ROE whereby variances (adjusted for certain revenue and cost variances which flow through to customers) as a result of actual financial performance, positive or negative, will be shared equally between customers and the shareholder. There is no 0.5% threshold.

Q6.2 Based on FortisBC's current 2007 projected rate base and cost of capital, what level of annual O&M savings would produce a 0.5% variance in after-tax return on equity?

A6.2 Based on FortisBC's 2007 Approved Revenue Requirements of $209,480,000, O&M savings of approximately $1,050,000 would be required to produce a 0.5% variance in after-tax ROE. As stated in the response to Q6.1, all variances in after-tax ROE within a 2.0% range are shared equally between customers and the shareholder.

7 Reference: The Application, page 3, lines 10-12Appendix I

Q7.1 The Executive Summary indicates that the automated systems permit power transformer life to be more precisely measured over time. Please indicate where, in section 4, this particular benefit is discussed and valued.

A7.1 This benefit is discussed and valued in Section 4.9.d “Transformer Replacement.”

1. Reference BCUC IR A.2.1

Q1.1 Why if the server hardware lasts for only 5 years is it depreciated at 10.6% rather than 20%?

A1.1 The Company depreciates fixed assets by asset pool. For computer equipment, the FortisBC approved rate is 10.6%.

2. Ref. item 4.4

Q2.1 Confirm that FortisBC expects the line loss reduction of 1 to 2% is from 9.5% to 8.5% or 7.5%. Does that figure include line losses in the wheeling of power by BC Transmission?

A2.1 FortisBC believes there is a potential of further reductions to system losses of 1-2% and this could mean a reduction from 9.5% to 8.5% or 7.5% if system improvements were made and load growth remained static. However, as system improvements reduce losses, system growth tends to increase losses; therefore, the net loss level is dependent on both factors. It is unlikely that system losses could be sustained at less than 8.5%.

The 9.5% loss level includes losses from wheeling of power by BCTC.

3. Ref. Table 5

Q3.1 Please show how average benefits of table 5, P.23 of $590,000 becomes the figures shown on line 56 of Appendix A.

A3.1 As discussed in Section 3.5 of the Application, the average value of the savings ($590,000) is allocated as 80% towards future capital reductions and 20% to operating cost reductions. Thus, $590,000 x 20% = $118,000. This is the figure shown on line 56 of Appendix A. This value is then escalated at 2% per year beyond 2011.

4. Ref. 4.9.d

Q4.1 Please show the calculation for a $2 mil transformer replacement that results in a $75,000/year cost to ratepayers.

A4.1 The requested information is provided below.

1	Transformer Acquisition		$	2,000,000			
2							
3	Mid Year Rate Base (year 1)		$	1,000,000			
4							
5		Capital Structure					
6	Cost of Debt	60%	$	600,000	6.43%	$	38,580
7	Cost of Equity	40%	$	400,000	9.19%		36,760
8	Tax on Equity				32.5%		17,699
9	Income Tax on Timing Difference				Line 20		(26,000)
10	Leased line costs (Estimate)						8,000
11	Depreciation				3.0%		-
12	Tax timing differences						
13	**Year 1 Revenue Requirement impact**					**$**	**75,039**
14							
15	Tax Timing Differences:						
16	CCA 1/2 year rule	8.0%				$	80,000
17	Depreciation	3.0%					-
18						$	80,000
19							
20	Income Tax on Timing Difference				32.5%	$	26,000

5. Ref. P.18, L.27&28

Q5.1 Please show the assumptions and calculations used for the savings in capital costs which represent some 80% of the expected savings. Which transformers would be expected to last longer and how much longer?

A5.1 In the case of the future capital cost savings, most of this savings is due to reduced labour costs during major outages. The rationale for the 80/20% allocation is explained in Section 3.5 of the application and further confirmed in the response to BCUC IR1 Q24.1.

The savings due to avoided transformer upgrades will be sporadic. However, as the system load continues to grow, more transformers will be reaching their nameplate capacity. The monitoring to be installed by this program will assist in determining if a transformer replacement can be deferred by permitting a limited amount of short-duration overloads. Transformers affected will depend on where the load growth is more rapid.