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November 27, 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 ("the Program")

Please find enclosed twenty copies of FortisBC Inc.'s ("FortisBC") response to BC Utilities Commission Information Request No. 2.

Further to Exhibit A-4, FortisBC will file Final Argument on Friday, November 30.

Sincerely,

David Bennett
Vice President, Regulatory Affairs
and General Counsel

cc: Registered Intervenors

29.0 Reference: Exhibit No. B-2, FortisBC Response to BCUC IR No. 1 dated October 12, 2007, A1.3, p. 2

"CMMS is FortisBC's Computerized Maintenance Management System that is used to track and schedule maintenance for all major equipment in the transmission and distribution system. The Application identified that CMMS could link into the station automation central database but did not suggest that this was a primary requirement of the Automation or CMMS projects at this time. The value of transferring data from the metering system to CMMS would be evaluated separately outside of this project. The automation Program will collect data considered important to the maintenance program but will not integrate with CMMS as part of this project."

Q29.1 Please provide an estimate of the additional cost to link the station automation central database to the CMMS.

A29.1 The detailed estimates requested have not been developed as they are not within the present scope of the Automation Program. However, the cost to link the two systems would essentially be labour costs of approximately $40,000 to configure the database linkages. No significant additional hardware or software would be required.

Q29.2 Please provide a listing of benefits and their estimated costs of adding the link to the CMMS system.

A29.2 Please see the response to Q29.1 above.

30.0 Reference: Exhibit No. B-2, FortisBC Response to BCUC IR No. 1 dated October 12, 2007, A1.4, p. 2

Q30.1 Will the ability to develop user-defined queries be included in the software package cost or is it an additional extra?

A30.1 The ability to develop user-defined queries is included in the base software package price.

Q30.2 If there is an extra cost for this feature, please provide the estimated cost.

A30.2 Please see the response to Q30.1 above.

31.0 Reference: Exhibit No. B-2, FortisBC Response to BCUC IR No. 1 dated October 12, 2007, A3.3, p. 5

"FortisBC is currently only upgrading obsolete metering at legacy substations under Station Sustaining capital projects. This involves the partial upgrade of two or three stations per year. In addition to this, protection and communications upgrades would need to be added to the sustaining budget. If the Application is not approved, it is expected that the current practice would be revised to include this additional work. At the present pace, it could take 15 years or more to complete these upgrades. The full benefit that the Program would provide would not be available until that time."

Q31.1 If the application is not approved, would FortisBC please estimate the partial benefit that would be achieved per year over the 15 years?

A31.1 As discussed in the responses to BCUC IR1 Q3.3 and Q3.4, generally only metering upgrades are carried out under the current sustaining capital budgets. Assuming that the sustaining program budget was increased to allow the installation of the additional required systems (such as relaying, RTU and communications installations), the benefits achieved would be proportional to the number of stations that had the required systems versus those that did not.

Note that it is difficult to precisely quantify the benefits that a single installation contributes to the overall Program. Since every substation is different and tends to have different automation requirements (i.e. load monitoring to determine if upgrades are required or remote control to reduce crew downtime) it is somewhat simplistic say that completing a single station will provide 1/28 of the benefits of the total Program (given that there are 28 stations included in the Program).

32.0 Reference: Exhibit No. B-2, FortisBC Response to BCUC IR No. 1 dated October 12, 2007, A3.5, p. 6

As the expected life of the proposed field equipment is 15 to 20 years (A2.2) and the server is five years and the software is suspect but probably five to ten years maximum, then at about 15 years into the future, FortisBC would be looking at changing and/or updating all the proposed equipment due to end of life.

Q32.1 Would FortisBC agree with the above, that suggests doing nothing now, will not necessarily result in higher costs in the future?

A32.1 FortisBC agrees that the scenario as presented above (a bulk replacement of the equipment after 15 years) may not necessarily result in higher equipment costs in the future; however, that is not the same as doing nothing now. If the start of this program was delayed by only a few years then the devices deployed at that time may be different from those deployed today. This may result in higher costs due to multiple and different designs as well as training requirements and spare stock for newer, different devices. Refer also to the response to BCUC IR1 Q3.5.

Q32.2 Would FortisBC agree that the technology changes within the next three to five years could result in a more advanced and more defined SCADA system being deployed at that time?

A32.2 FortisBC does agree that technology will continue to advance. However, the systems that are currently deployed meet all the requirements for today as well as having sufficient spare capacity to build in new functionality as required. The dilemma of delaying a technological installation in order to wait for a more advanced system is that there will always be a more advanced system "just a few years down the road".

In November 2007, FortisBC upgraded its aging SCADA servers as previously approved by the Commission in the FortisBC 2007 Capital Expenditure Plan under the General Plant (Information Systems) – "System Control SCADA Upgrade". The new FortisBC SCADA system is fully modern and has sufficient capacity to last well into the future.

Q32.3 As cyber-security standards are still being developed, would FortisBC considered it prudent to wait three to five more years before implementing this program?

A32.3 FortisBC has long been aware of the risks posed by cyber infrastructure and has implemented security measures starting with the initial installations. Some measures include: SCADA controlled security switches, virtual private network ("VPN") and firewall installations, intrusion alarming and password protection.

Since FortisBC already follows the intent of the NERC CIP standards it is not felt that there is any additional benefit that would be gained by waiting for the formal adoption of the standards. Instead, the numerous benefits that the Program provides would be needlessly delayed.

33.0 Reference: Exhibit No. B-2, FortisBC Response to BCUC IR No. 1 dated October 12, 2007, A4.3, p. 7

"As described in response A4.2, FortisBC feels that the performance of the systems has already been well established. The financial performance of the Program, in terms of meeting construction cost

estimates, would be made available to the Commission for review, if necessary. Note that this review would not include any cost benefits obtained from implementing the program. The only way to accurately measure the cost savings from the Program would be to analyze a selection of outages once the systems have been in place for a number of years."

Q33.1 What does FortisBC propose as a benchmark to measure the benefits of this program?

A33.1 FortisBC has considered a number of possible measures to determine the overall effectiveness of the Program. Some of these are:

- Direct reliability improvements (i.e. reduction in SAIDI/CAIDI)
- Reduction of travel costs (reduced crew vehicle usage)
- Safety improvements (timely notification of critical alarms)
- Improved operating efficiency (reduced recloser tagging costs)
- Identification of system losses

The Company feels that all of the above aspects will be positively impacted by automation. However, in some cases it is difficult to confirm that the Program either did or did not have an effect as each of the above items are stochastic and have many confounding variables. Each area is further discussed as follows:

1. Direct reliability improvements

Clearly, the Program will result in a reduction in outage durations for many customers. This is due to the fact that, at the present time, there are 17 distribution substations that have no remote visibility from the FortisBC SCC. As a result, outages must first be reported to the call centre for the system dispatchers to become aware of an outage. Appropriate crews are then dispatched to patrol the area and determine the scope of the outage. Once the problem is located and repaired, the crews must then travel back to the station to re-energize the feeder. If instead the system dispatchers had remote visibility to alert them of a feeder outage a number of different outcomes could occur:

- The SCC dispatcher could remotely close ("test") the feeder to determine if the problem was transient. If the feeder did not trip again the outage would end at that point.
- If the feeder tripped again crews could be immediately dispatched without having to wait for customer calls.
- When the fault is repaired the line crews could request the SCC to remotely close the feeder to restore the customers.

Each of these would contribute to reducing customer outage durations (especially given that most of the stations are in rural/remote areas). Thus, one measure could be to look for a reduction in outage durations.

The difficulty in quantifying this reliability benefit is that there are many other factors that affect feeder outage durations. Some examples are:

- Weather – in any given year there will be greater or fewer storms than predicted by the past averages. Some storms could also be localized and reduce reliability in some areas of the system whereas other areas could enjoy better than average reliability.
- System improvements – infrastructure upgrades such as pole and conductor replacement will provide local improvements in reliability compared to historical averages.
- Crew availability – depending on the location and scope of outages the travel time to repair faults could be significant.

Each of the above will produce random variations from year-to-year and will either appear to reduce or enhance the benefit provided by the Program.

Thus, while an overall improvement in system reliability is expected, the Company feels that it is not possible to judge the effectiveness of the Program solely by year-over-year comparison of reliability statistics.

2. Reduction of travel costs (reduced crew vehicle usage)

As with the previous item, crew travel is expected to be reduced by the Program. This is because workers will not have to travel between the substation and repair locations to perform switching. As well, travel to substations will not be required to turn off automatic reclosers when issuing "Guarantee of Non-Reclose" ("GNR") permits to other crews.

Similar to the previous issue however, tracking travel distance is problematic. Depending on the nature and scope of outages different amounts of travel are always required. Diligent recording and logging of vehicle odometers would be required and these readings would have to be manually entered into a database for future analysis. Thus, FortisBC does not feel that this would be an appropriate measure.

3. Safety improvements (timely notification of critical alarms)

Another possible measure is to determine how many high priority alarms were resolved more quickly by the advanced indication that the Program would provide. For example, rather than waiting for a month end cycle to determine that a station battery charger or trip coil has failed, remote indication would provide an immediate annunciation of the alarm to the FortisBC SCC.

Generally, it is not possible to determine how much advance notice of the alarm was provided because without the automation systems it is impossible to know when the initial failure occurred. As well, depending on the performance of the substation systems there will be greater or fewer numbers of equipment failures in any given location. The Automation Program will not be able to directly influence the number of failures that occur, only the response time to resolve them.

However, notwithstanding the previous discussion, it would be possible for FortisBC to provide a year-end report to the Commission listing significant substation alarms (if any) that occurred at substations included in the Program. This report would provide a summary of the event(s) and describe the expected improvement in response time that resulted.

4. Improved operating efficiency (reduced recloser tagging costs)

By allowing the FortisBC SCC to remotely enable and disable automatic reclosers, it is expected that there will be a reduction in labour costs associated with line work and brushing. This could be tracked by totaling and reporting the number of remotely-operated GNRs that are issued in a given year at the substation locations included in the Program.

As well, existing data exists for comparison purposes hence it would not be necessary to delay the Program to acquire baseline data. It should be noted that another utility (Newfoundland Power) successfully used the reduction in recloser tagging costs as the prime justification for their substation automation program.

5. Identification of system losses

As described in the response to Q34.2 below, the Program, in combination with a future Advanced Metering Infrastructure project, would allow identification of transmission and distribution system losses. The Company would be able to track and report system loss trends on a per-line and per-feeder basis.

In summary, the Company would be able to report on three areas of expected quantifiable benefits:

1. A summary report of substation alarms, their outcome and response time;
2. A report of the number of GNR permits issued by remote-control;
3. A system loss analysis report.

Q33.2 Currently, does FortisBC have the cost-to-restore the outages over the last five years and would five years of data be sufficient to provide a benchmark for this program?

A33.2 No, currently FortisBC does not specifically track the cost-to-restore outages. Please also refer to the response to BCUC IR1 Q24.1 in which it has been indicated that: *"FortisBC Inc. does not specifically track statistics on capital and operating expenditures related to forced outages."*

It is difficult to specify absolutely at the present moment whether or not five years of data would be sufficient to provide a benchmark for this program. However, such database is expected to identify an emerging trend as a result of the Automation Program which will then be able to define the data sufficiency / insufficiency as a benchmark for this program.

Q33.3 What additional performance issues would FortisBC encounter by delaying the program until sufficient benchmark data can be established and performance reported on an annual basis; and how long would this take to develop this benchmark data?

A33.3 While it is not expected that system performance would be expected to suffer if the Program was delayed, the numerous benefits listed in the application would also not be achieved. Refer also to the response to Q34.2 below.

Q33.4 Does FortisBC propose any other performance based targets that could be used to monitor the effectiveness of this program?

A33.4 Please see the response to Q33.1 above.

34.0 Reference: Exhibit No. B-2, FortisBC Response to BCUC IR No. 1 dated October 12, 2007, A7.3, p. 13

"FortisBC is currently in discussions with a utility industry security consultant (N-Dimension Solutions) to develop a more formal plan and mitigation measures for substation communications assets."

Q34.1 Would FortisBC please provide an estimated completion date for the above mentioned formal plan and mitigation measures?

A34.1 The discussions that are taking place with the consultant are to ensure that FortisBC is fully aware of all potential security issues related to SCADA communications. Developing the formal plan will mainly be a process of documenting the de-facto standards that FortisBC already applies. The plan should be completed by Q2 of 2008. If any capital upgrades are required to improve security, these will be identified in a future Capital Expenditure Plan filing.

Q34.2 Would FortisBC consider it prudent to delay the program until the results of a more formal plan and mitigation measures for substation communications assets are available? If not, why not?

A34.2 No. The Company believes it would be useful to reiterate the Program justification and how it fits into the longer term picture for the benefit of Intervenors and the Commission.

Introduction

As has been previously stated, the Distribution Substation Automation Program (the "Program") includes the installation of automated systems in distribution substations to gather and analyze data so that decisions can be made more quickly and effectively to reduce operational costs, and prevent and aid in the restoration of power outages. The Program will enable remote operating and automated load and quality metering of all substations in the system thus improving reliability and power quality for customers. Finally, public and employee safety risk along with equipment damage risk will be reduced by providing immediate indication of critical substation alarms.

The following discussion provides further clarification of four areas of the Program, specifically, the financial impact, linkage to other Company systems, the benefits associated with stakeholder requests from recent regulatory proceedings, consistency with the current BC Energy Plan and Government policy.

1. Financial Impact

In Table 5 and Section 3.5 of the Application, the Program identified annual cost savings of approximately $590,000 which results in a low rate impact of 0.05% to customers. These savings consist of conservative and quantifiable benefits that could be attributed directly to the Program. It should be noted that, of the twelve benefits identified in Table 5, four were assigned monetary values. The remaining benefits represented other areas that could result in cost savings, but at the time of filing it was not deemed appropriate to assign a value to these categories. If the estimated annual cost saving is increased to $830,000, then both the Program NPV and rate impact go to zero. Thus, if an incremental cost savings of only $240,000 per year can be quantified, then the net impact to the customer is zero.

By far, the largest opportunity yet to be attributed to the Program is with respect to the measurement and confirmation of current losses and the identification of future system loss reductions. This benefit was excluded from the financial analysis as the Company did not expect to have all the information required to accurately measure and detect distribution losses (which typically represent 50-60% of overall system losses). This was because the Program only proposes the installation of metering at the substation level. To accurately measure distribution losses it is necessary to also have complete information at the end-point or customer level. This difference between the energy leaving each substation feeder and the sum of the connected customer load would provide an accurate measure of losses for each feeder. At the time of filing it was not clear that this end-point metering would be in place and thus this benefit could not be tracked. However, since that time it is apparent from stated Government policy that automated customer metering of some form will be required in the near future.

The Application estimated that each 1.0% (absolute) loss reduction represents potentially $2.4 million in annual savings to customers for which no credit was applied to the NPV analysis of the current Application. Over recent years, the Company has continually reported reductions in system losses that have resulted in over $2.0 million of reduced annual power supply costs (to the benefit of the customer). If the Program is able to identify projects that result in a loss savings of only 0.1% per year, then the additional savings (approximately $240,000) would result in the program NPV going to zero (as described above). Loss reductions beyond 0.1% identified by the Program would have a further positive financial benefit for the customer. Since a reduction of losses by 0.1% is conservative, the Company has recalculated the NPV on the basis of assuming an annual savings of $790,000 compared to the previous value of $590,000. The revised NPV calculation is attached as Appendix 34.2.

Put another way, the metering component of the Program would provide one more reference point to enable the Company to determine if distribution system upgrades of the some 100 plus system distribution feeders would further reduce the system losses and thus power supply costs for a positive financial benefit to the customer. This benefit is greatly enhanced with Advanced Metering Infrastructure (AMI) for which the Company intends to file a CPCN application. The AMI project has a similar implementation plan, and as identified in Section 4 below, is expected to be required by the provincial government in the near future. It is important to note that neither the Program nor AMI by itself can provide the information to accurately assess system losses at the distribution feeder level. However, if both systems are in place (i.e. the distribution metering at the substation and AMI real-time metering at the end customer) then actual losses can be measured on both an almost instantaneous and annual basis. These losses could then be regularly tracked at the distribution feeder level. Neither project by itself will reduce losses; rather, they will provide valuable information to assess if system upgrade projects are warranted to capture these losses for the benefit of the customer.

2. Linkage to Other Company Systems

As described above, the Company intends to file a CPCN application for AMI with the communications technology either being Power-Line Carrier or Radio Frequency. In addition to the benefits expected from a system loss reduction perspective, there are also potential communication synergies that could reduce the capital cost of the AMI project dependent on the communication medium chosen.

Additionally, the data collection software to be installed will use "open protocols" for flexibility to allow it to be linked to other corporate databases and systems. In terms of providing information to other FortisBC systems, there are potential synergies to be gained by linking the Program to the following:

- Real-time outage reporting system
- Dispatch tools
- Reliability monitoring system
- Power-quality metering system
- SCADA system
- Computerized Maintenance Management System (CMMS)
- Advanced Metering Infrastructure (AMI)

Some of the above systems and tools are not currently used by FortisBC, but many other utilities are implementing them today. The Company will also be evaluating the benefits to be gained from installing these systems; the Program would provide one more source of information to obtain maximum benefits from these other systems.

3. Regulatory Proceeding Requests

Through information requests associated with recent substation CPCN Application, such as the Big White, East Osoyoos (Nk'Mip) , and Ootischenia projects, and the Company's 2008 Revenue Requirements Application (2008 RRA), the Company believes there is an expectation to improve the quality and type of information that it provides to aid in decision making. It is apparent that stakeholders and the Commission are requesting this additional information which the Company is generally unable to provide without the systems to be installed by the Program.

In almost all CPCN Applications since 2005 that involved the construction of a new substation, the Commission has requested annual load profile data for the local area. The Company has been unable to provide this information in the absence of modern substation metering. Since it is the legacy substations that are becoming more likely to require upgrades or replacement due to load growth, it is important to proactively install this metering at older substations so that accurate and optimal planning and regulatory decisions can be made in the future.

During the Company's 2008 RRA, it became apparent that the Commission is also becoming more interested in reactive power ("var") management to ensure that the costs of remediation measures are minimized and fairly allocated to the appropriate parties. The Program would directly support this initiative by providing a complete load and var profile of each feeder in the FortisBC system. This data could be analyzed to determine which feeders have less than ideal power factor and hence require infrastructure upgrades or customer power factor correction. A more focused analysis could then be made to determine if specific customers need to install reactive compensation equipment.

During the same proceeding, both the Commission and intervenors challenged the Company's system loss calculation and had high and increasing expectations of reducing system losses to ensure an efficient system thus minimizing power supply costs to customers.

In the absence of the Program and the associated information that will be obtained, these improvements are either not available or significantly limited in scope.

4. Consistency with BC Energy Plan and Government Policy

Although not specifically identified and quantified in the Application, the basic metering and automation planned under the Program provides the building block and foundation for the evolution of the system to support a number of initiatives referenced in the BC Energy Plan and recent addresses by the Premier of BC. The BC Energy Plan describes Major Policy Actions related to environmental leadership, energy conservation and energy efficiency. The proposed Program provides valuable information and directly supports these policy actions.

In his September address at the Union of BC Municipalities Annual Convention, the Premier identified the Government's intent to "legally require the province to reduce greenhouse gas emissions by 33 per cent below current levels by 2020." In the same speech, he also provided direction for BC Hydro to increase technology with the installation of Smart Meters and that the manual read meters would be replaced with these new meters. Another direction for BC Hydro/BCTC is to "install a new modern, smart electricity grid that will allow us to take full advantage of the information to help you save money." What is implied is that information will save energy and shift consumption from peak times thereby minimizing or reducing costs for the end customer. As previously mentioned, a 1% saving in energy (or system losses) equates to a potential annual saving of $2.4 million. This Program as contemplated implements the first phase of technology that can be leveraged further to support these provincial goals.

The Government has a strong commitment to energy efficiency and has set ambitious targets to acquire 50% of incremental resource needs through conservation by 2020. A portion of this goal can be met through loss reductions throughout the transmission and distribution systems. The Government has been in discussions with FortisBC looking for their input and support of this goal from a provincial perspective. Given the age of the FortisBC distribution system, there are opportunities for system upgrades to reduce losses and create a more energy efficient system in support of this provincial goal. Distribution metering at the substation level provides one component of information necessary for this analysis. A full analysis of loss reduction becomes possible with both distribution metering as proposed in this Program along with the Advanced Metering Infrastructure project.

Additionally, the Program is consistent with the goal of the BC Energy Plan to implement temperature monitoring of power transformers. By providing detailed load and temperature information for all distribution substations, optimal operational and planning decisions can be made. As discussed in the Application, it may be possible to defer capital expenditures by permitting safe short-duration transformer overload. The same flexibility will also extend to real-time operations: by providing the System Control Centre with instantaneous transformer temperature and load readings, the operators will be able to make better decisions when faced with peak time overloads. It is difficult to accurately quantify the financial or reliability savings from any avoided outages, however there will be a clear benefit to the customer in terms of system reliability.

Environmental leadership within the BC Energy Plan focuses on a reduction in greenhouse gases. The Application quantified a financial saving for remote operation based on a reduction in travel time and field visits by avoiding manual switching and tagging, but did not mention or quantify the environmental impact associated with this activity. The Program assumes that on an annual basis 1,800 manually-applied "Guarantee of Non Reclose" permits could be eliminated. The elimination of the associated travel time of between 900 and 1,800 hours would effectively eliminate one half to one full-time use of a vehicle along with a reduction of the associated greenhouse gases and environmental footprint on an annual basis.

Summary

Deferral of the program is inconsistent with both the Premier's stated goal of having a "smart grid" concept in place by 2012.

The Program has the following benefits:

- Reduces operating and capital costs,
- Reduces the duration of customer outages,
- Improves safety,
- Provides a detailed load and reactive power profiles for all substations and feeders,
- Allows focused reduction of system losses,
- Supports the BC Energy Plan,
- Enhances the electrical system by supporting the "smart electricity grid" concept.

These benefits are projected to result in a zero or positive rate impact for the customer. In addition, the Program provides more complete, accurate and timely information to stakeholders, the Commission and the Company on which to base decisions for the benefit of customers.

35.0 Reference: Exhibit No. B-2, FortisBC Response to BCUC IR No. 1 dated

October 12, 2007, A7.5, p. 14

"Application of the NERC Reliability Standards (including the CIP Cyber Security Standards) is not currently mandatory in British Columbia. FortisBC is working with other utilities in British Columbia to determine how these standards should be implemented within the BC regulatory framework."

Q35.1 Would FortisBC consider it prudent to delay the program until the results of how these standards should be implemented within the BC regulatory framework are available, required and understood? If not, why not?

A35.1 Please see the response to Q32.2 above.

36.0 Reference: Exhibit No. B-2, FortisBC Response to BCUC IR No. 1 dated October 12, 2007, A8.2, p. 15

"The Joe Rich Substation is not listed as it was identified as a specific issue and is currently being upgraded under a previously approved 2007 Communications Sustaining capital project."

Q36.1 What is the total current value for communications and automation protection and communications rehabilitation in the previously approved 2007 Communications Sustaining capital project?

A36.1 Please find the requested data in the table below:

	COMMUNICATION PROJECTS 2007	2007-APPROVED BUDGETARY LIMITS					
		Unloaded Cost	AFUDC	Capitalized Overhead	Direct Overhead	Loaded Total	Cost of Removal
1.0	**COMMUNICATION GROWTH**						
1.1	Dist Sub Automation - 2007	1,649	110	131	109	1,999	0
1.2	Trail-Oliver Hi Cap Comm. (Kettle Valley Proj.)	1,180	108	94	78	1,459	0
	TOTAL COMMUNICATION GROWTH	**2,829**	**218**	**224**	**187**	**3,458**	**0**
2.0	**COMMUNICATION SUSTAINING**						
2.1	Harmonic Remediation	85	0	7	6	97	0
2.2	Protection Upgrades	816	0	65	54	935	40
2.3	Fault Locating	128	0	10	8	147	0
2.4	Communication Upgrades	265	0	21	18	304	40
	TOTAL COMMUNICATION SUSTAINING	**1,294**	**0**	**103**	**86**	**1,482**	**80**

Q36.2 What is the total current value for communications and automation protection and communications rehabilitation in the proposed 2008 Communications Sustaining capital project?

A36.2 Please find the requested data in the table below:

	COMMUNICATION PROJECTS 2008	2008-APPROVED BUDGETARY LIMITS					
		Unloaded Cost	AFUDC	Capitalized Overhead	Direct Overhead	Loaded Total	Cost of Removal
1.0	**COMMUNICATION GROWTH**						
1.2	Dist Sub Automation - 2008	1,663	60	156	121	2,000	0
	TOTAL COMMUNICATION GROWTH	**1,663**	**60**	**156**	**121**	**2,000**	**0**
2.0	**COMMUNICATION SUSTAINING**						
2.1	Harmonic Remediation	87	0	8	6	101	0
2.2	Protection Upgrades	620	0	58	45	723	40
2.3	Fault Locating	132	0	12	10	154	0
2.4	Communication Upgrades	94	0	9	7	110	10
	TOTAL COMMUNICATION SUSTAINING	**933**	**0**	**88**	**68**	**1,088**	**50**

Q36.3 Would FortisBC confirm that there is no overlap between this program and the approved 2007 and proposed 2008 Communications Sustaining capital project requirements?

A36.3 Confirmed. There is no overlap.

37.0 Reference: Exhibit No. B-2, FortisBC Response to BCUC IR No. 1 dated October 12, 2007, A11.1 to A11.5, pp. 17-19

Q37.1 As the CMMS is not planned to communicate to the SCADA system, how does FortisBC record the meter readings now and how will FortisBC record the meter readings after the proposed program implementation?

A37.1 Monthly readings are currently entered into the CMMS manually. Once the data historian server is in place and operational, the two systems could be linked to automatically exchange the required data. However, this linkage would not be within the scope of the Automation Program.

Q37.2 As the CMMS is not planned to communicate to the SCADA system, how does FortisBC generate work orders and notify staff of unusual conditions now and how will FortisBC generate work orders and notify staff of unusual conditions after the proposed program implementation?

A37.2 The CMMS program generates work orders based on standard maintenance cycles adjusted in conjunction with condition assessment information, equipment test results and available operational information. The Automation Program is not intended at this time to generate notifications or work orders via the CMMS platform.

Q37.3 What is the estimated cost to provide these features that are not considered to be a primary requirement for the automation project and what is the cost and value of integration with the CMMS that will be evaluated at a future time?

A37.3 There has been no benefit/cost evaluation done for integration with CMMS, so the requested estimate is not available. This investigation will be carried out as part of the CMMS implementation.

38.0 Reference: Exhibit No. B-2, FortisBC Response to BCUC IR No. 1 dated October 12, 2007, A18.3, p. 31

Q38.1 Does FortisBC consider the link of the CMMS and SCADA as a benefit to the maintenance planning group that could have significant paybacks?

A38.1 In general, establishing links between databases is beneficial as it permits the exchange of data that may not be available otherwise. It can also reduce the collection of redundant information by multiple systems. However, the determination of the benefits to the CMMS is outside the scope of this Application.

39.0 Reference: Exhibit No. B-2, FortisBC Response to BCUC IR No. 1 dated October 12, 2007, A15.1, p. 22

"In the case of substation automation, utilities have begun prioritizing their substation requirements, installing IEDs in newly constructed and rebuilt substations first before moving on to other high priority locations. Our analysts report that transmission substations have been cited by utility personnel as taking priority over distribution substations, undoubtedly to support new requirements for upgrading network interconnect monitoring and switching functions." (Appendix A15.1, p. 7)

"Distribution automation projects remain the smallest category of reported projects." (Appendix A15.1, p. 7)

Q39.1 Would FortisBC please separate the costs so that one can distinguish between transmission and distribution substations?

A39.1 The study in Appendix A15.1 does not provide a specific breakdown of the expenditures for distribution versus transmission substations. Note that FortisBC has substantially completed the automation of the Company's transmission stations and thus the proposed Program is in line with the paragraph cited above.

It should also be clarified that "distribution automation" as cited from Appendix A15.1 page 7 ("the smallest category") is referring to automation of field distribution devices located outside of the substation fence. This is not the type of automation that is being proposed in this application.

Q39.2 As the application of the NERC Reliability Standards (including the CIP Cyber Security Standards) is not currently mandatory in British Columbia, does FortisBC believe that there is a need to meet pressures from NERC and FERC to improve network reliability and strengthen utility network interconnects at this time?

A39.2 FortisBC has already substantially completed the automation of the Company's transmission stations and thus the proposed Program is not being driven by interconnection reliability issues.

40.0 Reference: Exhibit No. B-2, FortisBC Response to BCUC IR No. 1 dated October 12, 2007, A19.1, p. 31

"The ability to reconfigure circuits does depend somewhat on manually operated devices located outside of the substation fence. Upgrading these devices for remote operation is not currently within the scope of

this program."

Q40.1 Would FortisBC please elaborate on the above statement?

Q40.1.1 What are these devices that need to be upgraded?

A40.1.1 The type of devices referred to in response A19.1 are distribution feeder manual switching devices located in the field. Typical examples include:

- Gang-operated load break ("GOLB") switches
- Padmount switching cubicles or vacuum fault interrupters ("VFI")
- Distribution circuit reclosers

Q40.1.2 What is the estimated total cost for this upgrade?

A40.1.2 Cost estimates for remote control of field devices have not been developed. Costs will vary depending on the whether the device is already provisioned for electrical operation and on the type of communications equipment required.

Q40.1.3 Are these transmission devices or substation devices?

A40.1.3 As discussed in response A40.1.1, the devices cited are distribution field devices.

Q40.2 If FortisBC has not included these devices in the scope of this program, how did FortisBC plan on obtaining funding for their upgrade?

A40.2 The costs and benefits of extending remote control to distribution field devices would be identified in a future Capital Expenditure Plan filing.

41.0 Reference: Exhibit No. B-2, FortisBC Response to BCUC IR No. 1 dated October 12, 2007, A25.2, p. 39

"As discussed in section 4.5 of the Application, the Program will provide advanced indication by providing real-time indication of alarms

to the FortisBC System Control Centre. Rather than waiting until a month-end cycle check to determine the presence of critical alarm, immediate action can be taken to correct the problem."

Q41.1 Please confirm that FortisBC does not use a common alarm at the substation to confirm the presence of a critical alarm.

A41.1 Confirmed – FortisBC present practice is to provide detailed individual alarms to the System Control Centre

42.0 Reference: Exhibit No. B-2, FortisBC Response to BCUC IR No. 1 dated October 12, 2007, Q26.8, p. 43

"The Application indicates that FortisBC total system losses are estimated to be 9.5 percent: this situation would suggest that by installing substation automation equipments there may be a reduction in total system losses."

Q42.1 Would FortisBC please explain how this program will reduce system losses and how much of a reduction would be expected from the implementation of this program and the estimated value of this reduction?

A42.1 Referring to a similar question from the BCOAPO, IR1 Q1.2, 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 or end-point customer information to refine the models there is no means to estimate the potential savings. Refer also to the response to BCUC IR2 Q34.2 above.

43.0 Reference: Exhibit No. B-2, FortisBC Response to BCUC IR No. 1 dated October 12, 2007, A27.1, p. 44

"No option or risk analysis has been performed for the Program. The only alternative is the "do-nothing" option which has been rejected due

to the large number of benefits that would be achievable by implementing the Program."

Q43.1 As no option or risk analysis has been performed for the Program, does FortisBC propose that the cost of doing nothing is zero? If not, why not?

A43.1 FortisBC is of the opinion that the opportunity cost of the known but unquantified benefits would be forgone if the Program was not implemented. Please refer to the response to Q34.2.

44.0 Reference: Exhibit No. B-2, Responses to Commission Information Requests No. 1, Q2.1, p. 3 and Q26.5, p. 42

"The expected lifespan of the server hardware is five years."

Q44.1 Please re-run Appendix A26.1 to include server hardware replacements every five years in accordance with the response in A2.1. Please also include in the re-run Appendix A26.1 the replacement assets from Appendix A26.5.

A44.1 Please see Appendix A44.1 attached.

45.0 Reference: Exhibit No. B-2, Responses to Commission Information Requests No. 1, Q26.2, p. 40

Q45.1 Please provide copy of July 2007 Consensus Economics forecast that reflects the numbers presented in Forecast 2008.

A45.1 The July 2007 Consensus Economics forecast cannot be provided due to copyright. The report is available to subscribers at www.consensuseconomics.com. FortisBC's return on capital will be approved as part of its 2008 Revenue Requirements Application.

FortisBC Inc.
Capital Project Analysis
Distribution Substation Automation Program

Option:1

Line No.		Year: Reference	1 Dec-07	2 Dec-08	3 Dec-09	4 Dec-10	5 Dec-11	6 Dec-12	7 Dec-13	8 Dec-14	9 Dec-15	10 Dec-16	11 Dec-17	12 Dec-18
	Summary													
	Revenue Requirements													
1	Operating Expense (Incremental)	Line 60	0	10	25	45	(92)	(94)	(96)	(98)	(100)	(102)	(104)	(106)
2	Depreciation Expense	Line 65	0	0	32	119	204	294	345	306	267	227	186	145
3	Carrying Costs	Line 72	0	20	92	194	291	360	344	271	201	132	65	0
4	Income Tax	Line 85	0	(32)	(124)	(209)	(249)	(230)	(94)	55	151	210	244	260
5	Total Revenue Requirement for Project		0	(2)	25	149	153	331	500	535	519	467	392	299
6	**Net Present Value of Revenue Requirement**	10.00%	0											
	Rate Impact													
7	**Forecast Revenue Requirements**		209,300	219,817	240,023	255,139	272,208	287,690	293,400	299,300	305,300	311,400	317,600	324,000
8	Rate Impact		0.00%	0.00%	0.01%	0.06%	0.06%	0.12%	0.17%	0.18%	0.17%	0.15%	0.12%	0.09%
	Annual Incremental Rate Impact over previous year		0.00%	0.00%	0.01%	0.05%	0.00%	0.06%	0.06%	0.01%	-0.01%	-0.02%	-0.03%	-0.03%
9	**NPV of Project / Total Revenue Requirements**		0.00%											
	Regulatory Assumptions													
10	Equity Component		40.00%	40.00%	40.00%	40.00%	40.00%	40.00%	40.00%	40.00%	40.00%	40.00%	40.00%	40.00%
11	Debt Component		60.00%	60.00%	60.00%	60.00%	60.00%	60.00%	60.00%	60.00%	60.00%	60.00%	60.00%	60.00%
12	Equity Return		8.77%	9.02%	9.02%	9.02%	9.02%	9.02%	9.02%	9.02%	9.02%	9.02%	9.02%	9.02%
13	Debt Return		6.40%	6.43%	6.43%	6.43%	6.43%	6.43%	6.43%	6.43%	6.43%	6.43%	6.43%	6.43%
	Capital Cost													
14	Bell Terminal			24									0	0
15	Castlegar			345										
16	Duck Lake			131										
17	Fruitvale			42										
18	Glenmore			125										
19	Hollywood			375										
20	Keremeos			54										
21	Summerland			89										
22	Beaver Park				152									
23	Blueberry				140									
24	OK Mission				383									
25	Osoyoos				122									
26	Playmor				183									
27	Saucier				37									
28	Valhalla				91									
29	Westminster				140									
30	Christina Lake					180								
31	Glenmerry					186								
32	Hedley					348								
33	Salmo					155								
34	Trout Creek					223								
35	West Bench					286								
36	Huth						190							
37	Passmore						139							
38	Sexsmith						272							
39	Slocan City						95							
40	Stoney Creek						291							
41	Tarrys						348							
42	Data Server hardware & software			140	33	0	0							
43	Initial engineering, estimating, procurement		462											
44	Capital Cost Subtotal		462	1,324	1,281	1,378	1,336							
45	Contingency (10%)		46	132	128	138	134							
46	AFUDC		18	0	0	0	0							
47	Cumulative Project Cost Subtotal		526	1,983	3,392	4,908	6,378							
48	Estimated Annual Capital Savings						(629)	(641)	(654)	(667)	(681)	(694)	(708)	(722)
49	Total Cash Outlay in Year		**526**	**1,456**	**1,409**	**1,516**	**841**	**(641)**	**(654)**	**(667)**	**(681)**	**(694)**	**(708)**	**(722)**
50	Cumulative Cash Outlay		526	1,983	3,392	4,908	5,749	5,108	4,454	3,786	3,106	2,412	1,704	981
51			0	0	0	0	0	0	0	0	0	0	0	0
52	Cumulative Project Cost		526	1,983	3,392	4,908	5,749	5,108	4,454	3,786	3,106	2,412	1,704	981
53	Additions to Plant		0	526	1,456	1,409	1,516	841	(641)	(654)	(667)	(681)	(694)	(708)
54	Cumulative Additions to Plant		0	526	1,983	3,392	4,908	5,749	5,108	4,454	3,786	3,106	2,412	1,704
55	CWIP		526	1,456	1,936	3,499	4,233	4,267	5,095	4,441	3,773	3,092	2,398	1,689
56	Total Annual Savings (80% Capital 20% Operating)						786	802	818	834	851	868	885	903
	Annual Operating Costs / (Savings)													
57	Estimated Cost Savings						(157)	(160)	(164)	(167)	(170)	(174)	(177)	(181)
58	Communications - Leased Line Costs			10	20	40	60	61	62	64	65	66	68	69
59	Software Maintenance Costs				5	5	5	5	5	6	6	6	6	6
60	Total Incremental Operating Costs (Savings) (Forecast inflation rate 2%)		0	10	25	45	(92)	(94)	(96)	(98)	(100)	(102)	(104)	(106)
	Depreciation Expense													
61	Opening Cash Outlay		0	0	526	1,983	3,392	4,908	5,749	5,108	4,454	3,786	3,106	2,412
62	Additions in Year	Line 53	0	526	1,456	1,409	1,516	841	(641)	(654)	(667)	(681)	(694)	(708)
63	Cumulative Total		0	526	1,983	3,392	4,908	5,749	5,108	4,454	3,786	3,106	2,412	1,704
64	Depreciation Rate - composite average		6.00%	6.00%	6.00%	6.00%	6.00%	6.00%	6.00%	6.00%	6.00%	6.00%	6.00%	6.00%
65	Depreciation Expense		0	0	32	119	204	294	345	306	267	227	186	145
	Net Book Value													
66	Gross Property	Line 54	0	526	1,983	3,392	4,908	5,749	5,108	4,454	3,786	3,106	2,412	1,704
67	Accumulated Depreciation		0	0	(32)	(151)	(354)	(649)	(993)	(1,300)	(1,567)	(1,794)	(1,981)	(2,125)
68	Net Book Value		0	526	1,951	3,241	4,554	5,100	4,114	3,154	2,219	1,311	431	(422)
	Carrying Costs on Average NBV													
69	Return on Equity		0	9	45	94	141	174	166	131	97	64	31	0
70	Interest Expense		0	10	48	100	150	186	178	140	104	68	34	0
71	AFUDC		0	0	0	0	0	0	0	0	0	0	0	0
72	**Total Carrying Costs**		0	20	92	194	291	360	344	271	201	132	65	0
	Income Tax Expense													
73	Combined Income Tax Rate		33.00%	31.50%	31.00%	31.00%	30.50%	30.50%	30.50%	30.50%	30.50%	30.50%	30.50%	30.50%
	Income Tax on Equity Return													
74	Return on Equity	Line 69	0	9	45	94	141	174	166	131	97	64	31	0
75	Gross up for revenue (Return / (1- tax rate)		0	14	65	136	202	251	239	189	139	92	45	0
76	Less: Income tax on Equity Return		0	4	20	42	62	76	73	58	43	28	14	0
77	Net Income (equal return on equity)		0	9	45	94	141	174	166	131	97	64	31	0
	Income Tax on Timing Differences													
78	Depreciation Expense		0	0	32	119	204	294	345	306	267	227	186	145
79	Less: Capital Cost Allowance	Line 92	0	79	353	677	912	992	725	313	21	(188)	(338)	(447)
80	Total Timing Differences		0	(79)	(321)	(558)	(709)	(698)	(380)	(6)	246	415	524	591
81	Income Tax on Timing Differences		0	(25)	(100)	(173)	(216)	(213)	(116)	(2)	75	127	160	180
82	Before Tax Revenue Requirement [=Line 52/(1-tax)]		0	(36)	(144)	(251)	(311)	(306)	(167)	(3)	108	182	230	259
85	**Total Income Tax**	Lines 76 + 82	0	(32)	(124)	(209)	(249)	(230)	(94)	55	151	210	244	260
	Capital Cost Allowance													
86	Opening Balance - UCC		0	0	447	1,551	2,284	2,887	2,736	1,370	403	(285)	(778)	(1,135)
87	Additions to Plant		0	526	1,456	1,409	1,516	841	(641)	(654)	(667)	(681)	(694)	(708)
88	Subtotal UCC		0	526	1,904	2,960	3,800	3,728	2,095	716	(264)	(966)	(1,472)	(1,843)
89	Capital Cost Allowance Rate		30.00%	30.00%	30.00%	30.00%	30.00%	30.00%	30.00%	30.00%	30.00%	30.00%	30.00%	30.00%
90	CCA on Opening Balance		0	0	134	465	685	866	821	411	121	(86)	(233)	(340)
91	CCA on Capital Expenditures (1/2 yr rule)		0	79	218	211	227	126	(96)	(98)	(100)	(102)	(104)	(106)
92	Total CCA		0	79	353	677	912	992	725	313	21	(188)	(338)	(447)
93	Ending Balance UCC		0	447	1,551	2,284	2,887	2,736	1,370	403	(285)	(778)	(1,135)	(1,396)

A44.1a) Includes server hardware replacements every five years in accordance with the response in A2.1.

FortisBC Inc.
Capital Project Analysis
Distribution Substation Automation Program

Option:1

Line No.		Year: Reference	1 Dec-07	2 Dec-08	3 Dec-09	4 Dec-10	5 Dec-11	6 Dec-12	7 Dec-13	8 Dec-14
	Summary									
	Revenue Requirements									
1	Operating Expense (Incremental)	Line 59	0	10	25	45	(53)	(54)	(55)	(56)
2	Depreciation Expense	Line 64	0	0	32	119	204	294	354	325
3	Carrying Costs	Line 71	0	20	94	197	295	372	367	306
4	Income Tax	Line 85	0	(33)	(130)	(208)	(248)	(237)	(112)	26
5	Total Revenue Requirement for Project		0	(3)	21	153	198	375	554	602
6	**Net Present Value of Revenue Requirement**	10.00%	1,234							
	Rate Impact									
7	**Forecast Revenue Requirements**		209,300	226,200	244,100	249,000	254,000	259,100	264,300	269,600
8	Rate Impact		0.00%	0.00%	0.01%	0.06%	0.08%	0.14%	0.21%	0.22%
	Annual Incremental Rate Impact over previous year		0.00%	0.00%	0.01%	0.05%	0.02%	0.07%	0.06%	0.01%
9	**NPV of Project / Total Revenue Requirements**		0.05%							
	Regulatory Assumptions									
10	Equity Component		40.00%	40.00%	40.00%	40.00%	40.00%	40.00%	40.00%	40.00%
11	Debt Component		60.00%	60.00%	60.00%	60.00%	60.00%	60.00%	60.00%	60.00%
12	Equity Return		8.77%	9.19%	9.19%	9.19%	9.19%	9.19%	9.19%	9.19%
13	Debt Return		6.40%	6.50%	6.50%	6.50%	6.50%	6.50%	6.50%	6.50%
	Capital Cost									
14	Bell Terminal			24						
15	Castlegar			345						
16	Duck Lake			131						
17	Fruitvale			42						
18	Glenmore			125						
19	Hollywood			375						
20	Keremeos			54						
21	Summerland			89						
22	Beaver Park				152					
23	Blueberry				140					
24	OK Mission				383					
25	Osoyoos				122					
26	Playmor				183					
27	Saucier				37					
28	Valhalla				91					
29	Westminster				140					
30	Christina Lake					180				
31	Glenmerry					186				
32	Hedley					348				
33	Salmo					155				
34	Trout Creek					223				
35	West Bench					286				
36	Huth						190			
37	Passmore						139			
38	Sexsmith						272			
39	Slocan City						95			
40	Stoney Creek						291			
41	Tarrys						348			
42	Data Server hardware & software			140	33	0	0		54	13
43	Initial engineering, estimating, procurement		462							
44	Capital Cost Subtotal		462	1,324	1,281	1,378	1,336	0	54	13
45	Contingency (10%)		46	132	128	138	134	0	5	1
46	AFUDC		18	0	0	0	0	0	0	0
47	Cumulative Project Cost Subtotal		526	1,983	3,392	4,908	6,378	6,378	6,437	6,451
48	Estimated Annual Capital Savings						(472)	(481)	(491)	(501)
49	Total Cash Outlay in Year		**526**	**1,456**	**1,409**	**1,516**	**998**	**(481)**	**(432)**	**(487)**
50	Cumulative Cash Outlay		526	1,983	3,392	4,908	5,906	5,424	4,993	4,506
51			0	0	0	0	0	0	0	0
52	Cumulative Project Cost		526	1,983	3,392	4,908	5,906	5,424	4,993	4,506
53	Additions to Plant		0	526	1,456	1,409	1,516	998	(481)	(432)
54	Cumulative Additions to Plant		0	526	1,983	3,392	4,908	5,906	5,424	4,993
55	CWIP		526	1,456	1,936	3,499	4,390	4,427	5,474	4,938
	Annual Operating Costs / (Savings)									
56	Estimated Cost Savings						(118)	(120)	(123)	(125)
57	Communications - Leased Line Costs			10	20	40	60	61	62	64
58	Software Maintenance Costs				5	5	5	5	5	6
59	Total Incremental Operating Costs (Savings)		0	10	25	45	(53)	(54)	(55)	(56)
	(Forecast inflation rate 2%)									
	Depreciation Expense									
60	Opening Cash Outlay		0	0	526	1,983	3,392	4,908	5,906	5,424
61	Additions in Year	Line 53	0	526	1,456	1,409	1,516	998	(481)	(432)
62	Cumulative Total		0	526	1,983	3,392	4,908	5,906	5,424	4,993
63	Depreciation Rate - composite average		6.00%	6.00%	6.00%	6.00%	6.00%	6.00%	6.00%	6.00%
64	Depreciation Expense		0	0	32	119	204	294	354	325
	Net Book Value									
65	Gross Property	Line 54	0	526	1,983	3,392	4,908	5,906	5,424	4,993
66	Accumulated Depreciation		0	0	(32)	(151)	(354)	(649)	(1,003)	(1,328)
67	Net Book Value		0	526	1,951	3,241	4,554	5,257	4,421	3,664
	Carrying Costs on Average NBV									
68	Return on Equity		0	10	46	95	143	180	178	149
69	Interest Expense		0	10	48	101	152	191	189	158
70	AFUDC		0	0	0	0	0	0	0	0
71	**Total Carrying Costs**		0	20	94	197	295	372	367	306
	Income Tax Expense									
72	Combined Income Tax Rate		33.00%	32.50%	32.00%	31.00%	30.50%	30.50%	30.50%	30.50%
	Income Tax on Equity Return									
73	Return on Equity	Line 68	0	10	46	95	143	180	178	149
74	Gross up for revenue (Return / (1- tax rate)		0	14	67	138	206	259	256	214
75	Less: Income tax on Equity Return		0	5	21	43	63	79	78	65
76	Net Income (equal return on equity)		0	10	46	95	143	180	178	149
	Income Tax on Timing Differences									
77	Depreciation Expense		0	0	32	119	204	294	354	325
78	Less: Capital Cost Allowance	Line 92	0	79	353	677	912	1,016	789	415
79	Total Timing Differences		0	(79)	(321)	(558)	(709)	(721)	(434)	(90)
80	Income Tax on Timing Differences		0	(26)	(103)	(173)	(216)	(220)	(132)	(27)
81	Before Tax Revenue Requirement [=Line 52/(1-tax)]		0	(38)	(151)	(251)	(311)	(317)	(191)	(39)
85	**Total Income Tax**	Lines 75 + 81	0	(33)	(130)	(208)	(248)	(237)	(112)	26
	Capital Cost Allowance									
86	Opening Balance - UCC		0	0	447	1,551	2,284	2,887	2,869	1,599
87	Additions to Plant		0	526	1,456	1,409	1,516	998	(481)	(432)
88	Subtotal UCC		0	526	1,904	2,960	3,800	3,885	2,388	1,168
89	Capital Cost Allowance Rate		30.00%	30.00%	30.00%	30.00%	30.00%	30.00%	30.00%	30.00%
90	CCA on Opening Balance		0	0	134	465	685	866	861	480
91	CCA on Capital Expenditures (1/2 yr rule)		0	79	218	211	227	150	(72)	(65)
92	Total CCA		0	79	353	677	912	1,016	789	415
93	Ending Balance UCC		0	447	1,551	2,284	2,887	2,869	1,599	753

FortisBC Inc.
Capital Project Analysis
Distribution Substation Automation Program

Option:1

Line No.		Year: Reference	9 Dec-15	10 Dec-16	11 Dec-17	12 Dec-18	13 Dec-19	14 Dec-20	15 Dec-21	16 Dec-22	17 Dec-23	18 Dec-24	19 Dec-25	20 Dec-26
	Summary													
	Revenue Requirements													
1	Operating Expense (Incremental)	Line 59	(57)	(58)	(59)	(61)	(62)	(63)	(64)	(66)	(67)	(68)	(70)	(71)
2	Depreciation Expense	Line 64	300	270	240	208	177	(57)	(537)	(564)	(575)	(587)	(526)	(593)
3	Carrying Costs	Line 71	248	188	130	73	20	(23)	(42)	(43)	(44)	(42)	(42)	(46)
4	Income Tax	Line 85	117	178	214	233	236	145	(50)	(45)	(37)	(36)	(5)	(26)
5	Total Revenue Requirement for Project		607	578	524	454	372	3	(693)	(718)	(724)	(733)	(643)	(736)
6	**Net Present Value of Revenue Requirement**	10.00%												
	Rate Impact													
7	**Forecast Revenue Requirements**		275,000	280,500	286,100	291,800	297,600	303,600	309,700	315,900	322,200	328,600	335,200	341,900
8	Rate Impact		0.22%	0.21%	0.18%	0.16%	0.12%	0.00%	-0.22%	-0.23%	-0.22%	-0.22%	-0.19%	-0.22%
	Annual Incremental Rate Impact over previous year		0.00%	-0.01%	-0.02%	-0.03%	-0.03%	-0.12%	-0.22%	0.00%	0.00%	0.00%	0.03%	-0.02%
9	**NPV of Project / Total Revenue Requirements**													
	Regulatory Assumptions													
10	Equity Component		40.00%	40.00%	40.00%	40.00%	40.00%	40.00%	40.00%	40.00%	40.00%	40.00%	40.00%	40.00%
11	Debt Component		60.00%	60.00%	60.00%	60.00%	60.00%	60.00%	60.00%	60.00%	60.00%	60.00%	60.00%	60.00%
12	Equity Return		9.19%	9.19%	9.19%	9.19%	9.19%	9.19%	9.19%	9.19%	9.19%	9.19%	9.19%	9.19%
13	Debt Return		6.50%	6.50%	6.50%	6.50%	6.50%	6.50%	6.50%	6.50%	6.50%	6.50%	6.50%	6.50%
	Capital Cost													
14	Bell Terminal				0	0	0	0	0	0	0	0	0	0
15	Castlegar													
16	Duck Lake													
17	Fruitvale													
18	Glenmore													
19	Hollywood													
20	Keremeos													
21	Summerland													
22	Beaver Park													
23	Blueberry													
24	OK Mission													
25	Osoyoos													
26	Playmor													
27	Saucier													
28	Valhalla													
29	Westminster													
30	Christina Lake													
31	Glenmerry													
32	Hedley													
33	Salmo													
34	Trout Creek													
35	West Bench													
36	Huth													
37	Passmore													
38	Sexsmith													
39	Slocan City													
40	Stoney Creek													
41	Tarrys													
42	Data Server hardware & software		0	0	0	60	14	0	0	0	66	16	0	0
43	Initial engineering, estimating, procurement													
44	Capital Cost Subtotal		0	0	0	60	14	0	0	0	66	16	0	0
45	Contingency (10%)		0	0	0	6	1	0	0	0	7	2	0	0
46	AFUDC		0	0	0	0	0	0	0	0	0	0	0	0
47	Cumulative Project Cost Subtotal		6,451	6,451	6,451	6,517	6,533	6,533	6,533	6,533	6,605	6,623	6,623	6,623
48	Estimated Annual Capital Savings		(511)	(521)	(532)	(542)	(553)	(564)	(575)	(587)	(599)	(611)	(623)	(635)
49	Total Cash Outlay in Year		**(511)**	**(521)**	**(532)**	**(476)**	**(537)**	**(564)**	**(575)**	**(587)**	**(526)**	**(593)**	**(623)**	**(635)**
50	Cumulative Cash Outlay		3,995	3,474	2,942	2,466	1,929	1,365	789	202	(324)	(917)	(1,540)	(2,175)
51			0	0	0	0	0	0	0	0	0	0	0	0
52	Cumulative Project Cost		3,995	3,474	2,942	2,466	1,929	1,365	789	202	(324)	(917)	(1,540)	(2,175)
53	Additions to Plant		(487)	(511)	(521)	(532)	(476)	(537)	(564)	(575)	(587)	(526)	(593)	(623)
54	Cumulative Additions to Plant		4,506	3,995	3,474	2,942	2,466	1,929	1,365	789	202	(324)	(917)	(1,540)
55	CWIP		4,482	3,985	3,464	2,998	2,405	1,902	1,353	778	263	(391)	(947)	(1,552)
	Annual Operating Costs / (Savings)													
56	Estimated Cost Savings		(128)	(130)	(133)	(136)	(138)	(141)	(144)	(147)	(150)	(153)	(156)	(159)
57	Communications - Leased Line Costs		65	66	68	69	70	72	73	75	76	78	79	81
58	Software Maintenance Costs		6	6	6	6	6	6	6	6	7	7	7	7
59	Total Incremental Operating Costs (Savings)		(57)	(58)	(59)	(61)	(62)	(63)	(64)	(66)	(67)	(68)	(70)	(71)
	(Forecast inflation rate 2%)													
	Depreciation Expense													
60	Opening Cash Outlay		4,993	4,506	3,995	3,474	2,942	2,466	1,929	1,365	789	202	(324)	(917)
61	Additions in Year	Line 53	(487)	(511)	(521)	(532)	(476)	(537)	(564)	(575)	(587)	(526)	(593)	(623)
62	Cumulative Total		4,506	3,995	3,474	2,942	2,466	1,929	1,365	789	202	(324)	(917)	(1,540)
63	Depreciation Rate - composite average		6.00%	6.00%	6.00%	6.00%	6.00%	6.00%	6.00%	6.00%	6.00%	6.00%	6.00%	6.00%
64	Depreciation Expense		300	270	240	208	177	(57)	(537)	(564)	(575)	(587)	(526)	(593)
	Net Book Value													
65	Gross Property	Line 54	4,506	3,995	3,474	2,942	2,466	1,929	1,365	789	202	(324)	(917)	(1,540)
66	Accumulated Depreciation		(1,628)	(1,898)	(2,138)	(2,346)	(2,523)	(2,466)	(1,929)	(1,365)	(789)	(202)	324	917
67	Net Book Value		2,878	2,097	1,336	596	(57)	(537)	(564)	(575)	(587)	(526)	(593)	(623)
	Carrying Costs on Average NBV													
68	Return on Equity		120	91	63	36	10	(11)	(20)	(21)	(21)	(20)	(21)	(22)
69	Interest Expense		128	97	67	38	11	(12)	(21)	(22)	(23)	(22)	(22)	(24)
70	AFUDC		0	0	0	0	0	0	0	0	0	0	0	0
71	**Total Carrying Costs**		248	188	130	73	20	(23)	(42)	(43)	(44)	(42)	(42)	(46)
	Income Tax Expense													
72	Combined Income Tax Rate		30.50%	30.50%	30.50%	30.50%	30.50%	30.50%	30.50%	30.50%	30.50%	30.50%	30.50%	30.50%
	Income Tax on Equity Return													
73	Return on Equity	Line 68	120	91	63	36	10	(11)	(20)	(21)	(21)	(20)	(21)	(22)
74	Gross up for revenue (Return / (1- tax rate)		173	132	91	51	14	(16)	(29)	(30)	(31)	(29)	(30)	(32)
75	Less: Income tax on Equity Return		53	40	28	16	4	(5)	(9)	(9)	(9)	(9)	(9)	(10)
76	Net Income (equal return on equity)		120	91	63	36	10	(11)	(20)	(21)	(21)	(20)	(21)	(22)
	Income Tax on Timing Differences													
77	Depreciation Expense		300	270	240	208	177	(57)	(537)	(564)	(575)	(587)	(526)	(593)
78	Less: Capital Cost Allowance	Line 92	153	(43)	(185)	(287)	(352)	(399)	(444)	(482)	(512)	(525)	(535)	(557)
79	Total Timing Differences		147	313	424	496	529	342	(93)	(82)	(64)	(62)	9	(36)
80	Income Tax on Timing Differences		45	95	129	151	161	104	(28)	(25)	(19)	(19)	3	(11)
81	Before Tax Revenue Requirement [=Line 52/(1-tax)]		64	137	186	218	232	150	(41)	(36)	(28)	(27)	4	(16)
85	**Total Income Tax**	Lines 75 + 81	117	178	214	233	236	145	(50)	(45)	(37)	(36)	(5)	(26)
	Capital Cost Allowance													
86	Opening Balance - UCC		753	113	(355)	(692)	(936)	(1,060)	(1,199)	(1,319)	(1,412)	(1,487)	(1,488)	(1,546)
87	Additions to Plant		(487)	(511)	(521)	(532)	(476)	(537)	(564)	(575)	(587)	(526)	(593)	(623)
88	Subtotal UCC		266	(398)	(876)	(1,223)	(1,412)	(1,597)	(1,763)	(1,894)	(1,999)	(2,013)	(2,082)	(2,169)
89	Capital Cost Allowance Rate		30.00%	30.00%	30.00%	30.00%	30.00%	30.00%	30.00%	30.00%	30.00%	30.00%	30.00%	30.00%
90	CCA on Opening Balance		226	34	(107)	(207)	(281)	(318)	(360)	(396)	(424)	(446)	(446)	(464)
91	CCA on Capital Expenditures (1/2 yr rule)		(73)	(77)	(78)	(80)	(71)	(81)	(85)	(86)	(88)	(79)	(89)	(93)
92	Total CCA		153	(43)	(185)	(287)	(352)	(399)	(444)	(482)	(512)	(525)	(535)	(557)
93	Ending Balance UCC		113	(355)	(692)	(936)	(1,060)	(1,199)	(1,319)	(1,412)	(1,487)	(1,488)	(1,546)	(1,612)

A44.1b) Includes replacement assets from Appendix A26.5.

FortisBC Inc.
Capital Project Analysis
Distribution Substation Automation Program

Option:1

Line No.		Year: Reference	1 Dec-07	2 Dec-08	3 Dec-09	4 Dec-10	5 Dec-11	6 Dec-12	7 Dec-13	8 Dec-14
	Summary									
	Revenue Requirements									
1	Operating Expense (Incremental)	Line 59	0	10	25	45	(53)	(54)	(55)	(56)
2	Depreciation Expense	Line 64	0	32	119	204	294	383	383	386
3	Carrying Costs	Line 71	19	94	197	295	390	420	393	366
4	Income Tax	Line 85	(34)	(133)	(218)	(254)	(265)	(173)	(54)	29
5	Total Revenue Requirement for Project		(15)	3	123	290	367	575	667	726
6	**Net Present Value of Revenue Requirement**	10.00%	4,516							
	Rate Impact									
7	**Forecast Revenue Requirements**		209,300	226,200	244,100	249,000	254,000	259,100	264,300	269,600
8	Rate Impact		-0.01%	0.00%	0.05%	0.12%	0.14%	0.22%	0.25%	0.27%
	Annual Incremental Rate Impact over previous year		-0.01%	0.01%	0.05%	0.07%	0.03%	0.08%	0.03%	0.02%
9	**NPV of Project / Total Revenue Requirements**		0.18%							
	Regulatory Assumptions									
10	Equity Component		40.00%	40.00%	40.00%	40.00%	40.00%	40.00%	40.00%	40.00%
11	Debt Component		60.00%	60.00%	60.00%	60.00%	60.00%	60.00%	60.00%	60.00%
12	Equity Return		8.77%	9.19%	9.19%	9.19%	9.19%	9.19%	9.19%	9.19%
13	Debt Return		6.40%	6.50%	6.50%	6.50%	6.50%	6.50%	6.50%	6.50%
	Capital Cost									
14	Bell Terminal			24						
15	Castlegar			345						
16	Duck Lake			131						
17	Fruitvale			42						
18	Glenmore			125						
19	Hollywood			375						
20	Keremeos			54						
21	Summerland			89						
22	Beaver Park				152					
23	Blueberry				140					
24	OK Mission				383					
25	Osoyoos				122					
26	Playmor				183					
27	Saucier				37					
28	Valhalla				91					
29	Westminster				140					
30	Christina Lake					180				
31	Glenmerry					186				
32	Hedley					348				
33	Salmo					155				
34	Trout Creek					223				
35	West Bench					286				
36	Huth						190			
37	Passmore						139			
38	Sexsmith						272			
39	Slocan City						95			
40	Stoney Creek						291			
41	Tarrys						348			
42	Data Server hardware & software			140	33	0	0		54	13
43	Initial engineering, estimating, procurement		462							
44	Capital Cost Subtotal		462	1,324	1,281	1,378	1,336	0	54	13
45	Contingency (10%)		46	132	128	138	134	0	5	1
46	AFUDC		18	0	0	0	0	0	0	0
47	Cumulative Project Cost Substotal		526	1,983	3,392	4,908	6,378	6,378	6,437	6,451
48	Estimated Annual Capital Savings									
49	Total Cash Outlay in Year		**526**	**1,456**	**1,409**	**1,516**	**1,470**	**0**	**60**	**14**
50	Cumulative Cash Outlay		526	1,983	3,392	4,908	6,378	6,378	6,437	6,451
51			0	0	0	0	0	0	0	0
52	Cumulative Project Cost		526	1,983	3,392	4,908	6,378	6,378	6,437	6,451
53	Additions to Plant		526	1,456	1,409	1,516	1,470	0	60	14
54	Cummulative Additions to Plant		526	1,983	3,392	4,908	6,378	6,378	6,437	6,451
55	CWIP		0	526	1,983	3,392	4,908	6,378	6,378	6,437
	Annual Operating Costs / (Savings)									
56	Estimated Cost Savings						(118)	(120)	(123)	(125)
57	Communications - Leased Line Costs			10	20	40	60	61	62	64
58	Software Maintenance Costs				5	5	5	5	5	6
59	Total Incremental Operating Costs (Savings)		0	10	25	45	(53)	(54)	(55)	(56)
	(Forecast inflation rate 2%)									
	Depreciation Expense									
60	Opening Cash Outlay		0	526	1,983	3,392	4,908	6,378	6,378	6,437
61	Additions in Year	Line 53	526	1,456	1,409	1,516	1,470	0	60	14
62	Cumulative Total		526	1,983	3,392	4,908	6,378	6,378	6,437	6,451
63	Depreciation Rate - composite average		6.00%	6.00%	6.00%	6.00%	6.00%	6.00%	6.00%	6.00%
64	Depreciation Expense		0	32	119	204	294	383	383	386
	Net Book Value									
65	Gross Property	Line 54	526	1,983	3,392	4,908	6,378	6,378	6,437	6,451
66	Accumulated Depreciation		0	(32)	(151)	(354)	(649)	(1,031)	(1,414)	(1,800)
67	Net Book Value		526	1,951	3,241	4,554	5,729	5,347	5,023	4,651
	Carrying Costs on Average NBV									
68	Return on Equity		9	46	95	143	189	204	191	178
69	Interest Expense		10	48	101	152	201	216	202	189
70	AFUDC		0	0	0	0	0	0	0	0
71	**Total Carrying Costs**		19	94	197	295	390	420	393	366
	Income Tax Expense									
72	Combined Income Tax Rate		33.00%	32.50%	32.00%	31.00%	30.50%	30.50%	30.50%	30.50%
	Income Tax on Equity Return									
73	Return on Equity	Line 68	9	46	95	143	189	204	191	178
74	Gross up for revenue (Return / (1- tax rate)		14	67	140	208	272	293	274	256
75	Less: Income tax on Equity Return		5	22	45	64	83	89	84	78
76	Net Income (equal return on equity)		9	46	95	143	189	204	191	178
	Income Tax on Timing Differences									
77	Depreciation Expense		0	32	119	204	294	383	383	386
78	Less: Capital Cost Allowance	Line 92	79	353	677	912	1,087	981	696	498
79	Total Timing Differences		(79)	(321)	(558)	(709)	(792)	(598)	(313)	(112)
80	Income Tax on Timing Differences		(26)	(104)	(178)	(220)	(242)	(183)	(95)	(34)
81	Before Tax Revenue Requirement [=Line 52/(1-tax)]		(39)	(155)	(262)	(319)	(348)	(263)	(137)	(49)
85	**Total Income Tax**	Lines 75 + 81	(34)	(133)	(218)	(254)	(265)	(173)	(54)	29
	Capital Cost Allowance									
86	Opening Balance - UCC		0	447	1,551	2,284	2,887	3,270	2,289	1,653
87	Additions to Plant		526	1,456	1,409	1,516	1,470	0	60	14
88	Subtotal UCC		526	1,904	2,960	3,800	4,357	3,270	2,349	1,667
89	Capital Cost Allowance Rate		30.00%	30.00%	30.00%	30.00%	30.00%	30.00%	30.00%	30.00%
90	CCA on Opening Balance		0	134	465	685	866	981	687	496
91	CCA on Capital Expenditures (1/2 yr rule)		79	218	211	227	220	0	9	2
92	Total CCA		79	353	677	912	1,087	981	696	498
93	Ending Balance UCC		447	1,551	2,284	2,887	3,270	2,289	1,653	1,169

FortisBC Inc.
Capital Project Analysis
Distribution Substation Automation Program

Option:1

Line No.		Year: Reference	9 Dec-15	10 Dec-16	11 Dec-17	12 Dec-18	13 Dec-19	14 Dec-20	15 Dec-21	16 Dec-22	17 Dec-23	18 Dec-24	19 Dec-25	20 Dec-26
	Summary													
	Revenue Requirements													
1	Operating Expense (Incremental)	Line 59	(57)	(58)	(59)	(61)	(62)	(63)	(64)	(66)	(67)	(68)	(70)	(71)
2	Depreciation Expense	Line 64	387	387	387	420	458	497	534	534	534	538	539	539
3	Carrying Costs	Line 71	338	308	300	314	330	341	326	285	247	210	170	138
4	Income Tax	Line 85	88	128	122	95	77	72	110	159	187	205	219	213
5	Total Revenue Requirement for Project		756	765	750	768	803	847	905	913	902	886	859	819
6	**Net Present Value of Revenue Requirement**	10.00%												
	Rate Impact													
7	**Forecast Revenue Requirements**		275,000	280,500	286,100	291,800	297,600	303,600	309,700	315,900	322,200	328,600	335,200	341,900
8	Rate Impact		0.27%	0.27%	0.26%	0.26%	0.27%	0.28%	0.29%	0.29%	0.28%	0.27%	0.26%	0.24%
	Annual Incremental Rate Impact over previous year		0.01%	0.00%	-0.01%	0.00%	0.01%	0.01%	0.01%	0.00%	-0.01%	-0.01%	-0.01%	-0.02%
9	**NPV of Project / Total Revenue Requirements**													
	Regulatory Assumptions													
10	Equity Component		40.00%	40.00%	40.00%	40.00%	40.00%	40.00%	40.00%	40.00%	40.00%	40.00%	40.00%	40.00%
11	Debt Component		60.00%	60.00%	60.00%	60.00%	60.00%	60.00%	60.00%	60.00%	60.00%	60.00%	60.00%	60.00%
12	Equity Return		9.19%	9.19%	9.19%	9.19%	9.19%	9.19%	9.19%	9.19%	9.19%	9.19%	9.19%	9.19%
13	Debt Return		6.50%	6.50%	6.50%	6.50%	6.50%	6.50%	6.50%	6.50%	6.50%	6.50%	6.50%	6.50%
	Capital Cost													
14	Bell Terminal				10	0	0	0	0	0	0	0	0	4
15	Castlegar				144	0	0	0	0	0	0	0	0	60
16	Duck Lake				55	0	0	0	0	0	0	0	0	23
17	Fruitvale				17	0	0	0	0	0	0	0	0	7
18	Glenmore				52	0	0	0	0	0	0	0	0	22
19	Hollywood				157	0	0	0	0	0	0	0	0	66
20	Keremeos				22	0	0	0	0	0	0	0	0	9
21	Summerland				37	0	0	0	0	0	0	0	0	16
22	Beaver Park				0	64	0	0	0	0	0	0	0	0
23	Blueberry				0	59	0	0	0	0	0	0	0	0
24	OK Mission				0	160	0	0	0	0	0	0	0	0
25	Osoyoos				0	51	0	0	0	0	0	0	0	0
26	Playmor				0	76	0	0	0	0	0	0	0	0
27	Saucier				0	15	0	0	0	0	0	0	0	0
28	Valhalla				0	38	0	0	0	0	0	0	0	0
29	Westminster				0	59	0	0	0	0	0	0	0	0
30	Christina Lake				0	0	75	0	0	0	0	0	0	0
31	Glenmerry				0	0	78	0	0	0	0	0	0	0
32	Hedley				0	0	145	0	0	0	0	0	0	0
33	Salmo				0	0	65	0	0	0	0	0	0	0
34	Trout Creek				0	0	93	0	0	0	0	0	0	0
35	West Bench				0	0	119	0	0	0	0	0	0	0
36	Huth				0	0	0	79	0	0	0	0	0	0
37	Passmore				0	0	0	58	0	0	0	0	0	0
38	Sexsmith				0	0	0	114	0	0	0	0	0	0
39	Slocan City				0	0	0	40	0	0	0	0	0	0
40	Stoney Creek				0	0	0	122	0	0	0	0	0	0
41	Tarrys				0	0	0	146	0	0	0	0	0	0
42	Data Server hardware & software		0	0	0	60	14	0	0	0	66	16	0	0
43	Initial engineering, estimating, procurement				0	0	0	0	0	0	0	0	0	0
44	Capital Cost Subtotal		0	0	495	582	591	559	0	0	66	16	0	207
45	Contingency (10%)		0	0	50	58	59	56	0	0	7	2	0	21
46	AFUDC		0	0	0	0	0	0	0	0	0	0	0	0
47	Cumulative Project Cost Substotal		6,451	6,451	6,996	7,636	8,286	8,901	8,901	8,901	8,973	8,990	8,990	9,218
48	Estimated Annual Capital Savings													
49	Total Cash Outlay in Year		**0**	**0**	**545**	**640**	**650**	**615**	**0**	**0**	**73**	**17**	**0**	**228**
50	Cumulative Cash Outlay		6,451	6,451	6,996	7,636	8,286	8,901	8,901	8,901	8,973	8,990	8,990	9,218
51			0	0	0	0	0	0	0	0	0	0	0	0
52	Cumulative Project Cost		6,451	6,451	6,996	7,636	8,286	8,901	8,901	8,901	8,973	8,990	8,990	9,218
53	Additions to Plant		0	0	545	640	650	615	0	0	73	17	0	228
54	Cummulative Additions to Plant		6,451	6,451	6,996	7,636	8,286	8,901	8,901	8,901	8,973	8,990	8,990	9,218
55	CWIP		6,451	6,451	6,451	6,996	7,636	8,286	8,901	8,901	8,901	8,973	8,990	8,990
	Annual Operating Costs / (Savings)													
56	Estimated Cost Savings		(128)	(130)	(133)	(136)	(138)	(141)	(144)	(147)	(150)	(153)	(156)	(159)
57	Communications - Leased Line Costs		65	66	68	69	70	72	73	75	76	78	79	81
58	Software Maintenance Costs		6	6	6	6	6	6	6	6	7	7	7	7
59	Total Incremental Operating Costs (Savings)		(57)	(58)	(59)	(61)	(62)	(63)	(64)	(66)	(67)	(68)	(70)	(71)
	(Forecast inflation rate 2%)													
	Depreciation Expense													
60	Opening Cash Outlay		6,451	6,451	6,451	6,996	7,636	8,286	8,901	8,901	8,901	8,973	8,990	8,990
61	Additions in Year	Line 53	0	0	545	640	650	615	0	0	73	17	0	228
62	Cumulative Total		6,451	6,451	6,996	7,636	8,286	8,901	8,901	8,901	8,973	8,990	8,990	9,218
63	Depreciation Rate - composite average		6.00%	6.00%	6.00%	6.00%	6.00%	6.00%	6.00%	6.00%	6.00%	6.00%	6.00%	6.00%
64	Depreciation Expense		387	387	387	420	458	497	534	534	534	538	539	539
	Net Book Value													
65	Gross Property	Line 54	6,451	6,451	6,996	7,636	8,286	8,901	8,901	8,901	8,973	8,990	8,990	9,218
66	Accumulated Depreciation		(2,187)	(2,574)	(2,961)	(3,381)	(3,839)	(4,336)	(4,871)	(5,405)	(5,939)	(6,477)	(7,016)	(7,556)
67	Net Book Value		4,264	3,877	4,035	4,255	4,447	4,564	4,030	3,496	3,035	2,513	1,974	1,662
	Carrying Costs on Average NBV													
68	Return on Equity		164	150	145	152	160	166	158	138	120	102	82	67
69	Interest Expense		174	159	154	162	170	176	168	147	127	108	88	71
70	AFUDC		0	0	0	0	0	0	0	0	0	0	0	0
71	**Total Carrying Costs**		338	308	300	314	330	341	326	285	247	210	170	138
	Income Tax Expense													
72	Combined Income Tax Rate		30.50%	30.50%	30.50%	30.50%	30.50%	30.50%	30.50%	30.50%	30.50%	30.50%	30.50%	30.50%
	Income Tax on Equity Return													
73	Return on Equity	Line 68	164	150	145	152	160	166	158	138	120	102	82	67
74	Gross up for revenue (Return / (1- tax rate)		236	215	209	219	230	238	227	199	173	147	119	96
75	Less: Income tax on Equity Return		72	66	64	67	70	73	69	61	53	45	36	29
76	Net Income (equal return on equity)		164	150	145	152	160	166	158	138	120	102	82	67
	Income Tax on Timing Differences													
77	Depreciation Expense		387	387	387	420	458	497	534	534	534	538	539	539
78	Less: Capital Cost Allowance	Line 92	351	246	254	355	442	499	442	309	227	173	123	121
79	Total Timing Differences		36	142	133	65	16	(2)	92	225	307	366	416	419
80	Income Tax on Timing Differences		11	43	41	20	5	(1)	28	69	94	112	127	128
81	Before Tax Revenue Requirement [=Line 52/(1-tax)]		16	62	59	28	7	(1)	41	99	135	161	183	184
85	**Total Income Tax**	Lines 75 + 81	88	128	122	95	77	72	110	159	187	205	219	213
	Capital Cost Allowance													
86	Opening Balance - UCC		1,169	818	573	864	1,149	1,356	1,472	1,030	721	567	411	288
87	Additions to Plant		0	0	545	640	650	615	0	0	73	17	0	228
88	Subtotal UCC		1,169	818	1,118	1,504	1,798	1,971	1,472	1,030	794	584	411	516
89	Capital Cost Allowance Rate		30.00%	30.00%	30.00%	30.00%	30.00%	30.00%	30.00%	30.00%	30.00%	30.00%	30.00%	30.00%
90	CCA on Opening Balance		351	246	172	259	345	407	442	309	216	170	123	86
91	CCA on Capital Expenditures (1/2 yr rule)		0	0	82	96	97	92	0	0	11	3	0	34
92	Total CCA		351	246	254	355	442	499	442	309	227	173	123	121
93	Ending Balance UCC		818	573	864	1,149	1,356	1,472	1,030	721	567	411	288	395