FORTISBC

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August 28, 2007

Via Email
Original via mail

Mr. R. J. Pellatt
Commission Secretary
BC Utilities Commission
Sixth Floor, 900 Howe Street, Box 250
Vancouver, BC V6Z 2N3

Dear Mr. Pellatt:

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

Further to FortisBC Inc.'s 2005 System Development Plan and BC Utilities Commission Order G-52-05 regarding the above noted project, please find enclosed for filing twenty copies of FortisBC's Application. In the previously referenced decision the Commission requested that a CPCN be filed for this project and noted:

> **"Distribution Substation Automation**: This [CPCN] is required because it is not clear to the Commission Panel what the possible risks and benefits are associated with the project, what precedent it may set for future projects, and if FortisBC is selecting the appropriate technology."

FortisBC feels that the attached application examines all of these areas and provides a clear justification for this program.

Sincerely,

David Bennett
Vice President, Regulatory Affairs
and General Counsel

AN APPLICATION FOR A

CERTIFICATE OF PUBLIC CONVENIENCE AND NECESSITY

DISTRIBUTION SUBSTATION AUTOMATION PROGRAM

AUGUST 28, 2007

FORTISBC INC.

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EXECUTIVE SUMMARY

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. It is a multi-year staged Program that focuses on reducing operational costs, preventing power outages and restoring power more quickly when there is a failure, as well as improving the levels of safety to employees and the public. The Program will commence in 2007 at a capital cost of $6.38 million to be completed by the end of 2011. The Program net present value (NPV) is estimated at $1.30 million with a one-time equivalent rate impact of 0.05%.

The term “automation” can imply a range of complexity. Systems can consist of relatively simple data logging and monitoring, or they can extend to highly automated schemes that can provide automatic restoration of customer load following system outages. This Application proposes implementing solutions for monitoring and control of the system as opposed to the more complex load restoration and auto-transfer schemes. A standard package of protection, monitoring and data collection equipment and system has been developed by FortisBC and is being applied to all new substation construction. The scope of this Application involves the installation of these systems to substations that are not currently slated for major upgrade or replacement in the foreseeable future.

This Program broadens the integration and use of remote monitoring and control to distribution level substations, including the quality monitoring of lines, transformers and feeders, fault recording and locating, and equipment condition monitoring. It will provide common communication mechanisms for gathering, storing, accessing and analyzing the accumulated data. The Program includes the development of a central data repository, individual equipment installation projects in appropriate substations, and an emergency backup plan.

This Program produces many specific benefits. Several will be realized immediately while others will come to fruition as data analysis occurs related to ongoing maintenance and capital replacement projects. One of the immediate benefits is the ability to operate switches remotely, allowing work to commence more quickly, as well as enabling the restoration of power more quickly during conditions of unplanned outage. Another example is the ability to meter individual distribution feeder loads, allowing planners to accurately determine electrical consumption at frequent intervals. This information can be used to move load between feeders and increase the efficiency of plant additions, as well as plan for new feeders and substations on a "just in time" basis.

Longer term benefits include more targeted maintenance planning. As an example, power transformer life can be more precisely measured over time, and new transformation can be planned and installed when the life of the unit is about to expire, as opposed to merely using peak load as the replacement indicator. The effect of this may be to extend the life of some transformers without incurring any greater system risk.

A list of the benefits associated with this Program is described in detail in this Application.

As described herein, savings are forecast to be realized in future operating and capital budgets as well as the potential deferral of some capital expenditures.

Utilities around the globe have recognized the benefits of these automation systems, which have lead to the development of a new industry standard. FortisBC has applied this approach in recently constructed substations and has received the commensurate benefits. To extract the maximum benefits in terms of operating costs, outage reduction and safety, this Application proposes to install automation systems in older substations that are not slated for major upgrade or replacement and that will form a significant part of the power system for years to come.

1. THE APPLICATION

FortisBC hereby applies to the British Columbia Utilities Commission, (the "Commission") pursuant to Sections 45 and 46 of the Utilities Commission Act, for a Certificate of Public Convenience and Necessity (the "Application") for the Distribution Substation Automation Program (the "Program") at a cost of approximately $6.38 million.

This Program is required to enable improved substation data collection, remote equipment operation, improved distribution reliability, and enhanced power system planning and safety.

The Program consists of installing automated control and data acquisition systems in 28 existing substations. All equipment design and operation is consistent with the equipment currently being installed in new substations in the FortisBC service territory.

2. THE APPLICANT

2.1. Name, Address, and Nature of Business

FortisBC Inc.
Landmark IV
Fifth Floor, 1628 Dickson Avenue
Kelowna, BC V1Y 9X1

FortisBC is an investor-owned, regulated utility engaged in the business of generation, transmission, distribution and sale of electricity in the southern interior of British Columbia.

2.2. Financial and Technical Capacity

FortisBC is an integrated utility serving over 150,000 customers directly and indirectly. It was incorporated in 1897 and is regulated under the Utilities Commission Act of British Columbia. The Company owns assets of approximately $670 million, including four hydroelectric generating plants with a combined capacity of 235 megawatts and approximately 6,400 kilometres of transmission and distribution power lines for the delivery of electricity to major load centers and customers in its service area. FortisBC employs approximately 500 full time and part time people. FortisBC has been engaged in the construction and operation of facilities of the type described above since its inception in 1897.

2.3. Contact Persons

Regulatory/Legal Contact:

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3. PROJECT DESCRIPTION

Substation automation is an all inclusive term used to describe the integration and use of system information from substations for the remote monitoring and control of substation equipment, the quality[1] monitoring of lines, transformers and feeders, fault recording and locating, equipment condition monitoring, automatic closed loop switching, as well as common communications mechanisms for gathering, storing, accessing and analyzing the resulting data. Resulting benefits are improvements in system performance, productivity, safety and economics.

This Program will ultimately enable remote operating and automated load and quality metering of all substations in the system. This will aid in averting equipment overloads and associated damage. The automation component will enable rapid remote circuit reconfiguration, thereby reducing outage times and reducing operating expenses associated with sending out crews to perform manual adjustments and switching. Equipment use will be better monitored, which will aid in the effective deployment of maintenance resources to the equipment experiencing the greatest loading.

The Program requires the installation of “intelligent” electronic devices at many substations for data capture, as well as building a communications network to substations with no existing remote communications, and building an informational database to accept the data.

3.1. Present Design Practices and Equipment Standards

Station automation system designs are appropriate for the size and importance of the station. For example, all of the systems that would be installed at a major transmission station would not necessarily be installed at a small rural substation. FortisBC has developed, through experience and

[1] Quality in this context refers to both “power quality” (such as voltage sags/swells, harmonics, etc.) as well as “service reliability” (such as the duration and number of outages).

industry consultation, a "suite" of automation equipment that provides the benefits desired without paying for unnecessary functionality.

The listed items, complete with their purpose, comprise the major automation systems that FortisBC is currently applying to new construction and is intending to apply to the legacy substations identified in this Application. It is important to note that:

a. The technology cited is not "cutting edge" or beta version. It is highly functional and has been market available long enough to have been reviewed and tested by many utilities;
b. FortisBC has installed this technology in other substations as part of recent upgrades. The equipment has been successful in enabling the desired outcomes. No untried technology is proposed as part of this Program.

3.1.1. Protection Relays

These microprocessor-based devices are highly sophisticated and allow for programmable logic to be incorporated. The units are very economical as compared to past technologies where it was necessary to install a large number of separate components. Essentially, the logic and monitoring capabilities are provided "free" along with the required protection elements. This allows the implementation of schemes that would not have previously been practical or affordable.

FortisBC has standardized on a single manufacturer for protection relaying equipment which reduces costs by reducing the number and variety of spare devices that must be maintained in inventory. Similarly, this common platform reduces training costs as there are few devices for technicians and engineers to become familiar with and ensures that the technicians have a good and ongoing understanding of the equipment as it is worked with routinely.

Equipment Standard: A selection of standard protection relays from Schweitzer Engineering Laboratories, Pullman WA, USA

3.1.2. Power-Quality Monitoring

These devices are becoming increasingly important as the FortisBC customer load continues to grow. In order to make intelligent decisions regarding system expansion it is necessary to know how much power is being delivered to any given location. Old-style electromechanical metering provides minimal information and hinders the planners' ability for optimal matching of system growth to load growth. Customers are also increasingly sensitive to power-quality disturbances that would have gone unnoticed in the past. These devices allow the tracking and the resultant resolution of power quality problems much more quickly than would otherwise be possible.

The meters are linked to an existing central monitoring and logging system which captures and stores the information for later use in a number of applications, such as power system load modeling. The database server is designed for high availability and has multiple central processing units ("CPUs"), hard drives and power supplies. The database contents are backed up nightly onto tape drives; these tape archives are then stored offsite for disaster survival.

Equipment Standard: Two standard meters from Schneider Electric (Power Measurement Ltd.), Victoria BC

3.1.3. Digital Fault Recorders ("DFRs")

DFRs are only installed at major terminal stations and are used to provide a complete record of station conditions when a fault or electrical disturbance occurs. These devices supplement the power quality monitoring and protection relaying. In general, these devices are not installed in distribution substations; however, a sufficient subset of their functionality is available in the protection and metering equipment discussed in the previous sections. This level of functionality is considered adequate for distribution-class substations.

3.1.4. Communications

A number of systems are used within FortisBC for inter-substation communications, dictated by station age and criticality within the power system. The preferred medium is fibre-optic cable due to its high reliability and capacity.

Included below are examples of the communications infrastructure that is currently in use or accepted by FortisBC, and is the proposal that forms the scope of this Program:

- Fibre-optic multiplexing equipment supplied by GE Multilin, Burnaby BC. This equipment is typically installed at larger substations and generating plants and provides very high bandwidth between these locations. This system has multiple levels of redundancy and thus has extremely high reliability. This is important as this system is also used to convey relay tele-protection communications between locations. Delays or failures in this signaling can directly affect the reliability and operation of the power system.
- Licensed 950 MHz digital wireless communications has been installed in Penticton and Kelowna to provide communications to the substations in these areas. This equipment has been supplied by GE Microwave Data Systems, Rochester NY, USA. This system is used for critical data such as System Control and Data Acquisition (“SCADA”) communications. At the present time, unlicensed systems are not considered secure or reliable enough for multi-point SCADA data links.
- Satellite communications supplied by TSAT of Norway has been successfully deployed at a number of remote substation locations. This system provides a low-bandwidth communications link to the FortisBC System Control Center. This equipment is ideal for small stations that have low data exchange requirements. It can also provide communications to isolated areas where other facilities are either not available or would be cost prohibitive to install.

- Unlicensed 900 MHz digital wireless communications has been installed in Penticton and Kelowna to provide network communications to the substations in these areas. This equipment has been supplied by GE Microwave Data Systems, Rochester NY, USA. As these systems are unlicensed (and may thus be susceptible to interference by other users), these radio links are only used to provide non-critical corporate wide-area network access to substation meters and relays. Unlicensed systems are also used in limited cases for point-to-point SCADA communications.
- POTS ("plain old telephone service") dialup lines are installed at numerous locations to provide remote access to relays and meters. This is acceptable where other methods of communication would be cost prohibitive or unjustifiable based on data bandwidth requirements. Since these connections are only established on an "as needed" basis, they are not useful for the real-time continuously available data circuits required for SCADA purposes.
- Cellular data and telephone leased lines are installed in locations where SCADA communication is required, but no alternate communication infrastructure is available. These circuits have good availability and provide a permanent connection to the remote location. However, leased lines have a relatively high on-going monthly cost and this provides a strong motivation to install FortisBC owned and operated infrastructure when/where possible.

3.1.5. Stations Included in the Program Scope

Those stations that will remain as part of the power system and are not currently slated for major upgrade in the next few years form the scope of the Program, and are identified in Table 1. The general type of equipment required, a cost estimate and a priority ranking for each location is also shown. The priority is based on the benefits to be derived. Considerations include rate of growth in an area (feeder metering benefit), the distance from a staffed headquarters (remote tagging benefit), the overall absence (or existence) of current automation and so on. The status for each station indicates the functionality of the station at the time of submission of this Application, including previously approved capital improvements that are scheduled for 2007/2008 installation.

TABLE 1

Priority	Abr	Station Name	Metering	Metering Comm.	Relaying	RTU	Comm. Processor	Tagging	Construction Year	Cost ($000s)
1	DGB	Bell Terminal						X	2008	24
1	CAS	Castlegar	X		X	X	X	X	2008	345
1	DUC	Duck Lake	X				X	X	2008	131
1	FRU	Fruitvale					X		2008	42
1	GLE	Glenmore			X			X	2008	125
1	HOL	Hollywood			X		X	X	2008	375
1	KER	Keremeos					X	X	2008	54
1	SUM	Summerland			X	X			2008	89
2	BEP	Beaver Park				X	X		2009	152
2	BLU	Blueberry		X		X	X		2009	140
2	OKM	OK Mission			X		X	X	2009	383
2	OSO	Osoyoos			X			X	2009	122
2	PLA	Playmor				X	X	X	2009	183
2	SAU	Saucier	X						2009	37
2	VAL	Valhalla				X			2009	91
2	WES	Westminster	X	X		X			2009	140
3	CHR	Christina Lake	X	X		X			2010	180
3	GLM	Glenmerry				X	X	X	2010	186
3	HED	Hedley	X		X	X	X	X	2010	348
3	SAL	Salmo				X	X		2010	155
3	TRC	Trout Creek	X	X		X			2010	223
3	WEB	West Bench	X	X	X	X	X		2010	286
4	HUT	Huth	X	X			X	X	2011	190
4	PAS	Passmore	X	X		X			2011	139
4	SEX	Sexsmith			X		X	X	2011	272
4	SLO	Slocan City				X			2011	95
4	STC	Stoney Creek	X	X	X	X	X		2011	291
4	TAR	Tarrys	X	X	X	X	X	X	2011	348
Subtotal:										**5,146**

Note: “X = work required”

3.2. Stations Excluded

As previously discussed, all new stations will be built with standardized FortisBC station automation systems. The costs of these systems are included in the individual project budgets and therefore these stations are not included within the scope of this Application.

These new distribution stations include:

a. COT – Cottonwood Substation (south of Nelson)
b. AWA – Arawana Substation (Naramata)
c. KET – Kettle Valley Substation (east of Rock Creek)
d. NKM – Nk'Mip Substation (east Osoyoos)
e. BWS – Big White Substation (Big White Village)
f. ELL – Ellison Substation (north Kelowna)
g. BLK – Black Mountain Substation (east Kelowna)
h. OOT – Ootischenia Substation (east of Castlegar)

As well, there are a number of older substations that will be retired in the near future and therefore will not be included in this Program. These are:

a. NAR – Naramata Substation (to be replaced by Arawana in another location)
b. WYN – Wynndel Substation (replaced by new distribution facilities at AA Lambert)
c. ROC – Rock Creek Substation (to be replaced by Kettle Valley)
d. MID – Midway Substation (to be replaced by Kettle Valley)
e. GRE – Greenwood Substation (to be replaced by Kettle Valley)
f. PAT – Paterson Substation (retired as part of the Rossland voltage conversion)
g. WHI – Whitewater Substation (to be replaced by Cottonwood Substation)
h. YMR – Ymir Substation (to be replaced by Cottonwood Substation)

Finally, there are a number of stations that are under review by FortisBC Planning either for major station reconstruction or replacement. Since the future of these sites is unclear they are excluded from this program. If it is determined that a substation rebuild is appropriate, then the costs of adding automation systems would be included in a future capital plan or CPCN application.

These stations include:

a. RUC – Ruckles Substation (to be upgraded in the future – this site will be included in a future Capital Plan submission)
b. KAL/OKF – Kaleden and OK Falls Substations (these may either be rebuilt or combined as a single new substation).

3.3. Individual Scopes of Work

Table 2 describes the high-level scope of work required for the individual substations identified in Table 1. Upon approval of the Program, detailed scoping and estimating would be carried out for each location.

TABLE 2

ABR	Station Name	Scope of Work
BEP	Beaver Park Substation	Install communications processor Upgrade station RTU
BLU	Blueberry Substation	Install communications processor Install station RTU Connect existing meter for transformer monitoring Install communications to System Control Center Install dial-up phone line for access to relays and meters
CAS	Castlegar Substation	Upgrade feeder relaying Install per-feeder metering Connect existing meter for transformer monitoring Install communications processor Install remote tagging switches Install station RTU Install communications to System Control Center
CHR	Christina Lake Substation	Install feeder metering Install station mini RTU Install communications to System Control Center Install dial-up phone line for access to meters
DGB	Bell Terminal	Install remote tagging switches
DUC	Duck Lake Substation	Install transformer monitoring Upgrade feeder metering Install communications processor Install remote tagging switches
FRU	Fruitvale Substation	Install communications processor
GLE	Glenmore Substation	Upgrade feeder protection Install transformer monitoring Install remote tagging switches
GLM	Glenmerry Substation	Install remote tagging switches Install communications processor Install station RTU Install communications to System Control Center
HED	Hedley Substation	Upgrade feeder relaying Install per-feeder metering Install transformer monitoring Install communications processor Install remote tagging switches Install station RTU Install communications to System Control Center

TABLE 2 CONT'D

ABR	Station Name	Scope of Work
HOL	Hollywood Substation	Upgrade feeder protection Install communications processor Install remote tagging switches
HUT	Huth Substation	Upgrade feeder metering Install communications processor Install remote tagging switches Install transformer monitoring Install wireless network communications
KER	Keremeos Substation	Install transformer monitoring Install remote tagging switches Install communications processor
OKM	OK Mission Substation	Upgrade feeder protection Install remote tagging switches Install communications processor
OSO	Osoyoos Substation	Upgrade feeder protection Install remote tagging switches
PAS	Passmore Substation	Install feeder metering Install station mini RTU Install communications to System Control Center Install dial-up phone line for access to meters
PLA	Playmor Substation	Install station mini RTU Install communications to System Control Center Install communications processor
SAL	Salmo Substation	Install communications processor Install station RTU Install communications to System Control Center
SAU	Saucier Substation	Install transformer monitoring
SEX	Sexsmith Substation	Upgrade feeder relaying Install communications processor Install remote tagging switches
SLO	Slocan City Substation	Install station mini RTU Install communications to System Control Center
STC	Stoney Creek Substation	Upgrade feeder relaying Install feeder metering Install transformer monitoring Install station mini RTU Install communications to System Control Center Install dial-up phone line for access to meters
SUM	Summerland Substation	Install transformer monitoring Install station mini RTU Install communications to System Control Center

TABLE 2 CONT'D

ABR	Station Name	Scope of Work
TAR	Tarrys Substation	Upgrade feeder relaying Install per-feeder metering Install transformer monitoring Install communications processor Install remote tagging switches Install station RTU Install communications to System Control Center Install dial-up phone line for access to relays and meters
TRC	Trout Creek Substation	Install feeder metering Install transformer monitoring Install station mini RTU Install communications to System Control Center Install dial-up phone line for access to meters
VAL	Valhalla Substation	Install station mini RTU Install communications to System Control Center
WEB	West Bench Substation	Install feeder metering Upgrade feeder relaying Install communications processor Install station RTU Install communications to System Control Center Install dial-up phone line for access to relays and meters
WES	Westminster Substation	Install transformer monitoring Install station RTU Install communications to System Control Center Install dial-up phone line for access to relays and meters

3.4. Project Schedule

Program implementation will occur over a five year time period.

In 2007 the following activities are planned to take place:

Pre-regulatory approval:

- Preliminary (+/-25%) engineering estimating
- CPCN preparation and submission

Post-regulatory approval:

- Detailed scoping and estimating (+/-10%)
- Material takeoffs and vendor negotiations
- Initial engineering design and procurement.

The relative priority ranking scale described in Table 1 also represents the year of implementation. On-site construction will commence in 2008 with completion in 2011. The construction schedule is summarized in Table 3.

TABLE 3

Year	Region	Number of Stations
2008	Kootenays	2
	Okanagan	5
2009	Kootenays	4
	Okanagan	4
2010	Kootenays	3
	Okanagan	3
2011	Kootenays	3
	Okanagan	4
Total		**28**

3.5. Project Cost

The program is composed of two main components:

1. Equipment installations within substation sites, and
2. Data collection and archiving server hardware and software.

As described in Table 4 below, the total cost of the Program is estimated to be $6.38 million (+/-25%) with expenditures occurring over a five year period. This figure is in as-spent dollars and includes a 10% contingency allowance. This estimate compares favourably with the $5.8 million cost which was originally submitted in the FortisBC 2005 System Development Plan (as that value was in 2004 dollars). The apparent increase is due to inflation since that time and over the installation period of the Program.

The Program NPV is estimated at $1.30 million with a one-time equivalent rate impact of 0.05%. A detailed calculation of the revenue requirements is presented in Appendix 1. For the purposes of this application the revenue requirements calculation has been carried out to 20 years as much of the equipment to be installed by the program is expected to reach this lifespan.

In calculating the Program NPV, an “Annual Cost Reduction” from Table 5 has been applied as a reduction to future operating and capital costs. This value is the estimated yearly savings that are expected to be achieved on completion of the Program. An average of the “Estimated Minimum” and “Estimated Maximum” values has been used in the calculation as an assumption. Thus, a value of $590,000 is used for the initial savings starting in 2011. This cost reduction has been apportioned as follows: 20% of the savings ($118,000) to a reduction in operating costs (line 56 in Appendix 1) and 80% of the savings ($472,000) to a reduction in future capital costs (line 48 in Appendix 1). This allocation was chosen as the majority of the quantifiable program benefits due to remote operation of switching devices will be attributed to future capital projects. This is true even for forced outages; for widespread outages where the benefits of automation would be most applicable, the outage costs would be capitalized due to the large amount of power system infrastructure that is replaced.

Note that the financial benefits listed in Table 5 are partially offset by additional operating costs (mainly due to leased-line and communications monthly charges) that will be required for some installations. FortisBC attempts to minimize the use of leased communications and prefers to install utility-owned and operated infrastructure where it is possible and cost effective.

TABLE 4

Installation / Substations	2007	2008	2009	2010	2011
	($000s)				
Bell Terminal		24			
Castlegar		345			
Duck Lake		131			
Fruitvale		42			
Glenmore		125			
Hollywood		375			
Keremeos		54			
Summerland		89			
Beaver Park			152		
Blueberry			140		
OK Mission			383		
Osoyoos			122		
Playmor			183		
Saucier			37		
Valhalla			91		
Westminster			140		
Christina Lake				180	
Glenmerry				186	
Hedley				348	
Salmo				155	
Trout Creek				223	
West Bench				286	
Huth					190
Passmore					139
Sexsmith					272
Slocan City					95
Stoney Creek					291
Tarrys					348

TABLE 4 CON'T

Installation / Substations	2007	2008	2009	2010	2011
	($000s)				
Additional costs:					
Estimating/Engineering/Procurement	462	0	0	0	0
Data server hardware & software	0	140	33	0	0
Contingency (10%)	46	132	128	138	134
AFUDC	18	0	0	0	0
Total Annual Capital Cost	526	1,456	1,409	1,516	1,470
Total Capital Cost	**6,378**				
Net Present Value	**1,301**				
One Time Rate Impact	**0.05%**				

4. PROJECT JUSTIFICATION

The ultimate goal of implementing the Substation Automation Program is to improve employee and public safety, power quality and reliability as seen by the customers. In this section, specific examples are provided to demonstrate the actual improvements and resulting benefits. These benefits are both immediate and long term and are summarized in Table 5 and described in detail in this Section.

TABLE 5 - PROGRAM BENEFITS

Section	Category	Cost Savings Quantifiable (within 25% accuracy)?	Annual Cost Reduction (estimated minimum)	Annual Cost Reduction (estimated maximum)	Other Cost Comments	Reliability Enhanced?	General Comments
4.1	Remote Visibility	N				Outages can be reduced in length, and potential future outage causes better identified	
4.2	Load Forecasting	N			Increased knowledge about the feeder loading profile allows load balancing both intra- and interfeeder, reducing the possibility of premature capital expenditure for new feeders.	Feeder loading data allows prudent load transfers based on time of day, reducing the stress on highly loaded feeders	
4.3	Maintenance Planning	Y	$40,000	$80,000			Based on reduced frequency of formal substation meter reading.
4.4	Revenue Protection or Loss Analysis	N			Partial recovery of an estimated annual $2.4 million in power losses.		Recovery potential increases with the collection and analysis of load data.
4.5	Safety	N				Reduced response times to troubleshoot substation problems.	Advanced indication of critical substation alarms.
4.6	Operating Authority	N		$100,000	Field crews available for restoration efforts rather than PIC duties.		
4.7	Remote Operation	Y	$397,000	$397,000		Conservatively eliminate 9,000 customer outage hours per year	
4.8	Metering	N				Load balancing and load transfer between feeders will reduce the chance of distribution outages due to feeder overload.	
4.9	Intelligent Relaying	Y	$45,000	$120,000	Potential for future capital cost deferral based on the use of transformer temperature tracking technology as opposed to nameplate capacity exceedance only.		
4.10	Reduced maintenance	N			Routine maintenance of electromechanical relays will no longer be required.	Proactive warning of relay failures can prevent larger outages if backup protection is require to operate in place of primary protection.	
4.11	System Security	N					Supports the functions listed above.
4.12	Central Database	N					Supports the functions listed above.
	Totals		**$482,000**	**$697,000**			

4.1. Remote Visibility

To effectively determine the required capacity at a supply point it is necessary to have accurate real-time information on system loading at that point. In the case of a distribution substation, ideally it would be possible to have load information (both real and reactive power) for each distribution feeder. As well, information on the station ambient temperature as well as the power transformer oil and winding temperatures should be provided. Together, this information gives the complete load profile.

In addition, the system reliability indicators that are affected are both the duration and frequency of outages. Older equipment provides little information post-fault to assist with locating the cause of a fault. This results in unnecessarily long outages as feeder problems are traced. This involves electricians and power line technicians (“PLTs”) spending time at the station and along feeder circuits, searching for the problem. In the absence of specific fault related data, the investigation may require several tradesmen and technicians to conduct equipment tests as well as look for physical causes. This not only incurs unnecessary cost, but takes the skilled workers away from other more proactive work. This exposes the customer to both increased cost and longer and/or avoidable outages.

Substation protection equipment failures have also been known to cause outages where no actual problem existed. For example, in 2002 Recreation Transformer 1 tripped five times due to a wiring failure in the transformer protection. Tracing the source of the misoperation was difficult due to the lack of recording equipment at this location. Similar incidents occurred with Transformer 3 at FA Lee Terminal station in 2003 and Transformer 1 at AA Lambert Terminal station in 1999. Once monitoring equipment and upgraded protection was installed, the problems were quickly found and corrected. Installing this equipment at other locations will help reduce or prevent future outages.

4.2. Load Forecasting

Detailed and accurate load information is required to make correct network planning decisions. With historical station load and load factor data information available, it is possible to deploy capital expenditures in a strategic fashion. Where electronic metering is not deployed, previous area and station loading was estimated based on the peak demand reading from the station ammeters, installed either on the transformer or each feeder. Unfortunately, this reading is simply a snapshot in time – it provides no information regarding when the peak was reached, how long it lasted, or what load transfers may be impacting the levels. Modern meters have the capability to record data on a periodic interval. From this data an accurate load profile and load factor can be calculated. This is critical to ensure that required capacity is installed where and when it is required.

4.3. Maintenance Planning

In order to make correct decisions regarding the appropriate amount of system maintenance, it is necessary to understand the past performance of the system. Previously, maintenance schedules were usually calendar driven and did not necessarily account for the service duty of individual pieces of equipment. For example, all high-voltage oil circuit breakers might be overhauled every five years. This does not account for the number of operations or actual current interrupted by the breakers. Thus, in some cases, a breaker may have been “over-maintained” for its service duty (i.e. low operations count, or low fault level) while other breakers that saw more severe service should have actually been maintained more frequently. An automated data-collection platform can greatly assist in making effective maintenance decisions.

Critical information that directs the maintenance schedule includes:

- Circuit breaker operations count;
- Circuit breaker cumulative interrupted current;
- Peak and/or demand current values;
- Tap changer operations count;

- Transformer oil and winding temperatures;
- Ambient temperature.

Historically, this information has been collected on a monthly basis for each substation by dispatching a substation electrician to read the electromechanical station meters. As previously described, many of these values are monthly high readings and do not offer a chronology of events.

There is also a cost associated with this monthly reading. Automation will not only allow a greater range of information to be created, the labour and data entry costs associated with these monthly checks will also be largely avoided. As an example of savings, the 2005 total for this activity was approximately $120,000. With the implementation of this Program, it is expected that these inspections could be reduced to bimonthly or quarterly, reducing the annual inspection cost by between $40,000 and $80,000 annually.

FortisBC has recently purchased and installed a new Computerized Maintenance Management System ("CMMS"). This system can directly link to the station automation central database to automatically trigger maintenance work orders or email warnings if unusual conditions are detected. Preventive action can then be taken to reduce the likelihood of premature loss of equipment life.

4.4. Revenue Protection and Loss Analysis

All electric utilities encounter system losses. Losses labelled as technical are:

- Transformer resistance and magnetizing losses;
- Transmission line resistance losses; and
- Distribution line resistance losses.

Non-technical/commercial losses are:

- Customer installations, such as unbilled streetlights or traffic lights;
- Billing errors; and
- Power theft.

System losses are replaced either by increasing local generation where possible, or by purchasing more bulk power through supply contracts, both of which are quantifiable non-recoverable costs, so any effort to reduce these losses has an immediate and positive effect.

While some of these losses are unavoidable (all power transmission lines exhibit resistance losses), they can be minimized by optimizing system design. For example, transmission line losses can be minimized by increasing the operating voltage or using larger conductors with lower resistance or reconfiguring the system flows. Present day transformer designs are highly efficient and typically have lower losses than older transformers. As new facilities are planned, designed and constructed, these factors are considered. However, replacing transformers or changing system voltages involves capital cost expenditures that must be justifiable including the value of the reduced losses they create.

Determining losses, either in real-time or historically, is time consuming and complex without adequate data for purposes of analysis. It requires the knowledge of the total system production (total local generation plus imports) and the total customer load at any point in time. If these are known the two can be subtracted to determine the loss value. In the FortisBC system the total system production is known to a high degree of accuracy. Both the instantaneous and hourly energy output of all generating units is known and delivered to the System Control Center. The same is true for all of the high voltage tie-lines to other utilities. The energy delivered to metered loads can be identified “after the fact” from the billing system, however, the magnitude of losses within various sections of the transmission and distribution system in many cases must be estimated by system modelling. Additional load monitoring would provide a higher degree of accuracy to these estimates enabling more efficient operation of the system and subsequent reduction of losses.

FortisBC total system losses are estimated to be 9.5%, while system modelling has calculated technical losses to be in the area of 9%. Using the average annual load, the total system average losses are in the order of 38 MW. Considering a single MW can result in a power purchase cost of up to $300,000 annually, there is significant potential for cost savings by reducing both un-metered and technical losses through more accurate information. It is not unreasonable to expect with better data that at least 1-2% of these system losses could be targeted and reduced if not even fully eliminated. With each 1% of loss reduction equivalent to approximately 4MW of load loss, the potential financial benefits are as high as $2.4M annually.

4.5. Safety

The systems to be installed in this Program enable the System Control Center to gain visibility of critical alarms in real-time. This provides an immediate indication that the system is not operating as required; personnel can then be dispatched to the location to troubleshoot and correct the problem. This array of alarms includes:

- Station DC battery monitoring – remote alarming if protection is disabled;
- Transformer temperatures/gas levels/oil levels – warnings of imminent failures/outages or oil leakage;
- Breaker low gas and trip circuit failure alarms – remote alarming if protection is disabled;
- Intrusion and fire detection alarms – these warn of abnormal conditions or unauthorized access to substation control rooms.

As an example, if the location of a problem is known to a high degree of certainty, the crew can be dispatched with equal certainty, reducing overall restoration time. If required, emergency response procedures can also be activated more quickly, reducing public and environmental risks.

4.6. Operating Authority

FortisBC is centralizing the duties of the distribution person-in-control ("PIC") and this function will be performed by a dedicated dispatcher at the System Control Center. In the past, the field crews performed the distribution PIC duties and had to physically travel to each substation to operate devices and take station readings. To effectively perform this function from the central System Control Center dispatchers require real-time information about substation equipment such as breaker status, feeder and transformer loadings and bus voltages. This allows them to make appropriate operating decisions and deal with situations as they arise without undue delay.

In addition to the operating efficiencies, WorkSafeBC, the governing authority for worker health and safety regulates the operation of the high voltage power system. Occupational Health and Safety Regulation Part 19.19 states:

> *"19.19 Person in charge*
>
> *(1) One person must be assigned at any one time the exclusive authority as the person in charge to establish the conditions for, and to issue safety protection guarantees for, the power system or a part of it.*
>
> *(2) The person in charge must*
>
> *(a) ensure that the* ***status of the power system or assigned part of the power system is accurately represented on a mimic display*** *[emphasis added]."*

The crucial factor is being able to ensure that the PIC has real-time status of the power system under his/her control, all the while ensuring that they retain control of the system. While it is possible to comply with the Regulation in the absence of automated data collection and remote system operation, the required protocols are more labour intensive, require manual systems of communication and status recording and are to a greater degree open to human error. When the assumption of PIC duties by the System Control Center was initially reviewed, there were two notable benefits identified. The degree of employee safety was considered to be higher since control and status of the system was under the control of a single entity. Secondly, since the field crews were engaged in power restoration and operation and less so in performing PIC duties while in the field, annual operation costs could be reduced by as much as $100,000 depending on the number of outages and the number of crews working on the power system.

4.7. Remote Operation

There are distinct and discrete benefits associated to having a greater degree of SCADA visibility and control at the System Control Center.

a. **Reliability.** Over the last four years FortisBC has averaged 60 feeder outages per year. The average number of customers per feeder (based on those feeders which had outages) is about 850. Many of these outages are in areas remote from the substation, and where a member of the restoration crew must travel to the substation to manually switch to re-energize the feeder. Approximately 30% of these outages were on feeders that originate in substations that already have remote switching capability.

   If the outage time is reduced by 30 minutes[2] for the 42 outages per year where there is no remote capability, the result is a reduction of 18,000 customer-hours per year. However, on occasion there are methods already employed to reduce outage duration. An employee may be left at the station, ready to switch when the line integrity has been restored, albeit at the

[2] A typical travel time from an outage location back to the substation (to perform switching to reenergize a feeder) is 30 minutes on average.

additional cost of that employee's wages. Additionally, some faults occur at locations less than 30 minutes travel time from the station. Therefore, a conservative estimate of reliability improvement is that 30 minutes can be eliminated from one half of those 42 outages, creating a benefit of 9,000 customer-hours per year.

It should also be noted that as the number of customers connected to the system increases with growth, the reliability improvement increases accordingly.

b. **Energy metering**. Wider and more exact visibility and monitoring of system load flow will allow more exact energy and VAR (volt-ampere reactive) management, improving system performance and reducing energy costs.

c. **Recloser enabling and disabling**. When crews are brushing a rural line or working on a line that is energized, automatic reclosers must be disabled for safety reasons, requiring one visit to the substation by a PLT in the morning to disable reclosing, and one in the evening to re-enable it. Remote control avoids these labour costs. In 2005, there were approximately 2,350 Guarantee of Non-Reclose permits ("GNRs") issued to ensure that work could be done safely. Approximately 15% of GNRs do not require a separate trip to the substation (such as when there are multiple crews working on the same feeder) and about 10% are issued from stations that already have feeder recloser automation. The switching costs are described herein:

i) Direct switching costs:

Hourly PLT rate (including loadings) = \$75/hour

Average travel and tagging time per GNR = 1 hour

Number of GNRs that require dedicated time = 2350 x (1 – 0.1) x (1-0.15) = 1,800

GNR direct cost - \$135,000/year

ii) Crew must often wait to start work until the switching at the substation is completed and the GNR is issued, confirming that if there is a line fault the circuit will not be re-energized. The estimated crew downtime costs are:

a. Brushing crews: 1,000 hours per year @ $150/hour = $150,000/year

b. Line crews: 1,500 hours per year @ $75/hour = $112,500/year

Total estimated crew downtime costs = $ 262,500/year

d. **Line source switching.** Where distribution substations (for example, Playmor, Tarrys, and Christina Lake) can be fed from two transmission lines remote control of line switches enables faster restoration switching, and avoids labour costs to dispatch a PLT.

e. **Tap changer operation**. Extending remote control to more distribution tap changers will help to avoid exceeding the peak energy capacity penalty threshold by applying controlled voltage reduction.

f. **Support for future feeder distribution automation**. As an example, the Program supports the future installation of midpoint line reclosers which can localize the outage effects of a distribution fault, reducing the overall number of customers affected.

g. **Breaker switching**. Once the problem causing a line fault has been discovered and rectified, the PLT in the field can then contact the System Control Center and confirm the line is safe to re-energize. This can then be done remotely by the System Control Center rather than have the PLT in the field return to the substation and close the distribution breaker. Currently, the outage continues while the PLT travels to the substation to switch the breaker. With automation in place, this additional outage time can be eliminated.

h. **Feeder switching**. Reconfiguring the local distribution system can be accomplished more rapidly with the ability to switch the feeders remotely. Examples of benefits include:

- feeding a distribution circuit from another transformer to alleviate loading concerns on the original transformer;
- restoring non-faulted feeders faster under station fault conditions once the failure has been identified and isolated.

4.8. Metering

Power system operation will be greatly enhanced with the ability to acquire specific time based load data. In particular:

a. **Individual feeder metering**. More accurate load profiling, including the information related to time of day and temperature variability will assist in system load balancing. This in turn will reduce the potential for outage and minimize the strain placed on power system equipment.

b. **Electronic metering**. As opposed to the electromechanical meters that are presently in place, electronic meters improve time resolution of load data and provide improved monitoring of power quality factors. More accurate load profiling improves forecasting and power system planning, ensuring the appropriate and timely deployment of capital expenditures. Improved quality data enables focused troubleshooting and thereby improves customer service as it relates to power quality.

More timely data analysis results in faster corrective actions.

4.9. "Intelligent" Relaying

Continuous improvement in electronic technology over the past number of years, including the advent of microprocessors in substation relays, has lead to a much greater ability of the equipment to identify, track and respond to specific problems on the power system. This electronic "intelligence" allows troubleshooting and restoration to be targeted at the problem, with much less time spent by technicians trying to identify what and where the problem is. Specific data that will be acquired and logged includes:

a. Fault Location. With the existing technology, line crews patrol a faulted circuit to determine the nature and location of the fault. The time spent on this patrol activity is completely dedicated to finding the fault, and can be reduced with the use of relays that locate the fault with a higher degree of accuracy. Crew time is better utilized as they spend the bulk of the effort correcting the problem, not searching extensively for it. Restoration time also improves as the relay does the work of better identifying the fault location, enabling crews to be dispatched to a more specific location. While feeder fault location is not entirely accurate (due to the non-homogeneous nature of feeder circuits), the fault location is still useful in providing the relative location of faults.

b. Fault Recording. Collecting and accessing a significantly more detailed event record allows the causes and locations of faults to be analyzed and appropriate remedial action taken. This may include enhanced brushing in certain corridors, equipment replacement/repair, or line relocation as examples. As it pertains to outages and power restoration, there is an added benefit to using more advanced technology. If the outage results from an equipment malfunction within the confines of the substation, the nature of the problem is more likely to be identified by the monitoring devices, which are able to report when they have failed as well as identify the failures of other system components. This saves valuable time and prevents a field patrol of the line, which is standard procedure when equipment trips off and is “locked out”.

c. Condition Monitoring. The highest degree of power system complexity is located within the substation fence. Having detailed ongoing knowledge about the state of equipment allows condition-based, “just in time” maintenance to occur. Currently, most maintenance is time based. However, equipment maintenance is more suitably driven by equipment condition, which can only be done with the availability of condition related data. Information such as the number of circuit breaker operations, transformer oil temperature, dissolved gas values and feeder loading will allow the maintenance cycles to be aligned with the duty that the equipment has performed. Light duty over a period of time will extend the maintenance intervals, thereby reducing the maintenance costs.

For example: the scheduled maintenance for a 63 kV SF6 breaker takes an average of 220 man-hours to maintain, with a maintenance cycle of about six years. This equates to a maintenance cost of approximately $50,000 per breaker. If the maintenance on one third of these units could be deferred for two years based on a known lower operation duty, the net result is an average cost reduction of approximately 25%. With approximately 60 such breakers in the system, in any given year it is expected that 10 would be maintained. One third of these units represent a cost of $170,000 annually, which would be reduced to $125,000, for an annual cost savings of $45,000.

d. Transformer Replacement. Currently, when the forecast annual peak load on a large power transformer reaches the nameplate capacity, planning commences for replacement of the unit. Typically, it takes approximately two to three years for planning, engineering, tendering and construction. During this period, as a function of customer growth, the peak load may exceed the nameplate capacity. This is an acceptable risk given that transformer life is normally limited by winding insulation degradation, and relatively short periods of excessive load do not cause significant damage. Insulation is degraded primarily as a result of ongoing heating.

It may be possible to keep a transformer in service for even longer periods of time with the availability of consistent, reliable station data. While energized and serving load, the transformer winding does not heat equally, and “hot spots” are created. It is these locations inside the winding, hotter than the average winding temperature that causes the greatest damage and thereby limits the life of the transformer. However, during periods of lower load the temperature rise is not as great and the life of the transformer is reduced at a lower rate.

The availability of this information, coupled with information about historical faults on the unit makes it possible for planning engineers to review the “life reduction” of the transformer and better determine how much longer it can safely remain in service. The benefit is seen in the deferral of capital replacements, which in turn limits future rate increases. As an example, a substation transformer replacement typically costs approximately $2,000,000. A one year deferral would result in a financial benefit of approximately $75,000.

4.10. Reduced Maintenance Costs

A significant benefit that will be gained from the Program is that all remaining electromechanical meters and relays on distribution feeders will be upgraded to modern standards. This will reduce future maintenance costs as routine relay testing will no longer be required. As well, replacement parts are becoming increasingly difficult to locate for some types of older relays. Some instances of forced upgrades have already occurred when devices have failed and it was either impossible to locate spare parts or it was not cost effective. A recent example occurred in 2006 when a lightning strike near the OK Mission Substation damaged five distribution feeder reclosing relays. Repairing the devices was not practical as replacement components were not available. Instead, it was necessary to replace the units with new microprocessor-based protection relays.

Microprocessor-based relays have self-diagnostic circuitry that can provide an alarm indication if a device malfunctions. Since the Program will also ensure that the SCC has visibility of all substations, immediate alarming of relay failures will be provided for all locations. This will allow for much quicker response to equipment failures rather than having to wait until a scheduled maintenance interval to determine that a device has failed.

4.11. System Integrity and Security

Station automation reduces the need for redundant sensors, wiring and transducers, which ultimately reduces the capital investment. Unauthorized access and operation is also prevented, enhancing power system “cyber-security”. The FortisBC standard is to ensure forced separation of the operational power system controls such as relaying and SCADA, and those functions that are "read only", including data logging and equipment monitoring. The Program enables that standards be met and the inherent system security be employed.

4.12. Central database

A significant advantage of microprocessor based systems over their electromechanical predecessors is the ability to collect and log large amounts of data. Once established, the database is continually repopulated creating a history of conditions and equipment performance. Such a growing volume of data becomes a more reliable predictor of future performance, allowing planning engineers to evaluate system needs based on actual performance. Both maintenance and capital upgrade programs can be tailored to the specific needs of the power system rather than relying on manufacturers suggestions and peak load data. The customers become the direct beneficiary on two fronts – greater levels of reliability and lower future costs.

In order to gain the full benefits of the Program, new server hardware and software will be installed in the FortisBC Data Centre. This server will be responsible for collecting, aggregating and archiving the data that is received from numerous data sources. These sources include the SCADA system, the power-quality metering system and the Computerized Maintenance Management System.

The server will provide a user-friendly web-based interface that will allow users to easily retrieve both historical and real-time data.

5. PUBLIC CONSULTATION

As this Program does not require large new infrastructure to be constructed (the majority of the work will be carried out within the substation control buildings), no public consultation is planned.

6. OTHER APPLICATIONS AND APPROVALS

Approvals from agencies other than the BC Utilities Commission are not required.

Appendix 1 – Revenue Requirements Analysis

2006-2026

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 59	0	10	25	45	-53	-54	-55	-56	-57	-58	-59	-61
2	Depreciation Expense	Line 64	0	0	53	198	339	491	591	542	493	443	392	-142
3	Carrying Costs	Line 71	0	20	93	192	283	346	325	245	168	95	24	-26
4	Income Tax	Line 85	0	-33	-120	-173	-191	-157	-18	112	193	240	263	61
5	Total Revenue Requirement for Project		0	-3	51	262	378	627	843	844	797	719	619	-167
6	**Net Present Value of Revenue Requirement**	10.00%	1,301											
	Rate Impact													
7	**Forecast Revenue Requirements**		209,300	226,200	244,100	249,000	254,000	259,100	264,300	269,600	275,000	280,500	286,100	291,800
8	Rate Impact		0.00%	0.00%	0.02%	0.11%	0.15%	0.24%	0.32%	0.31%	0.29%	0.26%	0.22%	-0.06%
	Annual Incremental Rate Impact over previous year		0.00%	0.00%	0.02%	0.08%	0.04%	0.09%	0.08%	-0.01%	-0.02%	-0.03%	-0.04%	-0.27%
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%	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%	9.19%	9.19%	9.19%	9.19%	9.19%	9.19%	9.19%	9.19%	9.19%	9.19%	9.19%
13	Debt Return		6.40%	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			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						-472	-481	-491	-501	-511	-521	-532	-542
49	Total Cash Outlay in Year		**526**	**1,456**	**1,409**	**1,516**	**998**	**-481**	**-491**	**-501**	**-511**	**-521**	**-532**	**-542**
50	Cumulative Cash Outlay		526	1,983	3,392	4,908	5,906	5,424	4,933	4,432	3,921	3,400	2,869	2,327
51			0	0	0	0	0	0	0	0	0	0	0	0
52	Cumulative Project Cost		526	1,983	3,392	4,908	5,906	5,424	4,933	4,432	3,921	3,400	2,869	2,327
53	Additions to Plant		0	526	1,456	1,409	1,516	998	-481	-491	-501	-511	-521	-532
54	Cumulative Additions to Plant		0	526	1,983	3,392	4,908	5,906	5,424	4,933	4,432	3,921	3,400	2,869
55	CWIP		526	1,456	1,936	3,499	4,390	4,427	5,415	4,923	4,422	3,911	3,390	2,858
	Annual Operating Costs / (Savings)													
56	Estimated Cost Savings						-118	-120	-123	-125	-128	-130	-133	-136
57	Communications - Leased Line Costs			10	20	40	60	61	62	64	65	66	68	69
58	Software Maintenance Costs				5	5	5	5	5	6	6	6	6	6
59	Total Incremental Operating Costs (Savings)		0	10	25	45	-53	-54	-55	-56	-57	-58	-59	-61
	(Forecast inflation rate 2%)													
	Depreciation Expense													
60	Opening Cash Outlay		0	0	526	1,983	3,392	4,908	5,906	5,424	4,933	4,432	3,921	3,400
61	Additions in Year	Line 53	0	526	1,456	1,409	1,516	998	-481	-491	-501	-511	-521	-532
62	Cumulative Total		0	526	1,983	3,392	4,908	5,906	5,424	4,933	4,432	3,921	3,400	2,869
63	Depreciation Rate - composite average		10.00%	10.00%	10.00%	10.00%	10.00%	10.00%	10.00%	10.00%	10.00%	10.00%	10.00%	10.00%
64	Depreciation Expense		0	0	53	198	339	491	591	542	493	443	392	-142
	Net Book Value													
65	Gross Property	Line 54	0	526	1,983	3,392	4,908	5,906	5,424	4,933	4,432	3,921	3,400	2,869
66	Accumulated Depreciation		0	0	-53	-251	-590	-1,081	-1,672	-2,214	-2,707	-3,150	-3,543	-3,400
67	Net Book Value		0	526	1,930	3,141	4,318	4,825	3,753	2,719	1,725	771	-142	-532
	Carrying Costs on Average NBV													
68	Return on Equity		0	10	45	93	137	168	158	119	82	46	12	-12
69	Interest Expense		0	10	48	99	145	178	167	126	87	49	12	-13
70	AFUDC		0	0	0	0	0	0	0	0	0	0	0	0
71	**Total Carrying Costs**		0	20	93	192	283	346	325	245	168	95	24	-26
	Income Tax Expense													
72	Combined Income Tax Rate		33.00%	32.50%	32.00%	31.00%	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	0	10	45	93	137	168	158	119	82	46	12	-12
74	Gross up for revenue (Return / (1- tax rate)		0	14	66	135	197	242	227	171	118	66	17	-18
75	Less: Income tax on Equity Return		0	5	21	42	60	74	69	52	36	20	5	-5
76	Net Income (equal return on equity)		0	10	45	93	137	168	158	119	82	46	12	-12
	Income Tax on Timing Differences													
77	Depreciation Expense		0	0	53	198	339	491	591	542	493	443	392	-142
78	Less: Capital Cost Allowance	Line 92	0	79	353	677	912	1,016	789	406	135	-57	-195	-294
79	Total Timing Differences		0	-79	-300	-478	-573	-525	-198	136	358	500	587	152
80	Income Tax on Timing Differences		0	-26	-96	-148	-175	-160	-60	42	109	153	179	46
81	Before Tax Revenue Requirement [=Line 52/(1-tax)]		0	-38	-141	-215	-252	-230	-87	60	157	220	258	67
85	**Total Income Tax**	Lines 75 + 81	0	-33	-120	-173	-191	-157	-18	112	193	240	263	61
	Capital Cost Allowance													
86	Opening Balance - UCC		0	0	447	1,551	2,284	2,887	2,869	1,599	702	66	-388	-715
87	Additions to Plant		0	526	1,456	1,409	1,516	998	-481	-491	-501	-511	-521	-532
88	Subtotal UCC		0	526	1,904	2,960	3,800	3,885	2,388	1,108	201	-445	-909	-1,246
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	861	480	211	20	-116	-214
91	CCA on Capital Expenditures (1/2 yr rule)		0	79	218	211	227	150	-72	-74	-75	-77	-78	-80
92	Total CCA		0	79	353	677	912	1,016	789	406	135	-57	-195	-294
93	Ending Balance UCC		0	447	1,551	2,284	2,887	2,869	1,599	702	66	-388	-715	-952

FortisBC Inc.
Capital Project Analysis
Distribution Substation Automation Program

Option:1

Line No.		Year: Reference	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	-62	-63	-64	-66	-67	-68	-70	-71
2	Depreciation Expense	Line 64	-532	-542	-553	-564	-575	-587	-599	-611
3	Carrying Costs	Line 71	-41	-41	-42	-43	-44	-45	-46	-47
4	Income Tax	Line 85	-81	-62	-49	-40	-33	-29	-26	-24
5	Total Revenue Requirement for Project		-715	-709	-708	-713	-720	-729	-740	-753
6	**Net Present Value of Revenue Requirement**	10.00%								
	Rate Impact									
7	**Forecast Revenue Requirements**		297,600	303,600	309,700	315,900	322,200	328,600	335,200	341,900
8	Rate Impact		-0.24%	-0.23%	-0.23%	-0.23%	-0.22%	-0.22%	-0.22%	-0.22%
	Annual Incremental Rate Impact over previous year		-0.18%	0.01%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
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%
11	Debt Component		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%
13	Debt Return		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
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									
43	Initial engineering, estimating, procurement									
44	Capital Cost Subtotal									
45	Contingency (10%)									
46	AFUDC									
47	Cumulative Project Cost Subtotal									
48	Estimated Annual Capital Savings		-553	-564	-575	-587	-599	-611	-623	-635
49	Total Cash Outlay in Year		**-553**	**-564**	**-575**	**-587**	**-599**	**-611**	**-623**	**-635**
50	Cumulative Cash Outlay		1,774	1,209	634	47	-551	-1,162	-1,785	-2,420
51			0	0	0	0	0	0	0	0
52	Cumulative Project Cost		1,774	1,209	634	47	-551	-1,162	-1,785	-2,420
53	Additions to Plant		-542	-553	-564	-575	-587	-599	-611	-623
54	Cumulative Additions to Plant		2,327	1,774	1,209	634	47	-551	-1,162	-1,785
55	CWIP		2,316	1,763	1,198	623	36	-563	-1,174	-1,797
	Annual Operating Costs / (Savings)									
56	Estimated Cost Savings		-138	-141	-144	-147	-150	-153	-156	-159
57	Communications - Leased Line Costs		70	72	73	75	76	78	79	81
58	Software Maintenance Costs		6	6	6	6	7	7	7	7
59	Total Incremental Operating Costs (Savings)		-62	-63	-64	-66	-67	-68	-70	-71
	(Forecast inflation rate 2%)									
	Depreciation Expense									
60	Opening Cash Outlay		2,869	2,327	1,774	1,209	634	47	-551	-1,162
61	Additions in Year	Line 53	-542	-553	-564	-575	-587	-599	-611	-623
62	Cumulative Total		2,327	1,774	1,209	634	47	-551	-1,162	-1,785
63	Depreciation Rate - composite average		10.00%	10.00%	10.00%	10.00%	10.00%	10.00%	10.00%	10.00%
64	Depreciation Expense		-532	-542	-553	-564	-575	-587	-599	-611
	Net Book Value									
65	Gross Property	Line 54	2,327	1,774	1,209	634	47	-551	-1,162	-1,785
66	Accumulated Depreciation		-2,869	-2,327	-1,774	-1,209	-634	-47	551	1,162
67	Net Book Value		-542	-553	-564	-575	-587	-599	-611	-623
	Carrying Costs on Average NBV									
68	Return on Equity		-20	-20	-21	-21	-21	-22	-22	-23
69	Interest Expense		-21	-21	-22	-22	-23	-23	-24	-24
70	AFUDC		0	0	0	0	0	0	0	0
71	**Total Carrying Costs**		-41	-41	-42	-43	-44	-45	-46	-47
	Income Tax Expense									
72	Combined Income Tax Rate		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	-20	-20	-21	-21	-21	-22	-22	-23
74	Gross up for revenue (Return / (1- tax rate)		-28	-29	-30	-30	-31	-31	-32	-33
75	Less: Income tax on Equity Return		-9	-9	-9	-9	-9	-10	-10	-10
76	Net Income (equal return on equity)		-20	-20	-21	-21	-21	-22	-22	-23
	Income Tax on Timing Differences									
77	Depreciation Expense		-532	-542	-553	-564	-575	-587	-599	-611
78	Less: Capital Cost Allowance	Line 92	-367	-421	-462	-495	-521	-542	-561	-578
79	Total Timing Differences		-165	-121	-91	-69	-55	-45	-38	-33
80	Income Tax on Timing Differences		-50	-37	-28	-21	-17	-14	-11	-10
81	Before Tax Revenue Requirement [=Line 52/(1-tax)]		-72	-53	-40	-30	-24	-20	-17	-14
85	**Total Income Tax**	Lines 75 + 81	-81	-62	-49	-40	-33	-29	-26	-24
	Capital Cost Allowance									
86	Opening Balance - UCC		-952	-1,127	-1,259	-1,361	-1,442	-1,508	-1,564	-1,614
87	Additions to Plant		-542	-553	-564	-575	-587	-599	-611	-623
88	Subtotal UCC		-1,494	-1,680	-1,823	-1,936	-2,029	-2,107	-2,175	-2,237
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		-286	-338	-378	-408	-433	-452	-469	-484
91	CCA on Capital Expenditures (1/2 yr rule)		-81	-83	-85	-86	-88	-90	-92	-93
92	Total CCA		-367	-421	-462	-495	-521	-542	-561	-578
93	Ending Balance UCC		-1,127	-1,259	-1,361	-1,442	-1,508	-1,564	-1,614	-1,659